Hydrogen Market and Price Formation Considerations: A European Perspective

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Preface

The European Union and the Dutch government have grand plans to create a clean (green and blue) hydrogen economy as quickly as possible as part of the energy transition. The formulated EU goals for 2030 can be called very ambitious. They involve an investment that could amount to around Euro 30 billion in the Netherlands alone over the next 6-7 years if current plans are realized. The latest reports from the market indicate that this is a conservative estimate. On October 16, the Minister of Economic Affairs and Climate wrote to the Parliament that the total costs (regarding the offshore part of the grid infrastructure) for the period 2032-2057 were estimated by Tennet last year at an average of Euro 2 billion per year and that these have now risen to Euro 3.6 billion, or 80% higher. From this it can be concluded that the aforementioned costs specifically for connecting offshore wind farms for the purpose of generating green hydrogen could be Euro 17 to 21 billion higher. Also, the Euro 30 billion is based on Euro 2 billion per 1 GW in cost reductions compared to Shell's hydrogen plant currently under construction in Rotterdam.

If all plans for 2030 are realized and further expanded in the coming decades, the future energy system of the Netherlands will consist of far-reaching electrification based on green and nuclear electricity, hydrogen produced from green electricity and renewable biomass/fuels, in addition to a smaller, but for the time being still a significant proportion of oil, natural gas (including CCS) and coal.

The European Commission has set a target of 10 million tonnes of green hydrogen (renewable fuels of non-biological origin (RFNBOs) produced from renewable energy) being produced within the EU by 2030 and 10 million tonnes of green hydrogen being imported from overseas friendly countries. The Dutch government aims to produce c. 0.5 million tons of green hydrogen in 2030, and to import just under 1 million tons of green hydrogen (source: HyXchange/TNO/Berenschot, April 25, 2023). This is far less than what would be expected on a pro rata basis given the significant refinery, petrochemical, fertilizer, and steel industries in the Netherlands. After all, 58% of current European (grey) hydrogen production and consumption occurs in NW Europe, with the Netherlands the 2nd largest user after Germany.

The question is not whether this is going to happen. That is already clear: no, and it will never succeed by that date. And there are good reasons not to want it that way either. Despite the much (preparatory) work in the Netherlands on realizing the green hydrogen chains and thinking through the conditions under which this could be achieved, the goals seem unachievable from the outset. There is too big a gap between the goals and what can reasonably be realized. This is not just a matter of what needs to be built. More importantly, there is a big gap in thinking about market formation and price discovery of both hydrogen and electricity, and how this will manifest itself in 2030 and beyond. The key question is how we will achieve the goals, when, and by whom? Because it is clear that the strategy now pursued by the government is not working and requires major adjustments:

- Currently, there is no hydrogen market, not locally, and not internationally. The gray hydrogen (made from natural gas or residual gases) that is produced is 'captive' - for its own use - or is arranged bilaterally through a long-term purchase contract, where the producer is just around the corner from the buyer.
- There is no idea yet what the market price will eventually be, how it will move, and according to what benchmark the price of green hydrogen will be determined. Some want to make the hydrogen price dependent on the electricity price in Euro/MWh, which is currently still determined by the natural gas price for most of the year. Others look at the ammonia price, which is a derivative of the gas price because ammonia is made from it and is priced in $/ton. Thus will the price of green hydrogen soon be determined by local electricity prices or by the global market for LNG and ammonia?
- Hydrogen is a gas, not an electron; this implies that the dynamics of the hydrogen market are closer to those of the gas market than to the electricity market. For example, you can transport hydrogen by sea and stored it. Neither is possible with electricity. Government strategies now show that Europe needs to import more hydrogen than it can generate itself in the coming years. HyXchange's reports confirm this.
- There are currently (virtually) no guaranteed buyers who want to enter into long-term contracts at fixed prices. Where such contracts exist, they are secret and between subsidiaries of the same group. In addition, there is the price of CO2 and levies,

taxes and subsidies, all of which have a major political country risk. So no developer of a green hydrogen plant in a free global market economy knows what its future revenues will be in the coming years. Both volume and price are unknown and difficult to predict for the coming decades.

- Investment costs are much higher than assumed until very recently, and cost inflation and possible cost reduction are highly uncertain. The same applies to the costs of green electricity, coming from wind farms yet to be built in the Dutch North Sea, which are needed as a feedstock to produce green hydrogen. The three largest European listed wind farm developers and wind turbine suppliers have seen their shares under heavy pressure for almost 3 years. The same is true for hydrogen suppliers.
- No one knows how many days per year the electricity price is so low that it is worth turning on the hydrogen plant, not just in year 1 but every subsequent year for the next 20 years. Annual electricity costs are the second largest cost item after the initial construction costs. To ensure that green hydrogen does not price itself out of the market, the electricity must actually be free, at least very low. To ensure this, hydrogen developers will want to enter into long-term optional supply contracts to buy as much electricity as possible at a maximum fixed price, but which does not have to be purchased if the price is too high. The alternative is not to use the purchased electricity but to sell it back to the market. Without a clear picture of expected sales revenues and operating margins acceptable to the owners and their bankers, no project is investable.
- The 2030 targets are guiding but not physically implementable in practice. There is a maximum of 5 years left for all offshore wind and green hydrogen projects to be approved and then built by 2031. The plans indicate the wrong order when projects must be ready. The completion of all offshore wind projects is heavily concentrated for the years 2029-2031. This self-imposed deadline creates a boom-bust cycle that is very cost-prohibitive. Everything must be ready at once - and certainly not in the wrong order: offshore wind farms, power cables and connections, hydrogen plants, converted gas pipelines to transport hydrogen, and installations and factories to use the hydrogen. For imports, there is also a need for green ammonia import terminals and re-cracking plants. This all must take place simultaneously in competition with all the other countries in the world that have similar plans, of which environmental

targets are strongly grouped around 2030 for policy purposes. The question is whether the Netherlands has enough money to hijack all the materials and equipment away from other projects around the world, let alone whether the country has the people for it to build it all in a very short period of time after having completed their time-consuming development and negotiation phases successfully before they can approve their projects to proceed with construction. The same applies to Environmental Assessment (MER-reporting) analyses, and permits and other government-related approval procedures.

- By the end of 2023, 4.5 GW of offshore wind operational. In that year there were 315 hours of negative electricity prices and 1705 hours unbalanced power. A record price of minus Euro -1449/MWh to Euro -1852/MWh was realized in the week of 27 October to 2 November last year because of large wind variation. The Dutch government has the ambition to have 21 GW of offshore wind operational by 2031. About 15.4 GW is targeted for completion between 2029-31. Such massive increase will definitely have its impact on the price of electricity and its price formation. How much, however, is unknown. In April 2024 the Dutch government will auction 2x2 GW of offshore wind. It will be highly interesting to see who will bid, who will purchase the power from these new offshore wind parks and against what price, and how much of the offshore wind parks will be dedicated to green hydrogen.
- Prospective bidders have to ask themselves what the annual average wholesale electricity price will be for at least until 2045, or have to find a willing buyer to underwrite a contract that guarantees a minimum price for those years. It also have to assess how much offshore wind will be successfully auctioned in successive tenders. It also have to assess how much will be allocated / dedicated to green hydrogen. For 4 GW of electrolyzers in the Netherlands in 2030 you need at least 5 GW of offshore wind. A part of the Dutch offshore wind is also for electrolyzers in Germany. Not or slower roll out of green hydrogen will automatically mean that more electricity has to be sold to clients that want to electrify their energy use. For them grid congestion is a big risk and the state monopoly Tennet and the regional municipality owned grid operators are far behind schedule to build new power networks.
- Given the risk and uncertainty profile, it will be nearly impossible to say something sensible about average annual power prices for the period post 2031 when the 21 GW must be operational (and with the ambition to growth it further to 70 GW). Hence

prospective bidders and green hydrogen developers better use option theory to formulate the value of these projects and to write off any bid amounts to be paid while postponing Final Investment Decisions as long as possible until more certainty is achieved. In the meantime the risk profile along the offshore wind to green hydrogen clients needs to be reduced and acceptable value needs to be seen before the start of building these value chains.

Investors

All these challenges apply just as much to the projects to be built in friendly overseas countries. However, hydrogen is very expensive and energy-inefficient to transport via ships. First, the green hydrogen – made with electricity from the sun and/or wind – must be converted into green ammonia, methanol or another liquid hydrogen derivative and then shipped and stored, after which a decision must be made in the Netherlands whether or not to sell it as a derivative such as green ammonia or crack it back into green hydrogen. The total energy losses to get from wind to hydrogen are substantial. Along the entire chain, independent parties, such as electricity producers, utilities, hydrogen producers, ammonia producers and back-crackers, port companies, shipping companies, logistics storage and transshipment companies will have to determine if, when, and how much they want to invest in these long, fragmented hydrogen chains and be willing to take credit risks on other parties active in the chain, and convince their banks to do so as well in order to get the financing. Parties will try to limit the number of parties through vertical integration or by organizing strong consortia of likeminded companies, as far as EU regulations allows. A high degree of trust between the parties is necessary that manifests itself in comprehensive legal agreements and contracts. Orchestrating the value chain should greatly reduce the risk profile and give a better view of where the profits will fall in the chain. Europe is skeptical about this because they fear the creation of an oligopoly. The NortH2 project was a good example of this.

In addition to the commercial companies in the value chain, there are also state-owned companies in the chain: In the Netherlands, the production of green electricity is commercial, the transport of the electricity is through state-owned company Tennet, the production of green hydrogen is again commercial, the transport of hydrogen is through state-owned company Gasunie, and the marketing and sales are commercial again. Future transport of green ammonia is still unknown. Abroad, this can be entirely in commercial hands (for example in the US and Australia) or entirely in the hands of the state (most African and Middle Eastern countries). The question is how risks are allocated among the various participants in these chains, and who receives what share of the profits? History in the oil and gas industry shows that this requires years of negotiations. To even start doing this, the 'prize' - the reward - must be attractive. And here too, legislation can hinder commercial parties from mitigating and absorbing risks. The hydrogen market cannot start where the LNG business is today; it will have to go back to the earlier LNG business models of the last century.

Improperly negotiated contracts between electricity buyers and developers in the US show well that the latter parties cannot automatically assume that they will be compensated for unexpected setbacks. Write-offs are now commonplace and show well where the risks fall and how important it is to conclude good contracts. But it gives no reason for governments to then just take over such risks and compensate companies for this. It does show that the wind industry is not yet mature, even though it has been around for 20 years.

The customers and users of green hydrogen, the refineries, petrochemical companies, fertilizer plants, steel mills, power plants, and other large energy-intensive industries, have no idea (at present) how much green hydrogen will be 'always' available for their continuously running industrial processes, and also have no idea yet how the prices of local hydrogen will compare to imported green hydrogen derivatives, how the 'price discovery' will take place, how expensive or cheap the electricity will be at that time, when it does make sense to run on green hydrogen, or not and switch back to gray hydrogen, natural gas or even slow down or switch off their factory, if that is possible. After all, if less electricity is produced from sun and wind than there is demand, and the difference is covered by natural gas-fired power stations, and as long as natural gas determines the price of all electricity generated, the electricity will soon be too expensive to turn on the hydrogen plant. This means that many more wind and solar parks will have to be built before natural gas is squeezed out of the electricity system (for large parts of the year). This could take many years, at least until sometime in the next decade. Before this is the case, you want to use electricity from sun and wind as efficiently as possible to reduce CO_2 emissions. It must be prevented that electricity from sun and wind for the production of green hydrogen results in the need to operate more or longer gas- or coal-fired power stations to meet the total Dutch demand and ultimately results in more emissions than less, even if one investor benefits but the other does not.

At the same time, through 'price discovery' in the market, a balance should be found between the production and price of electricity, natural gas (LNG), coal, hydrogen, hydrogen derivatives, and the price of CO_2. At the same time, developers of wind and solar parks need certainty about the selling prices of their electricity before they can decide to build new farms. Over time, they will have to reckon with lower revenues as more wind and solar farms come onstream, when there will be fewer days in the year where the electricity price (merit order) is determined by the gas price. But this will only occur at scale after 2030 when the next large wind farms are installed. Customers who are willing to accept high(er) electricity prices during part of the year are becoming increasingly important for them to recoup their investments. These customers must be prepared to 'forever' subsidize other customers, such as potential green hydrogen producers who can only afford to buy electricity at very low prices. There is a good chance that these customers are private individuals and companies with few alternative options for sustainability other than electrification and BEV car drivers, who are 'forced' into this by the government through financial repression. At the same time, wind developers must determine how many hydrogen projects will be built, which in turn will increase the demand for electricity as long as the price of the electricity supplied is very low. A true 'Catch-22'. However, there is also a possibility that a combination of relatively low natural gas and CO_2 prices and high total costs for the construction, operations, and maintenance of wind farms, the so-called LCOE (Levelized cost of electricity), will lead to a situation where natural gas is no longer always the dominant price determinant for electricity but electricity from offshore wind farms in the Dutch North Sea. This could happen, for example, after the next wave of new LNG projects come onstream starting in 2025/26 or some years later when the new wave of wind parks are commissioned in 2029-2031. At that point, it will be virtually impossible to produce green hydrogen on a commercial basis. In any case, it is very well possible that hydrogen will become an important, possibly a dominant, driver in the 'price discovery' of electricity prices. In such situation, power customers, wholesale and retail must then assess the impact of green hydrogen production on their electricity price. With so many risks and uncertainties, there is currently no robust economic calculation to be made that a developer can present to his board of directors asking them to commit billions of euros to the development and construction of large hydrogen plants (and offshore wind farms). Instead buying an option on a new offshore wind park license seems a reasonable route to get access to the plots.

The challenge

As mentioned above, the European Commission wants companies in Europe to produce 10 million tons of clean hydrogen themselves and companies to buy 10 million tons of clean hydrogen from other friendly countries 'all over the world', from Australia to Chile, and from Canada to the Middle East and African countries (source: COM(2023) 156, March 16, 2023). To produce 10 million tons of green hydrogen within the European Union, the European Commission has calculated that this would require the construction of c. 80 to 100 GW of hydrogen plants with a (green) electricity requirement of c. 500- 550 TWh. This can be supplied by wind, solar, hydropower and/or nuclear, with a focus on solar and wind. Based on their load factors, energy losses, and efficiency and conversion factors, the European Commission has estimated 150 GW to 210 GW of required renewable electricity generation capacity. If more electricity comes from offshore wind, you are at the lower end of the range. If more electricity comes from solar panels then more capacity is needed. In any case, the quantities involved are very large. To get a sense of this, at the beginning of 2023 the installed offshore wind capacity in Europe was 59.2 GW, 17.3 GW was under construction, and 9.9 GW had been approved for construction (source: TGS/4C, March 2023). The Netherlands is expected to have approximately 4.5 GW of offshore wind energy at the end of 2023 (source: RVO/Wind op Zee, April 2023). These offshore wind farms should then provide 15.8% of the current electricity supply for businesses and people at home. The latest published target for the Netherlands is 21 GW of offshore wind by 2031. Then 75% of our electricity needs must come from offshore wind turbines. Of the additional amount of new wind turbines, as much as 15.4 GW will only come online between 2029 and 2031, assuming that all projects are built and delivered on time. It is unclear who came up with the idea of building 15.4 GW all at once in such a concentrated period, and I am sure it has to do with the 2030 targets, but this requires a very large amount of manpower and equipment in a very concentrated period, which is very cost-prohibitive and thus price-increasing. In this regard, it is much better to stay away from government-driven boom-bust cycles and move towards a more even rollout. If indeed this large increase is realized in 3 years, it will certainly affect energy prices in the Netherlands. If it does indeed result in large amounts of electricity for which there is no demand during parts of the year, and results in low electricity prices on those days, then that could be purchased by hydrogen plants. So only after 2031 would it be useful to have those plants for this purpose, but not before. These plants then have a clear utility function, not necessarily for the production of green hydrogen for industrial processes.

The Dutch government's goal in the Climate Agreement is to have 4 GW of hydrogen factories by 2030; the target for 2032 is 8 GW. The European policy is that 42% of industrial hydrogen demand must be green by 2030. Of the total hydrogen demand in the EU, half would then be produced within the EU, and half would come from imports outside the EU in accordance with RepowerEU plans. Various estimates exist for hydrogen demand in the Netherlands: HyXchange/TNO/Berenschot calculates for their H2 market simulation a demand of 61 TWh of hydrogen in the Netherlands in 2030, which already assumes that a good part of the current gray hydrogen demand by industry will be replaced by direct green ammonia imports (source: HyXchange/TNO/Berenschot, April 25, 2023).

The 4 GW is equal to 20 hydrogen factories of the size of the Shell plant currently under construction in Rotterdam. Final investment decisions would therefore have to be made in the next 5 years for these to be built and to have them operational by 2030. Since electricity is the largest operational cost item, these clients must know where the green electricity comes from and at what price and other conditions for which they can buy it. By far the largest part, if not all, will be contracted directly or indirectly from offshore wind. To supply 4 GW of hydrogen plants with enough electricity, at least 5 GW of these yet to be built offshore wind farms must be built specifically for green hydrogen, assuming that they sell all their generated electricity to these plants and that these hydrogen plants are indeed going to be built. In this case, the plants run an average about 45% of the time per year, which is equal to the days when the wind blows on the North Sea (the load factor). At the other times, the hydrogen plants are off unless cheap electricity is offered from elsewhere.

Thus, based on this assumption, the hydrogen plant runs only when there is electricity from a contracted wind farm. However, during most of the time, electricity from the wind farms will be too expensive to make green hydrogen unless the price is set bilaterally and not linked to the market price. In practice, the hydrogen plants will then be idle for much longer than the 45% of the time per year. In addition, the hydrogen plant must compete with back-cracked green hydrogen, which is imported from the moment these types of value chains are established between producing countries and the Netherlands. Of course one must ask whether, and on what days, imported hydrogen is competitive. The market simulations carried out by HyXchange show that home-grown green hydrogen is not always available and can only supply part of the total target volume (42%). Given the target, these gaps must be filled during the year (with respect to volume and time of delivery) with a mix of imported ammonia (green and blue), which can then either be used directly or must be cracked back into hydrogen, and blue hydrogen (SMR + CCS). This mix depends on international commodity prices, specifically the price of natural gas (LNG), which determines the price of blue hydrogen, and the price of electricity as long as gas determines the merit order, and the price of imported green and blue ammonia, all taking the CO2 price into account too. Based on their assumptions, much more will be imported than produced in the Netherlands, assuming that we only have to pay the marginal cash costs of imported ammonia. This seems to me to be a wrong assumption because investors in our friendly countries will never invest in these types of export-oriented projects if they are not compensated for their capital investments. Would this be included, the import price would be much higher, which would greatly affect the mix.

Rather, it seems that the hydrogen derivative will be sold in the imported liquid form and will not be cracked back, but used as ammonia or methanol. In that case, both 'hydrogens' will go their own way and have their own 'price discovery'. When this will happen depends entirely on the price and the buyer(s) in the Netherlands who are willing to enter into long-term contracts with suppliers and developers 'abroad' and commit to the construction of their project. After all, without guaranteed offtake, these green hydrogen export projects will not be built.

In practice, I expect that the hydrogen plants in the Netherlands will be mostly off, and will become more effective only after a glut of offshore wind farms are built, which will then produce a lot of 'free' electricity for which there is no other demand. Only then does it seem that the hydrogen plant can provide hydrogen at an acceptable price. Another option is to agree on a completely different price regime, which must then be negotiated bilaterally by sponsors and the government and where European procurement legislation and anti-competition laws could be set aside, if necessary. After all, the current rules make it too complex and too risky to develop these kinds of long and fragmented value chains. Such a solution makes sense, for example for companies such as Shell, which thereby reduces its scope 1 and 2 CO_2 emissions (on time) and embeds the price of green hydrogen in the price of its oil products.

Sums and lessons

Contrary to what is commonly written and on which many proposals and plans are based, I expect that the cost of 1 GW of hydrogen plants will cost around $ 2.5 to 3 billion and not the $ 1 billion which is often mentioned and which is then supposed to drop quickly to under $ 500 million by the end of this decade. But an electrolyzer as such is not enough. For example, the cost of Shell's entire 200 MW hydrogen plant with all the associated infrastructure and buildings now costs more than $ 1 billion. This would mean that 1 GW of hydrogen plants would now cost $ 5 billion. To expect those to become many times cheaper to build within 5 years is an illusion. Cost inflation (for materials, equipment, and labor) will remain high for these types of projects if indeed they are all built simultaneously - 20 units or even more if chosen for smaller units. If only a few are built, there will of course be less scarcity and price pressure, but then the goals will never be achieved and the expected cost reductions as a result of learning curves and scale will not be achieved either.

At the same time, offshore wind farms must be built. Here too, all assumptions are outdated and no longer valid. Until very recently, the consensus was that the total costs for the construction, operations and maintenance of wind farms, the so-called LCOE (Levelized cost of electricity), would fall further from Euro 65/MWh towards Euro 47/MWh. However, they have now risen to Euro 97/MWh and rising. If you add the even higher network levies, the total cost for 2024 is calculated at Euro 132/MWh (source: Goldman Sachs, September 21, 2023). For the 15.4 GW of offshore wind farm projects to be built by the end of this decade, I believe an LCOE of at least Euro 175/MWh should be taken into account, if indeed all those grand European ambitions of installing three times as many wind farms per year will come true. After all, inflation will be very high if the 'whole world' starts building a lot at the same time. The oil and gas industry has seen this before, including during the investment phase from 2000 to 2008, when although inflation in the United States was 2.83% per year, the industry was confronted with double-digit annual cost inflation for several years, which caused total unit investment costs to go up from an indexed factor of 100 in 2000 to a peak index of 230 in the third quarter of 2008 (source: CERA, January 25, 2009). Similar unit cost increases were realized in the Australian LNG boom in the middle of the last decade. The oil and gas industry was able to cope with these devastating cost overruns because at the same time oil and gas prices rose rapidly and generated more revenues and profits. For example, Brent oil increased from $ 28.50 per barrel in 2000 to $ 97.26 per barrel in 2008. The question is whether this will also happen to electricity and hydrogen prices? In conclusion, this means that today 1 GW of offshore wind costs approximately Euro 3+ billion and could cost much more if we indeed scale up construction activities in the coming years to meet the 2030 targets (In the US this is estimated at c. $ 6.5 billion per 1 GW today, and in the UK c. GBP 3 billion per 1 GW (source Citi Bank, October 13, 2023); on October 17, Orsted announced to acquire 50% of the 253 MW Gode Wind 3 wind farm in Germany, which comes operational in 2024. Based on the sales price, the cost per 1 GW are Euro 3.7 billion).

So, the commercial part of the value chain consisting of 1 GW of offshore wind farms plus 1 GW of hydrogen plants now costs approximately Euro 5 to 6 billion, assuming that the next hydrogen plant will become much cheaper than Shell’s one. The planned 4 GW of green hydrogen production will then cost Euro 20 to 24 billion. On top of that will come the socialized construction costs of Tennet and Gasunie for transmission. Latest announced budget costs for the offshore part of Tennet’s infrastructure only for the period to 2031 is Euro 5.5 billion per 1 GW. Ballpark figure is thus about Euro 10 billion for a 1 GW offshore wind into green hydrogen value chain. The aforementioned Euro 30 billion thus seems to be a conservative figure. Hence, we are talking about very large sums, with great uncertainties and risks, and of which we already know that under the current price regime, hydrogen plants are largely at a standstill. From a commercial point of view, but also from an emissions point of view, it is not a good idea at all to build all those hydrogen plants that all turn on at the same time, but only for very short periods of time, namely when electricity prices are low, and otherwise stand still. Because why do we think it is a good idea to build many expensive projects that take up a lot of space, especially when transmission infrastructure is taken into account, and are seldomly used? And that it is then also intended that these plants should be subsidized with very large amounts of taxpayer money?

These large government-desired investments exist not only in the Netherlands, but throughout Europe, in the United States, and actually in the world. If it is up to the policymakers, we are going to build everything at the same time, as 3x as much per year as in recent years from the middle of this decade and then for many years to come. The IEA has calculated that 'the world' must go from $ 1.5 trillion in renewable energy investments per year to $ 4.5 trillion to meet the climate goals. Based on the abovementioned cost expectations, 10 million tons of hydrogen in Europe by 2030 will cost around $ 200 to 300 billion for hydrogen plants alone. Even if we assume that the 5 GW of new offshore wind farms per year in Europe in 2023 will grow to 17 GW of new offshore wind farms per year by 2029, resulting in 80 GW of new offshore wind farm capacity in place by the end of this decade (source: Goldman Sachs, January 2023), this is still not enough to meet the electricity needs of all the proposed hydrogen plants. At the same time, it is not the intention that all new parks will be specially built for the supply of green hydrogen plants alone because electrification of our society also needs to continue. But it will cost approximately Euro 240 billion to build 80 GW of offshore wind farms. So, to meet the European target, more than Euro 0.5 trillion will have to be invested in the next 6 years. In addition, a larger amount will be needed to get the green hydrogen imports done.

More about the objective to import vast amounts of green hydrogen from other countries. It would be unwise to think that hydrogen plants will be cheaper to build in countries that have no experience with this and have yet to build all the infrastructure. Many of these countries have no industrial base and are among the poorer countries with a weaker financial position. Country risks are often underestimated. Financing costs are significantly higher. Often they cannot even borrow such amounts. So, they are entirely dependent on Western companies that must find it attractive to want to develop, build, and operate these projects. European countries and multilateral financial organizations must finance and subsidize it cheaply so that the hydrogen can eventually compete with the hydrogen produced 'at home'. Assumptions for imported and recracked hydrogen prices based on marginal cash costs only need to be adjusted. The capital costs must also be included in the price formation. It is unrealistic to assume that countries will build these very capital-intensive projects without ever making a return on them, as is now suggested in the HyXchange reports.

Which solution? Which one would you rather not?

So there are still many questions to be answered to remove uncertainties and reduce risks, and to make the right decisions about how, where, how much, when, and by whom these complex green hydrogen chains can best be developed, built, and operated.

At one end of the spectrum, it may be decided to face reality and leave it to the market how to answer these questions. How the 'price discovery' of both electricity and green hydrogen will take place then plays a major role. This does not mean that there is no role for the government, but it should at most be facilitating, setting conditions and providing a framework, without the government taking over the role of the developer and taking over a large part of the risks without having the knowledge and skills in-house to assess and manage them. Possible limited subsidies may only exist to achieve a kick-start.

At the other end of the spectrum, a decision can be made to explore which commercial parts of the value chain to develop by the government through one or more of their energy state companies rather than handing out billions of euros in subsidies to commercial companies, while still taking over their risks knowing there is limited opportunity for them to assess and manage those risks. This side of the spectrum is quickly coming into view when the government realizes that the industry is not going to do things this way, something that has already been confirmed recently by Tata Steel, and can be distilled from the difficult conversations between the industry and the Ministry of Economic Affairs about the greening of their business processes. In such a system, 'price discovery' is determined by the rules of the game made by the government and no longer left entirely to the market. The government then regulates the price and its bandwidth within which transactions may take place . This means a far-reaching intervention in the functioning of markets, something that fits in with the current trend of thinking within the government.

In conclusion

In any case, it must be determined which of the industries, which from a political perspective should switch to green hydrogen, should be eligible for subsidies to keep them in the Netherlands. Many of these global companies came to the Netherlands in the last century because of cheap coal and later natural gas. The Netherlands had one of the largest gas fields in the world where gas could be produced at very low costs and was located almost directly 'under' the plants been built. And when gas became more expensive due to world prices, it could be subsidized in an orderly manner from the greatly increased state profits. However, those days are now over. These companies no longer have a reason to be in the Netherlands for cheap fuels and feedstocks, but possibly because of other location advantages. The question then is whether the Netherlands remains the right location for some, for example because most of their production is sold in Europe, or whether they expect renewable energy to become competitive in the foreseeable future and to be able to quickly comply with other environmental and climate-related legislation and targets.

If not, they will remain reluctant to invest in desirable solutions in the Netherlands (and Europe) and will choose, now or later, for another country where they expect the investments will ultimately deliver more shareholder value. Without the cheap Groningen natural gas and also having lost access to the relatively cheaper Russian natural gas, Europe including the Netherlands has now only the option to import expensive LNG. Natural gas in Europe now (autumn 2023) costs around $ 12/Mbtu, while in the United States it costs only $ 3.50/Mbtu. In oil equivalents at an oil price of $ 80/bbl, green hydrogen currently costs approximately $ 310/boe (source: Goldman Sachs, September 21, 2023). Hence, the Netherlands is no longer the natural location for some energy-intensive companies as it has always been. And it is not healthy for these companies to be on the government's drip for 'forever' to ensure their survival. For others, however, the Netherlands remains the right location, particularly because they can pass on the costs in their end products, which will only increase in price to a limited extent and will remain affordable, especially for European consumers. Internationally operating companies do not like to be on a drip 'forever' anyway. The political risks are far too great for that. In their view, governments may facilitate financially at the beginning of the project to get it off the ground, but they have a great resistance to being dependent on the government for years. Entering into 'contracts for difference' where the government takes over the upside and downside risks is therefore not the right solution, in my opinion. I am also concerned that these type of contracts will work out in a very unbalanced way without equal weight to the upside vs. the downside.

As mentioned earlier, it is not just about what needs to be physically constructed and built. More importantly, much more thought is needed in terms of market formation and 'price discovery' of both hydrogen and electricity and how this will manifest itself in 2030 and beyond. This work should then incorporate the remodeling of the internal electricity market, which the European Commission is working on. Without a good common understanding and proper visibility into this, it remains impossible to develop robust economic models and approve projects for implementation.

In any case, it seems to me that we should quickly say goodbye to the mandatory 2030 targets regarding green hydrogen. In the draft NPE, the development of green hydrogen is indeed more modest compared to previous targets and mentions a more substantial scale-up after that date. Also, an industry consultation round is taking place that may lead to new insights. The formal policy only leads to rapidly higher, inflation-driven costs, very large transfers of public money to companies - both for building infrastructure by Tennet and Gasunie in the Netherlands, and commercially in the form of subsidies and guarantees -, while those hydrogen plants will be hardly used as long as the electricity price is still too high for them, and do put a large demand on scarce land and resources. Socializing all these costs and risks by the government and passing the bill on to the taxpayer should be avoided. Risks should be placed with the party or parties that are best equipped to resolve them, and where this is not or only partially possible, with those entities who – as the natural owner of such risk -, can financially bear, assess, and manage these risks best. In my opinion, it is better to give them longer time to carry out their transition, for example until 2035, and let them decide for themselves how and when they want to build these hydrogen chains for their business operations (or come up with other solutions to achieve our goals). And thus, during that period, leave it as much as possible to the market as to how they want to solve this. During that time, the ETS price and the special Dutch CO2 tax in 2030 should provide sufficient incentive to make the new business case. But if they do not want to play, there will be no alternative for them than to lose their 'license to operate' at the end of the set period. This is bound to produce creative destruction. But this has always taken place in the Western capitalist world, so it is nothing new. On the whole, it has also brought us much further forward through research and innovation. In the meantime, the Netherlands will have to look for new, better and cleaner business models. Hopefully with the winners within the energy-intensive industry.

I. Executive Summary

i. Purpose of this report

This study is written from the perspective of private investors and market participants trying to figure out how the European ambitions for low carbon hydrogen and the EU-member state national ambitions can be translated in a business model to build these value chains with manageable risks for investors. To determine the value and risks around clean hydrogen and its value chains, a good understanding of the (future) price of hydrogen and its price discovery process is required. The key purpose of this study is to get a better understanding of the state of the industry and the likelihood that government ambitions will be fulfilled and targets for 2030 are reached. Of course, pricing of hydrogen is an integral part of this. Because hydrogen is a secondary energy source – like oil products out of a refinery -, also the primary energy source of green hydrogen is thoroughly analyzed. In Northwest Europe particularly offshore wind as the expected dominant supplier for hydrogen will be described in more detail. Also, for the power sector we investigate the price dynamics and the price discovery and price assessment that are poised to see major changes once RES power takes an increasingly bigger share in the total power production over the coming years. Most importantly, we are of the strong opinion that the consensus view about the evolving industry dynamics, both for green hydrogen and notably offshore wind, are increasingly outdated and need a realistic update. Particularly policy makers must accept reality that things are not moving as they like to see it. We hope that this report provides enough food for thought and help to build a new consensus that works.

ii. Key Findings and Recommendations

Low carbon or clean hydrogen is still in its infancy while EU-targets are very high compared with the current state of development. Many projects are in various stages of development but only a very few have been able to reach Final Investment Decision (FID) and move into the execution phase. During the time that the first projects are being prepared for FID and execution, the cost of capital and materials have changed substantially compared to the start of these projects. In offshore wind, projects have been confronted with, in some cases, a 30% to 40% surge in CAPEX and a doubling in funding costs in the last two years. Comparable cost increases are seen in the clean hydrogen space. Moreover, the EU and national governments keep adding more and more specific demands regarding production, storage, transportation, and types of demand that may be served, while making the legislative and financial prerequisites and policy programmes increasingly complex and unpredictable. Existing companies all look at how these clean hydrogen projects (and for that matter also offshore wind projects that will deliver the power supply) can fit into their asset portfolio and their customer base. The projects under development are struggling how to best mitigate the investment risks and to meet internal profitability criteria in this radically uncertain environment where price discovery is still non-existent. With mounting societal pressure to speed up the energy transition, governments that can afford it (or think they can) appear to increase their efforts to fill the gaps that private investors and financiers leave in their 2030 plans. Much then depends on the type and direction of government interventions to manage these infant industry investments risks and the ability to create a more predictable and investable investment environment and allow the market to create a proper price discovery process.

Today, there is no trading market for hydrogen and neither for clean hydrogen. The production of grey hydrogen today is relatively small and is predominantly produced for and used in captive markets, a business-to-business market. As a result, price discovery and price assessment for clean hydrogen doesn't exists. It is expected that the first clean hydrogen projects being built this decade will continue to be for captive use and will not help to overcome this price discovery constraint. It is still unclear when we can expect the first public trade of clean hydrogen and which market participants will actively participate in this new market. Instead, we expect that for the foreseeable future most clean hydrogen will find its way in end-products (primarily oil products including sustainable aircraft fuels, fertilizers, and chemicals) from which it is impossible to derive the cost or value of the clean hydrogen component used in the production of the end-product. Clean hydrogen transactions between parties will be on a bilateral basis and again there is no reason to expect that the terms of such trade will become public.

The price of clean hydrogen will be largely determined by CAPEX costs, the natural gas price for blue hydrogen and as a fuel to transport and inject the CO2 through CCS, and the power price for the massive demand of electricity in the production of green hydrogen through electrolyzers. There seems to be a broad consensus that CAPEX costs will come down very rapidly even faster than in the solar and wind power business in the last 5 to 10 years. We do not see this happening. To the contrary, CAPEX costs are only rising, not only for the first hydrogen projects but also for wind, and especially for offshore wind, the core supplier of power to produce green hydrogen in Northwest Europe. Levelized cost of energy (LCOE) for offshore wind, which had dropped by -65%, from c. Euro 200/MWh to a trough of c. Euro 65/MWh, have now increased to c. Euro 100/MWh (+50%) and are still rising. A mismatch between contracted revenues and input costs for legacy projects awarded before the 2021-2022 spike in equipment and funding costs will have its impact on profitability and the balance sheets of several developers. Developers are now being forced by capital markets to show more discipline and prudence and to change their mindset around capital allocation with a much stronger focus on value creation than top-line growth. We expect this will cause a slowdown in the development of projects and thus result in a much slower ramp up of hydrogen projects (and offshore wind parks) that will be sanctioned than the consensus view projected or what is needed to come anywhere close to the policy targets for 2030 set by governments. The expected learning curve from accelerated growth in new clean hydrogen projects will become a long time coming. In addition, unit CAPEX and OPEX cost inflation is high and poised to stay and could become an acute issue once accelerated growth will indeed start to kick off. Firsthand experience from the investment phase the oil and gas industry went through between 2000 and 2008/9 and after the Great Financial Crisis between 2010 and 2015 (notably in Australian LNG) can be explanatory for what could happen in the global RES and clean hydrogen market in the coming years if policy makers drive investments to triple in this space to achieve their ambitious climate change targets.

Natural gas prices will stay structurally higher in Europe because LNG is more expensive than Russian gas. Besides this one-time uplift, the future price will be set by well understood commodity market forces of (new) supply and demand and thus highly dependent on the short- and long-term demand for LNG in the various key markets around the globe. In turn, on the demand side this is set by annual GDP growth and government policies and their achievements regarding the energy mix and the faster or slower rise of RES and the rise or fall of coal as primary energy sources in their countries. On the supply side, this is dependent on the number of FIDs companies will take to build new upstream liquefaction infrastructure and develop new natural gas resources, and downstream LNG regas terminal and pipeline infrastructure to supply end-consumers. In that respect, a slower than wanted rollout of RES projects – i.e., less FIDs of wind, industrial solar, and green hydrogen, the more LNG is required to avoid demand destruction and (further) de-industrialization in Europe. Hence, the pace of RES and green hydrogen development will directly influence the total demand for American LNG. Both are communicating vessels and cannot be seen separately from another.

Natural gas prices still drive the merit order in the European power sector and thus sets the daily power price, even if its share in the production of electricity is small and decreasing. However, many legacy RES projects have power purchase contracts in place that have not been properly structured for the new realities of today. Due to much higher CAPEX and OPEX costs and much higher and unexpected repair costs, many companies will face losses and might have be forced to take impairments on their legacy projects (since the writing of this report, this actually happened on several projects). For their new projects, they will demand higher prices and will transfer risks to other parties along the value chain. If parties are not able to negotiate a new price and risk allocation equilibrium, new projects will not forthcoming. While agreement will be found on volumes, there will be much more uncertainty about the (future) price of electricity, their price markers, the price discovery process, and about price assessment. For the first years, natural gas is likely to continue to be the price marker. But there is much more uncertainty for that to continue in the longer term. This will be highly dependent on the pace of RES projects being sanctioned and built, as well as of the outcome of announced plans to fully revamp and re-regulate power markets in Europe. In Europe there is a strong political will to orchestrate energy markets to achieve low, stable, and predictable energy prices for consumers, especially for retail and SME consumers, and become independent of world markets with respect to supply (security) and price (affordability), but instead to build as much as possible at home and in large quantities (availability).

In case of blue hydrogen, the cost will continue be set by the cost of natural gas. In case of green hydrogen the overarching question is when natural gas will no longer determine the merit order and the price of power in Europe. And subsequently, how the specific characteristics of RES will influence price formation and fluctuations (an intermittent power source with high upfront CAPEX costs, but low / no fuel OPEX costs). Moreover, the much higher LCOE for offshore wind today implies higher power purchase costs for green hydrogen developers, risking the possibility that offshore wind will outprice itself and will no longer be competitive. However, there is not a good substitution with attractive LCOEs at scale to replace offshore wind.

While RES / offshore wind developers are willing to sell their power to green hydrogen developers, and actually might want and need to do so to manage risks – as they did to the single customer big data center companies in the last wave of offshore wind developments, these developers are not yet able to sell hydrogen to end-consumers, other than to sell it to their affiliates for captive use. Only the "must do" companies, those that must bring down scope 1 and 2 GHG emissions in order to comply with law, meet legal agreements with governments, and/or to protect their license to operate, shall sign long-term hydrogen supply contracts in an inflationary cost environment. Most of that will be internal contracts within their group of companies. Hence, how, and how fast, the market – i.e., volumes produced and traded – in practice will develop is highly uncertain. It is unlikely that green hydrogen producers will buy electricity from other suppliers than large scale (500MW – 1 GW+) offshore wind developers. Solar and onshore wind is too small and fragmented for this big hydrogen business, and buying all power demand spot is seen as too risky.

Consensus exists that domestic electrolyzers – onshore and offshore – will only be used at times of excess power production for which is not readily demand and prices are low (or negative). The electrolyzers thus will be built as system-serving electrolyzers, primary as variable and system-serving stabilizers of flexible loads. Load factors vary between 4,000 and 6,132 (of the 8,760 hours a year). However, it will take a long time before we have so many hours a year of oversupply that prices are low and competitive. In addition, energy-intensive industries, including incumbents now consuming grey hydrogen, run 24/7 and need clean hydrogen as a base load, not randomly, if and when available. Hence, in case of system-serving electrolyzers they always must have a reliable backup be it grey hydrogen, natural gas, through storage, or an imported clean hydrogen carrier. It is unclear how the first industry developers such as the refiners, chemicals and fertilizers will use their electrolyzers once built. But with more active government push, it is well possible that the clean hydrogen market will be divided not only between stationary and mobility markets, but also between base-load driven industry markets and flexible, on an if-and-when-available, power market. Governments might see more merit in influencing local utilities to aggressively build system-serving electrolyzers to capture excess power at very low prices when demand is lower than available RES production, while commercial companies might take a more conservative approach. Of course, this requires a massively oversized RES supply base designed for guaranteed supply from RES at days when there is less solar, wind and/or hydro available and backup capacity has be downsized to minimum acceptable levels.

In that respect, it will make a big difference whether the sponsors of the electrolyzer project requires (i) basic grid-tied, irrespective the source of the electricity, (ii) renewable hydrogen with grid-support, (iii) renewable only hydrogen, (iv) hydrogen utilizing excess renewable energy, or (v) renewable only hydrogen with 24/7 supply required.

So far, the implicit focus was on domestic production of power and clean hydrogen. However, to meet the policy targets, an equal amount of clean hydrogen needs to be imported by 2030. In some countries, such as Germany, perhaps even more than half. Preferably such supply will come from friendly countries that have good RES resources and where such export developments will not compete with domestic RES demand or compromise on ESG related aspects at the location where such export project is foreseen. What has been earlier said about CAPEX investments cost for the domestic market is probably even more applicable to these export-led projects. In most identified countries not only the wind and/or solar park and electrolyzer must be built, but also the hydrogen must be converted into a hydrogen derivative – green ammonia, methanol, Liquid Organic Hydrogen Carriers (LOHC) – for which a separate plant has to be built. In most cases these countries do not have an export port and logistics infrastructure readily available at the chosen location but these have to be built too. In addition, there is a lack of national champions and skilled labor to build these projects. Thus, as has been (and is) the case in the oil and gas industry, these large, complex and expensive projects need well-established project sponsors to build these projects under their leadership and provide the necessary equity funding and arrange the external debt financing. The idea that such projects will be developed spontaneous by the selected countries themselves and that these projects are only slightly more expensive (than in OECD countries) is flawed. Like in the oil and gas industry, overseas projects are far more complex and expensive to be built than for instance in Rotterdam or Galveston for that matter. Moreover, those international developers already have trouble to rank and screen their projects in North America, Europe, and other OECD countries, let alone that these remote projects will progress smoothly through the different phases of their global project development funnels. The risk-reward profile is just too uncertain and unfavorable and make it highly unlikely that any of these ambitious projects will progress towards FID in the coming five years to be operational by 2030. Only a very few countries, with a proven track-record in oil and gas, such as Oman and Saudi Arabia, can unlock the resources to make it happen. Also, countries such as Chile and Australia fall in this category. But in all other cases, it is foreseen that off-taking consumer countries must provide comprehensive programmes, including funding and financial guarantees, to persuade the global Integrated Clean Hydrogen Developers and Operators (IHCs) to become interested.

There is a consensus emerging that clean ammonia is the best option currently available for large scale hydrogen exports, while other derivatives will find their way in certain industry niches such as in shipping or specific energy intensive industries. As a result, many port authorities and the oil logistics and services companies active in those ports are considering building clean ammonia terminals to accommodate imports and to prepare for flourishing markets in hydrogen and hydrogen carriers in the near future. However, besides huge uncertainties around timing and the exact volumes that will be offered, a key question for them to be answered is the decision to keep the clean hydrogen as is, or to reconvert – crack it back into clean hydrogen. If it is kept intact, i.e., not be reconverted, the price of clean ammonia (or other clean hydrogen derivatives) will most likely be set by the price of 'normal' grey ammonia, which price is set by its feedstock, natural gas. In such a case, regional and now more global LNG prices will become the marker for clean ammonia. If both domestically produced clean hydrogen and imported clean hydrogen carriers have the same price marker, and CO2 price differentials are 'neutralized' by the Carbon Border Adjustment mechanism (CBAM) to avoid the risk of carbon leakage resulting from the EU Emissions Trading System, the price discovery process should work and will not favor one over the other. It will be then one clean hydrogen market, irrespective where the clean hydrogen has its origin in domestic markets or overseas.

However, if governments decide to regulate domestic markets (where hydrogen will be in a gaseous state) differently than imported clean hydrogen carriers (liquid state), and/or if LNG is no longer the price marker for domestic green hydrogen markets, price discovery and price assessment will be different for each sub-segment and will follow its own dynamic. In such a situation, market players who for instance own an electrolyzer but also have grey (and blue) hydrogen production facilities have to decide on a daily basis what to do: whether to purchase RES power for hydrogen production or not, and if mandatory under any long-term PPA, to use it or sell their contracted volumes in the market when power price differentials are attractive and thus to decide to produce grey, blue or green hydrogen, and/or to purchase imported a clean hydrogen carrier (and eventually convert it back into clean hydrogen). Some studies concluded that imported hydrogen will become the dominant driver in this arbitrage game, and thus will determine how many hours per day/year an electrolyzer will run (or stand idle to wait for favorable circumstances when the price of natural gas, electricity, imported clean hydrogen, own production and CO2 prices and other credits are right). We are not yet convinced that this conclusion is correct. It basically feels not good to build a billion-dollar value chain and then not to use it half the time but instead to purchase the clean hydrogen from an overseas producer (who will then strive to maximum utilization of its plant). Instead, we think it is more likely that the clean hydrogen carriers will not be converted back into clean hydrogen (other than for captive use) and thus that the trade in domestic clean hydrogen and overseas clean hydrogen will not merge into a single market, but will stay, as least for some time, two independent or remotely connected markets, each with its own price discovery process and price assessment. The size of each supply source and its availability will possibly also make a difference in how clean hydrogen markets will develop. Probably it is still impossible to predict how this all will eventually evolve when so much is in flux and how market participants will react and explore opportunities to maximize value from their decisions.

Export-led clean hydrogen projects must be big from the start to make an impact, to get the traction, and to drive down unit costs and to create a competitive position to win overseas markets. Hence, only a handful of global Integrated Clean Hydrogen Developers and Operators (IHCs) have the skills and resources to sponsor such big project developments. For many players the costs and risks involved are just too big. Companies that have the skills and financial means will, however, still demand negotiated transactions with selfselected like-minded partners to minimize fragmentation, credit risk and uncertainty along the value chain. Basically, they want to be allowed to set up classic LNG type of value chains for clean hydrogen, where the total value chain is orchestrated by a strong consortium of companies. Generally, this is not allowed under current anti-competition laws and supportive (draft) legislation, although the regulation on gas and power companies are stricter than for liquid companies. Governments are generally very suspicious about companies and their temptation to create monopolies/oligopolies and to maximize their rent through discriminatory avenues. However, we believe that hydrogen markets cannot and will not be developed on terms where global LNG markets are today, skipping many years of market development. Basically, hydrogen can't start where LNG ends. It took LNG markets 50 years to come there. Given the risk profiles and uncertainties involved, it is unrealistic to expect infant hydrogen markets could prosper and commercial companies will accept all risks (and risk categories) as they do now accept in hyper-competitive LNG markets.

European policy guidelines, as well as IRA guidelines, continue to be a source of uncertainty in many circles. While a lot of policy development and guidance has already come in and has given the RES and clean hydrogen sectors a positive direction with respect to the incentives, there is still scope for much more clarity to be obtained about the exact stipulations of the incentives, and equally for broader policies as well as the many individual programmes available, to streamline and simplify, to create consistency and alignment, and to make them fit-for-purpose and actionable. There are too many funding and support programmes at a regional, national and European level, each with specific targets and requirements. A whole new industry has emerged just to find out which programme is best suited for which specific hydrogen project in each individual member-state or country, and the time and effort needed to process applications and to receive approval are extensive and exhaustive. A sustainable market ramp up of clean hydrogen and the creation of a single market urgently requires uniform sustainability standards and certification systems for hydrogen and its derivatives, both for domestic production but primarily for imports. Upcoming elections in the coming year will create another level of policy uncertainty, which will cause further delays and postponements of decisions commercial companies might want to take.

The combination of all the above-mentioned challenges and constraints will cause project timelines more gradual to progress than expected and wished by policy makers in Europe and elsewhere. If investors cannot convince themselves that their economics are robust, the top-line revenues are predictable and have long-term visibility on operating margins, no board can take FID on a multi-billion project development. Moreover, this is not only the case for one individual project but for all required building blocks along the value chain. Companies will continue to assess their projects, but ultimate FID decisions will be postponed. This is exactly what we see now happening in Europe. A lot of motion but little progress.

Given the green hydrogen ambitions, such delays have potentially a big direct impact on the further development of new offshore wind parks, especially if LCOE stays at the Euro 100/MWh level or higher. If indeed the 2030 targets are met and all power will come from offshore wind, all new offshore wind additions this decade are needed to supply all electrolyzers. As a matter of fact, even if we triple the annual offshore wind additions in the coming years and keep that constant the following years, then still we need more power from other sources to supply enough electricity to all electrolyzers that are needed in 2030 to meet the targets. Hence, the green hydrogen market could (in such situation) become the overarching driver in setting the price of electricity in European power markets. However, if Europe fails in its hydrogen endeavors, it is ill-positioned to switch back to LNG. More likely, actions in this direction will only be taken when it is already too late, resulting in price spikes and supply uncertainty. Industries already realize this risk, even if the chances are small, and will price this risk in their strategic choices that they have to make. Moreover, if much less of the electricity production from offshore wind (in addition to solar and onshore wind) will ultimately not find its way into feeding electrolyzers to produce green hydrogen, alternative customers must be found, creating material downward price pressure making new renewable developments economically much more uncertain.

For governments the following options will come on the table: the first option they have is to accept reality and let it happen. In such situation, they will stick to their original schemes but accept industry will develop the projects on their terms and thus implicitly accept that their ambitions are overstretched. Commercial market forces will prevail. Basically, hydrogen will ultimately develop along the lines of global commodity markets. The second option is to actively intervene and to force to companies to build the project on time by accepting the risks these companies do not want to take and thus will be transferred to them, or even build the value chains themselves through state-owned entities. In this situation, risks and costs are socialized. Government and government-owned entities will take a bigger and much more ambitious role and responsibility in the development of the clean hydrogen value chains to keep the 2030 targets within reach. Commercial market forces will be bounded by strong government interventions and regulation. The market has less the characteristics of a global commodity market, where hydrogen act as a spot asset class in a similar way as any other commodity. Instead, it will become more a regulated (or hybrid) regional utility type of market, based on system-serving electrolyzers supplied by domestic RES resources. The third option is to change the mindset and to sit down with the handful of large CO2 emitters and global Integrated Clean Hydrogen Developers and Operators (IHCs)) to agree on more realistic, but still ambitious targets, perhaps even based on hard deadlines (when e.g. conversion of natural gas, LNG, coal or oil for RES and clean hydrogen must have been completed in order to maintain the license to operate), and then to find out and agree what is needed to keep the company in Europe or to let it go. This will not all be on a level-playing field, but tailor-made and negotiated per company and per project. Probably there are more options but stretching the targets further to even more ambitious levels is counter-productive and will not lead to any better or quicker decision to build the highly wanted value chains. Government should step back from a top-down approach and gain more sympathy and trust in the willingness of companies to change and to make the transition successful. In that respect, value chain orchestration in line with the historic large scale LNG value chains needs to be considered if needed. The alternative might be a fall back to option 2 if the overarching driver is to achieve the 2030 targets on time and national companies are available and able to deliver, or option 1 and to accept a gradual development of clean hydrogen markets and thus a slower decline of GHG emissions.

With respect to the cost involved, irrespective of the chosen route, the costs are likely much higher than currently anticipated and externally communicated. Hence, priorities should be set and avenues for cost reduction have to be explored. Not everything is possible.

More specific on price discovery and price assessment, the fragmentation of markets must be avoided. The rules of the game must be set for the total market, not only for a fraction of the market, either regional or defined by product specification. Defining the (size and boundaries of the) market is key. All existing commodity markets were developed by industry, not by governments. Exchanges were the platform to create efficient and liquid markets and to come to the best price given the prevailing market circumstances through a well-defined price discovery process and price assessment methodology. Rules were defined to overcome unwanted market speculation and market concentration. But above all, it has always been a liberal environment where business could prosper.

In 1999, ‘everybody’ was convinced oil prices would stay low forever, dubbed the 10 dollar oil world. However, when the Economist was quoting this on the believe of BP and Shell that prices would indeed stay low for the foreseeable future, it was exactly at the time that the then running exploitation phase was coming to an end. Shortly thereafter, oil prices started to rise, which ultimately led to a spike of $ 147/bbl in 2008. But it took the industry at least 4 years (to 2003) to accept this phenomenon and to understand the investment phase has started and a new super cycle was ongoing. Again, this is highly likely to happen again once U.S. shale can’t grow any longer which is expected to occur in the 2026 – 2028 time frame. By then we are not ready (yet) with our energy transition. On clean hydrogen, at best we are in the construction phased of many projects. On RES and more specifically on offshore wind, we must hope that indeed the industry has increased annual additions to levels described in this report. Because we are now in an exciting race between a new investment phase and a compelling substitution phase, and it is highly uncertain which one is going to win, there is a strong need to come to grips and accept more is needed to avoid a starved energy transition. At best, we buy time characterized by low but stable economic growth for the rest of the decade so that annual energy demand growth stays within the lower bounds of the forecasts made for the years ahead.

iii. Policy Report and Working Document

The Policy Report is supported by a Working Document. In this comprehensive document a fuller analysis is presented, which has led to the key findings presented hereabove. All key business aspects along the hydrogen value chain are described in detail. Some aspects are backward-looking and give oversight and insight how relevant sectors have developed over time. Others are more forward-looking and are absolutely open for debate and therefore more an intellectual exploration.

1. The first chapter (of the Working Document) describes the various value chains for hydrogen currently under development and in which sectors clean hydrogen will

make their inroads. This chapter sets the scene for further analysis in the following sections.

2. The second chapter presents the results of a two-year study on an advanced design of a 1 GW green hydrogen plant to be operational in 2030 including CAPEX cost estimates.

3. The third chapter describes at a high-over level the evolution of the RES market from 2000 onwards, and how this is likely to develop in the coming decade and how it will potentially enable the development of a hydrogen industry and markets.

4. In the fourth chapter several outlooks and scenarios for clean hydrogen are presented, as well as the latest targets for Europe.

5. In the fifth and final chapter we will make deep dive into price formation and price discovery and the establishment of a hydrogen exchange in the Netherlands, building on the successes of the Amsterdam Power Exchange (APX) established in 1999, and TTF, the Dutch gas trading platform, launched in 2003.

iv. Post-15 July 2023 events

Between the time of writing this report and the date of publishing, several company announcements have been made and events took place that confirm the worries presented in this document. As a result, capital markets have grown increasingly skeptical over the renewable industry's ability to create value from future investments. This has translated in a severe drop in share prices of many RES companies after already disappointing share performances in the preceding period. Most shares discount no (or negative) value form future growth. This was also seen in a failure in the UK where no new offshore windfarms were secured in the government's latest clean energy auction, despite the potential for 5 GW of projects. At the last moment, none of the offshore wind developers took part in the auction after having complained that the maximum price had been set too low for their projects to become profitable. This followed the U.S. where recently also 2 offshore wind parks were cancelled.

On July 26, 2023 Germany presented its 2nd National Hydrogen Strategy Update, the first National Hydrogen Strategy (NHS) had been presented in June 2020. This updated strategy announced that Phase 1, the start of the market ramp-up, which is described in the first strategy report, has now been successfully implemented based on the planned measures. In its status report (September 2021) and progress report (May 2022), the federal government described in detail what has been achieved to date. The biggest change versus the NHS of 2020, which in principle still applies, is the doubling of the national target for the expansion of electrolyzer capacity from 5 to at least 10 GW by 2030. In addition, the coalition agreement calls for infrastructure expansion to be created and for Germany to become the leading market for hydrogen technologies by 2030. Besides the doubling to 10 GW domestic electrolyzers capacity and the more than half of 95 to 130 TWh of forecasted hydrogen demand in 2030 (2.4 million tonnes – 3.3 million tonnes) must be imported, it is interesting that the German government requires that the majority of electrolyzers in place by 2030 must be located and operated based on a system-service approach. The document sees shipped clean ammonia as the main form of imports until 2030. Hence ammonia plays a very large role and, together with clean methanol and other possible clean hydrogen derivatives, will account for c. 45 to 90 Twh of imports (1.1 to 2.2 million tonnes). A large part will be allocated to dispatchable power generation. The report also spells out clearly that the government recognizes that large amounts of funding are needed to finance Germany's 2030 hydrogen import target. Such subsidies will come from Europe's IPCEI (important projects of common European interest), REDIII (Renewable Energy Directive), annual tenders for development of system-serving electrolysis, new funding guidelines for offshore electrolysis, and R&D programmes.

In the report reference is made to a pending clean hydrogen project by Tata Steel. In the meantime, the company has communicated that they have revised their corporate strategy, which will lead to the postponement of the development of green hydrogen, but to first built a grey hydrogen plant.

At the time of writing, the share price of Ørsted was Dkr 614.00 (July 6, 2023), a decline of c. 50% versus peak. It has then further collapsed to Dkr 377.90 a share, telling how investors currently view the offshore wind business.

At the beginning of the year, offshore wind LCOE price stood at Euro 80/MWh. The outlook was that it could further rise to Euro 90/MWh in 2024 and stay there for the foreseeable future. This is very different then expected in July 2019, when offshore wind LCOE in Europe were c. Euro 62/MWh and forecasted to further decrease to Euro 51/MWh today, 50/MWh by 2025 and Euro 47/MWh by 2030. However, cost inflation of raw materials, equipment, and labor, and rising interest costs and cost of capital has resulted in a rapid rise of LCOE, which is now standing at Euro 100/MWh or higher, with some projects seeing the LCOE rising to Euro 150/MWh.

On 12 September 2023, the EU Parliament voted to boost the deployment of renewable energy to 42.5% by 2030. Member states should strive to achieve 45%. The execution of the new targets is in line with the Green deal and RePowerEU plans. The legislation will also speed up procedures to grant permits for renewable energy power plants. In the transport sector, renewables deployment should lead to a 14.5% reduction by 2030 in GHG emissions, by using a greater share of advanced biofuels and more ambitious quota for renewable fuels of non-biological origin, such as hydrogen. The parliament is advocating that Europe now urgently need an EU electricity market design and an immediately shift to hydrogen for a greener transition.

During December 2023 and February 2024 meetings have taken place with many of the large energy-intense industrial companies, wind developers, utilities, commercial banks, the Dutch government, R&D advisory institutions and HyXchange, both on a one-o-one basis and through workshops. Without exception, the main findings of this report were underwritten. Discussions were more about the bandwidth of the conclusions than whether there was fundamental disagreement. There wasn’t.

Late February 2024 HyXchange delivred its final policy and technical reports. Also more international reports on green hydrogen exports / imports were published around that time. These reports haven’t been included in this study. However, in case of HyXchange, this study was made available to them before finalizing their final reports.

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II. Framing

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European Hydrogen – whatever color - today is not a commodity. The pricing of hydrogen is regional and subject to requirement and volume in the industrial application. Many sources, if not all, are captive. Much of the current production is co-located with demand. In the commodity sense, clean hydrogen is broadly uncompetitive. Therefore, adoption will be a function of the industries that have customers who are willing to pay for a renewable claim. Alternatively, there will be a structure of subsidies and taxes to ensure the adoption of hydrogen technologies. Expectations are that clean hydrogen will come down in price, and with reasonable learning rates this is probable. That said, one of the shortcomings of focusing on cost analysis is the volume and consistency argument, as well as the consequences of an evolving business environment, which includes more realism. The commodification of hydrogen still has to take off.

Clean hydrogen is Big Business. Only the largest companies can take these investments on their shoulders. The CAPEX cost are massive: We estimate that a 1-GigaWatt of offshore wind park to supply the renewable electricity costs c. $ 3+ billion. A 1-GigaWatt of electrolyzer currently costs c. $ 2-3 billion, or even more, based on the estimated cost of Shell's 200 MW electrolyzer project currently under construction, when all Outside Battery Limits (OSBL) costs are included. In the Netherlands – or for that matter Northwest Europe –, the commercial building blocks of a domestic hydrogen value chain will thus require c. $ 5-6 billion in CAPEX investment for a 1-Gigawatt system. We expect that this is still a conservative estimate. On top comes the offshore and onshore power cable and the conversion costs of natural gas pipelines into hydrogen pipelines to be executed by the state-owned energy companies. In aggregate, a 1 GW offshore wind into green hydrogen for sales to customers value chain is expected to cost $ 10 billion. Overall, there are increased technology and delivery risks. This creates uncertainty around the timing when these big companies will take Final Investment Decisions and thus on future production volumes and the performance of clean hydrogen and its derivatives.

Renewable hydrogen use is in its infancy. The ambitions in Europe are high, but many signals are flashing red. The industry is lukewarm to invest for many reasons. First many issues have to be tackled and feasibility and FEED studies first have to prove that positive Final Investment Decisions (FID) can be taken. Risks profiles versus expected returns for shareholders are still out of sync. Long-term visibility for shareholders is lacking. Costs and prices are moving in the wrong direction, contrary to most, if not all analyst reports and analysis, including those described in this report. Post-COVID, the business environment has changed materially and structurally. As a result the “EU will miss its ‘green’ hydrogen targets”, executives have said in the FT some time ago (Financial Times May 15, 2023). “There’s too much complexity and uncertainty. The Bloc is ‘very far off’ its goal to produce 10 million tonnes of carbon-free gas by 2030. Maybe half but not even.” Energy executives have said the EU’s targets for renewable hydrogen, a zero-carbon fuel deemed critical for heavy industries to emit fewer greenhouse gases, will not be achieved because of the bloc’s complex regulations. The bloc would need to significantly accelerate if there’s any chance of coming close to the EU’s target. “Companies can’t make final investment decisions because they don’t know what environment they’re working with.“

Moreover, governments want to start off from where the LNG business is today. However, that is very unrealistic and counterproductive. It took the LNG business more than 50 years and to go through the different stages of market development and competition before it became a truly global and liberalized market and before it completed the last mile to full price discovery on a global scale. Governments believe that hydrogen markets can just be built on top of more mature LNG markets, using the same policies, regulation as they do for natural gas. However, risks and uncertainties are far too big in this stage of development. First, nobody knows which volumes will be bought, besides the volumes they sell to themselves. There is no market volume and there is no offtake. Second, there is a lack of certainty on prices due to the great difficulty to define price in a fragmented market and in absence of historic references. With no proven price discovery process and nobody knowing how evolving electricity markets and power prices will impact the economics of hydrogen in say 5-10 years’ time, nor anybody fully understanding the dynamics of homegrown green hydrogen versus imported green hydrogen carriers, makes price forecasts any one’s guess. Without volume and price visibility, no one can determine its expected annual revenues in their economic valuation spreadsheets. Without a robust topline executives can believe in, business developers will never be able to convince their bosses to approve projects and to allow them to take FID on multi-billion dollar projects. External financing will never be made available. Third, greater technology and delivery risks reflected in construction delays and cost overruns, higher and unpredictable unit cost inflation in the years to come, and higher funding costs and equity risk premia resulting in rising pressure on IRRs, are creating uncertainty about the profitability of the projects under development but which are not yet sanctioned. Operations risk and unplanned maintenance and repair risks are underestimated and could be the next set back that will negatively impact expected returns, notably in offshore wind. In that respect, all past work has become flawed and invalid and must be put back on the drawing board to implement the latest knowledge and views on those input parameters for calculating the economics of each project. But before this, people must change their mindset first and acknowledge that we will not go back to pre-COVID times when money was cheap, inflation was low, risks were less well understood and too optimistically interpreted, and forecasts showed ever lower electricity prices, CAPEX costs and OPEX costs. Those who haven't adopted to the new realities yet, will very likely be confronted by nasty surprises, especially for the legacy projects currently under construction. In that respect, this capex intensive renewable industry will be confronted with the same realities the oil service and contracting world went through in the latest investment phase between 2000 and 2013: having to announce many set-backs on costs and delays on their legacy projects, start communicating earnings before unusual items (i.e. before unusual costs and impairments) rather than true profits, and trying to convince investors and stakeholders that the next cycle of awarded projects will be highly profitable. Fourth, there is still an absence of consensus on the definition of a green product with certification initiatives unevenly developed across sectors and national borders. Fifth, there are insufficient (perceived) incentives to 'buy green', despite growing pressure to decarbonize supply chains, and when these incentives are available, they are highly complex, fragmented, not fit for purpose, and not stable. Finally, the outlook for CO2 prices will be an important input parameter for assessing the project's economics and to compare them with the best alternative solution. Thus, without visibility on all these matters, companies will postpone decisions to actually build the projects, waiting for others to go first and to let them to learn the job. Moreover, companies must be allowed to develop the new green hydrogen value chains in a comparable way to those value chains that were organized in the 1990s and 2000s through negotiated deals with a few participants along the value chain to lower the credit risk and to better allocate profits along the value chain to allow building high trust regimes, given that they are locked-in for decades to come.

The question is now out whether Europe will prefer government intervention or leave it to the market to achieve its ambitions on time. Clearly the “Washington Consensus” - the term took on a life of its own, starting in the 1990s, when it became synonymous with privatization and easing of state control over national economies after the fall of communism - is making place for “New Public Management”. Although they talk about market, they implicitly mean (the implementation of new and far-reaching) government-controlled market mechanisms. In the Netherlands, the Dutch government impatiently concluded that the industry is not making enough progress with the energy transition and doesn’t expect that this will change for the better. For this reason it has published a draft report on ‘national plan energy system’ on July 3, 2023 in which it is proposed that the government will take the lead and will become far more pro-active in realizing the transition and to achieve the ambitions. The report promotes more government orchestration in all parts of the new energy value chains. Roles of national state-owned energy companies are likely to be expanded to parts currently left to the market. It recognizes this is a very different approach for a very open and market-driven economy, and perhaps this is the only way to achieve the Paris climate goals. How this dualism will pan out in the longer term remains to be seen. It is not that the industry doesn’t want (to make the transition happen), on the contrary, but with so much uncertainty, the global hydrogen race to 2030 is just too short, and the circumstances too different and risky to come up with a business model that may work.

The situation at the EU levels is also pointing into this intervention direction, which is breaking with the spirit of the Lisbon Treaty. Currently, around 160 MW electrolyzer output capacity is currently installed within the European Union (EU). Electricity-based hydrogen production is less than 0.3 million tonnes. The European Hydrogen Strategy from 2020 set out the objective to produce up to 10 million tonnes of renewable fuels of non-biological origin (RFNBOs), i.e., green hydrogen in the EU by 2030. The REPowerEU plan proposes to complement this goal by facilitating 10 million tonnes of renewable hydrogen imports by 2030. The European Commission proposed a full-fledged legislative framework for the production, consumption, infrastructure development and market rules for a future hydrogen market, as well as binding quotas for renewable hydrogen consumption in industry and transport. At an international level, the EU is now developing partnerships with third countries to create export opportunities to Europe. The EU is also establishing the European Hydrogen Bank. The objective is to close the investment gap and connect future supply of renewable hydrogen with its demand objective of 20 million tonnes of renewable hydrogen by 2030. The Bank will facilitate both renewable hydrogen production within the EU and imports. According to the European Commission, the Hydrogen Bank will provide more transparency on hydrogen demand, supply, flows and prices and will play a coordination role and facilitate blending with the existing financial instruments to support hydrogen projects. The amended Renewable Energy Directive (RED III) sets new targets for the minimum percentage of fuels that must be renewable fuels of non-biological origin (RFNBO). Delegated Acts will determine what can be counted as RFNBO. The European Commission also proposed reform of the European Union electricity market in March 2023. Through its inter-connectivity, this will also have far-reaching consequences on the development of the clean hydrogen market in Europe, both for domestically produced hydrogen and imported hydrogen (carriers). The proposal must delink electricity wholesale prices from natural gas prices to protect end consumers and industry for price spikes as witnessed in 2021-2022. The primary objective of the redesign of the internal power market is to stabilize prices. They believe that this is best achieved by enforcing utilities to enter into long-term power purchase agreements (PPAs) and by the implementation of so-called two-way contracts for differences (i.e. collars in financial terms). While the merit-order will remain, the market will be constrained by floors and caps on the price. Both are only applicable to RES power. Credit risk between parties entering into such agreements will be covered by member states so that power producers will receive secured revenues. In turn, this should enable financiers to increase their total-one-obligor ceilings on developers, who then should accelerate the investments in the energy transition. The mechanisms proposed will cause an (partly) expulsion of (commodity) markets as we know them today, or at least create a more governed-led hybrid market that is characterized by strong government-set market mechanisms in combination with the characteristics of global commodity markets. It might also lead to financial repression – measures by which governments channel funds from the private sector to themselves for an accelerated funding of the energy transition. Finally, the European Commission will implement a Carbon Border Adjustment mechanism (CBAM) to avoid the risk of carbon leakage resulting from the EU Emissions Trading System and address the risk of EU-based companies moving their carbon-intensive production abroad to take advantage of lower standards elsewhere, or that EU products are replaced by carbon-intensive imports.

Our reading is that the EU is eager to make the renewable hydrogen transition happen at whatever cost. The alternative of regressing to fossil fuels for its energy supply is not an option. Given the already tight fossil markets and the fact that 'the world' will see peak demand in oil, natural gas, coal and CO2 emissions soon, the outlook to become even more structurally dependent on less than friendly producer countries, and to be potentially confronted with serious security of supply and price affordability issues, while slipping on their climate change ambitions is non-negotiable. The optimistic presentation of 'no-brainer' clean hydrogen projects pits public opinion against investors that fail to replicate the calculations of government institutions. Furthermore, this optimism is a well-treaded path for large government-led public infrastructure projects – e.g. Eurotunnel and many large infrastructure projects in the Netherlands including railroads, airport expansions, tunnels, subways – where the CAPEX costs are optimistically presented to make the FID approval palatable, and then to present the inevitable higher bill as a consequence of cost overruns and delays at a later stage during the execution phase. In other words, it is highly likely that the costs of the renewable hydrogen roll-out will be much higher than now presented and destined to be socialized through taxes and charges. It remains to be seen how commercial investors will look at this scheme and how they will assess the political risks in relation to this new hybrid market model. For the time being, potential overseas developers tell us "show me the market; I don't see any buyer yet for clean hydrogen at a cost of 3x higher than LNG. Actually, I have no idea what the price of clean hydrogen will eventually be. I need visibility and signed long term sales purchase agreements to allow me to really develop my hydrogen project".

At the same time, there might not be a good alternative to just do what governments are now doing. Politically there is no way back (to structural fossil fuel import dependency and the accompanying risk of price volatility). Climate Change, affordability and security of supply may be just too important for government to not step up to the plate, whatever its costs, and whatever it takes. This said, with so many parliamentary and presidential elections forthcoming, it is uncertain how new governments will manage the price ticket of the energy transition and the impact they have on government budgets, tax levels and other social costs, and thus how they may balance their priorities.

i. Goals, targets, challenges, and realism

The European Commission estimated 500-550 TWh of renewable electricity as an input for up to 10 million tonnes of EU 'domestic' green hydrogen production. According to the EU, this would require between 65 and 80 GW of electrolyzers and recently upgraded to 80 GW and 100 GW. Based on communicated production levels of the Shell 200 MW plant, we estimate a demand for 93 GW of electrolyzers. A higher utilization rate from 57% to 70% could bring this down to c. 80 GW. This is based on a load factor of 70% (6132 hours p.a.) and an efficiency factor of 67%, and a conversion of 33 MWh/ton; 80 GW of electrolyzers produces then 10.8 million tonnes of green hydrogen. The original 65-80 GW already sounded very aggressive, in part because electrification of demand must also be implemented at the same time and results in caps for domestic hydrogen production for industry. A load factor of 70% too. Many see the electrolyzers running less hours during the year. And indeed, this is why the EU now quotes higher numbers.

If all electricity (to feed the electrolyzers) would be produced by offshore wind, according to our calculations, it would require an additional installed base of between 125 and 137.5 GW of offshore wind in the North Sea with an average 47% load factor (and more GW if blended RES). In COM (2023) 156 Final, dated March 16, 2023, the European Commission now estimates that the 80-100 GW of electrolyzers will require roughly 150-210 GW of additional renewable capacity. This is based on a blended RES production base and therefore higher than the aforementioned 125 and 137.5 GW of offshore wind.

Originally, the EU Hydrogen Strategy targeted a total investments of up to c. Euro 400 bn ($ 440 billion) to 2030. They now quote that: 'the total investment needs to produce, transport and consume 10 million tonnes of renewable hydrogen are expected to be in the range of Euro 335-471 billion ($ 368.5-518 billion), with Euro 200-300 billion ($ 220-330 billion) needed for additional renewable electricity production.' This update comes closer to our own calculations but this is still seen as a lower bound number. *NOTE: the EU text is fuzzy and political, in a sense that you could also read that the Euro 200-300 billion is included in Euro 335-471 bn. In that case the electrolyzer + all directly related costs are much lower than I believe it will be).* Based on consensus CAPEX cost of about $ 900 million per 1 GW, the 93 GW of electrolyzers would result in $ 84 billion. There are views that cost improvements in the coming years will reduce this CAPEX investment by half. The European Commission quote a CAPEX investment in electrolyzers of $ 55-82.5 billion. However, based on the CAPEX budget for the first 200 MW plant currently under construction (4-5 times more expensive), we estimate CAPEX costs three times higher at c. $ 200 to $ 250 billion for the electrolyzer and all related Outside Battery Limits (OSBL) costs, but excluding public power cables, pipelines, storage facilities and manufacturing capabilities. Tremendous cost improvements and extreme cost deflation are required to bring these amounts back into the direction of the original target, let alone to the consensus cost expectations for the end of this decade. In line with the 2030 targets, this must happen in the coming 5 years. If all electricity would come from North Sea offshore wind, this would require an additional CAPEX investment of $ 350-400 billion for offshore wind according to our calculations. Together with the $ 200-250 billion for the first generation of large electrolyzers, we estimate the aggregate CAPEX cost more in the order of $ 550+ billion. On top will then come all public power cable, hydrogen pipeline and storage costs. According to the European Commission, an additional $ 500+ billion will be needed in international value chains to enable the import of 10 million tonnes of renewable hydrogen derivatives. However, this might be much higher as the construction of such projects by western companies in emerging markets is generally more expensive than for instance at the U.S. Gulf Coast or in Rotterdam, while infrastructure and ports require massive expansions to facilitate the export. To trigger those projects and to pull the clean hydrogen towards Europe, the EU and its member states have to facilitate this development by providing financial support and long-term offtake contracts.

We are at the very first stages of New Business Development (NBD) in clean hydrogen. Most electrolyzer' projects have just entered the NBD funnel and are in the so-called 'Identify and Assess' phase, in which options are assessed, feasibility studies conducted, and concepts developed. Some projects are in the next "Select' phase. Those projects are described in this report for the Netherlands, a front-runner in clean hydrogen. In this phase, concepts are further worked out and selected, and pre-FEED and FEED (Front End Engineering and Design) studies executed. Several of these projects have or are at the point to enter the next 'Define' phase, where the sponsors are completing all the permitting and basic design work to enable them to take Final Investment Decision (FID) in the not-so-far future. Only once FID has passed, the next (4th) 'Execute' phase can start. For most projects – assuming they have gone successfully through all pre-FID phases – this will predominantly take place in the second half of this decade for those now been announced.

Most projects are still pre-FID, and thus ‘on the drawing board’. Only when more projects are successfully sanctioned, the real investment phase will start, where billions of dollars must be committed to this new clean hydrogen industry. Indeed, if the ambitions become reality, the lift-off will trigger RES 2.0 where electrons are going to meet molecules. Grey meets Blue and both meet Green; a premium will be paid comparable to renewable diesel vs. regular diesel, at least that is the idea. Solar will be further industrialized and directly coupled with wind to run 24/7. Many RES projects will become dedicated to a single hydrogen project. The number of customers per project will be small. As a result, in NW Europe, the economics of offshore wind will be determined by, or at least should consider, the price of clean hydrogen. Clean hydrogen requires very low electricity prices to become economic, or, more likely, consumers just end up paying far more for all types of clean energy – directly or indirectly through dedicated taxes and charges to close the competitive gap. Investment phases do not come cheap. Like in oil and gas in the 2000s when oil prices went through the roof, the likelihood that this will be replicated in the 2025-2035 period to build the foundations of a completely new energy system is high. At the same timer, overseas producers must determine in what carrier / derivative to convert the hydrogen, how to price it, and to which market to export. Parties involved have to agree on the overall risk profile and the prize. Both must be allocated to those involved along the value chain. To make it a commodity, it must have a price risk. Question is who is going to take this. Is there a profit zone along the value chain, and if so, where is it?

We believe that clean hydrogen begins with the de-carbonization of existing hydrogen end markets to reduce scope 1 and 2 GHG emissions. Therefore, we see the starting point of the clean hydrogen economy as the decarbonization of the c. 8 million tonnes of current dedicated fossil fuel-based (natural gas and waste gases) hydrogen production in Europe, and c. 70 million tonnes of pure hydrogen preliminary used in oil refining and ammonia globally. Additional end markets will be found in the steel industry and the production of renewable diesel and kerosine (Sustainable Aviation Fuels – SAF produced by HVO plants).

The U.S. IRA act is seen as a real game changer, also for Europe. European corporates love it. The U.S. has high-quality energy resources for clean hydrogen. With these resources, the U.S. could be a major region for clean hydrogen production, with sizeable domestic demand, competitive costs and prices, and the potential to export large volumes to Europe and other regions. The IRA has several dimensions. In random order we mention four: 1) It helps to battle climate change. Without the U.S. taking far reaching measures, the Paris goals are not achievable. 2) U.S. shale oil and gas is maturing and will soon plateau followed by a gentle, or perhaps steeper decline depending on capital allocation. To avoid returning to increasing import dependency as was the case in the 2000s, it has to make a start with the energy transition. 3) it creates jobs and stimulate innovation and is thus good for the economy and its competitive position globally. 4) The U.S. (and Canada) can free up more oil and gas for exports and together with larger renewable energy production help the rest of the world in meeting their energy needs.

While the U.S. has a bit more time to make the transition, it probably will do it faster for social-economic reasons. However, Europe has no time to lose. As the war in Ukraine grinds on, there is no appetite for Russian oil and natural gas to return. The Netherlands, long the largest European natural gas producer, has decided to permanently close its Groningen gas field this year. Europe is now heavily dependent on Norwegian gas, pipeline gas from Azerbaijan and some North African states, and most importantly, LNG imports, which it had to buy mostly in secondary markets, even the origin was the USA. More important, Europe doesn't want to simply replace Russian gas imports with gas imports from friendly countries. Instead, it wants to accelerate the energy transition to battle climate change and to foster more strategic autonomy in energy. RES and clean hydrogen are the chosen prime resources of the future. RES is on the right track but must accelerate materially, as further discussed below. Clean hydrogen is, as said earlier, is in its infancy. This report explores the current state, Europe's ambitions and what it will take to realize the plans.

ii. Natural Gas and RES In Europe

European policy makers never ever want to be confronted by a similar situation as in 2022 with unexpected high, volatile and uncertain energy prices again. Therefore, the overarching ambition is to build a clean energy system that results in relatively low, predictable, and stable energy prices for citizens and industries based as much as possible on domestic production. At some point, they believed that self-sufficiency was within reach, but that position has been abandoned because of the projected energy demand of industry.

Natural gas prices and wholesale power prices are much higher in Europe than in the U.S. Natural gas prices are now set by global and regional LNG prices and price dynamics. Global supply and demand and their growth outlook determine LNG prices and its price outlook. Economic growth (+/-), the level and outlook of (economic) development and industrialization, geopolitics, weather and climate related events, government policies and regulation, and alternative sources of primary and secondary energy in the energy mix will determine affordability, security, visibility, and reliability. Depending on which scenario you believe in natural gas supply and demand will structurally grow for the foreseeable future or will start to plateau later this decade before entering a period of structural decline. For each region this will be different, irrespective of their inter-connectiveness.

High, volatile, and uncertain energy prices could result in a material de-industrialization in Europe, especially for energy-intensive industries that are export driven and compete globally. In the Netherlands, many politicians support this shrinking concept for industries that can't – or don't want to – make the transition (fast). In Germany de-industrialization has unsettled politics, while also the EU Commission has recently voiced its concern about alleged dumping practices of Chinese companies. In how far Europe want to subsidize energy-intensive (and quite often polluting) industries in their journey remains to be seen, especially if those subsidies ultimately flow as profit to overseas headquarters of companies and governments. For instance, the government of the Netherlands wants to bring back GHG emissions from 157 million tonnes in 2022 to 102 million tonnes in 2030. A large part of this reduction must come from the largest industries in the Netherlands. The top-20 biggest GHG emitters are responsible for 1/3rd of total annual GHG emissions in the Netherlands. Eleven of those 20 companies are coal- and gas-fired power plants, four refineries, petro-chemical and fertilizer companies, and one large steelworks. All but one of these 20 companies are owned by foreign companies with their headquarters overseas. Some are based in Germany or Paris, but the others are British, American, Saudi Arabian or Indian companies. It is unclear today how the necessary investments to reduce emissions rank in their global project funnels and whether they will give priority to their Dutch subsidiaries over other opportunities elsewhere.

At a European level, natural gas is no longer seen as a transition fuel. To the contrary, the quicker a reduction in natural gas demand can be achieved (together with coal and oil), the better it is, even if this requires active demand destruction. Policy makers therefore will discourage the signing of long-term offtake contracts for LNG. (Security of) supply risks are perceived to be manageable. At times of tightness it is believed that the market will sort it out through spot markets transactions and market dynamics.

Natural gas demand in Europe was 496 bcm in 2019. Warmer weather, higher prices, increased focus on efficiency improvements, and a combination of industrial fuel switching and idling of production capacity, all helped to lower natural gas demand to fall to c. 421 bcm in 2023. A long-term outlook shows a gentle decline in demand to c. 400 bcm in 2030. Of course, the success in accelerating the roll-out of RES in Europe will make a big difference in the demand of natural gas. Equally, a good start of building green hydrogen will further help to bring gas demand down. But if both RES and green hydrogen will not grow as fast as the European Commission hopes, the likely consequence will be further de-industrialization. As a result, we would not be surprised if gas demand in 2030 would have fallen to 350 bcm by 2030, with a plus/minus 50 bcm variation level to compensate for days with lots or little renewable electricity and good or bad hydro-power seasons.

Europe has the ambition to grow renewables fast so that c. 75% of electricity (>1,200 GW) could be produced by RES (wind, solar, hydro and nuclear) across Europe by 2030 compared to less than 50% today. This requires a tripling of annual wind and solar additions to a peak of c. 120 GW per year in the second half of this decade, compared to c. 40 GW additions in 2022 and 29 GW per year between 2019 and 2021. Between 2023 and 2030, 762 GW will then be added (comparable to the U.S. RES additions in this time frame).

The pace has to go up materially. For instance, in offshore wind - a major building block for green hydrogen plans in Europe - currently 59.2 GW is fully commissioned globally, 17.3 GW is under construction and 9.9 GW has taken FID. The industry must build c. 183 GW globally by end-2030, of which c. 83 GW in Europe to achieve 126 GW of offshore wind been installed in European waters by 2030. This compares with the UK and Germany, the biggest offshore wind markets, having currently together 5.5 GW of projects that have passed FID but are pre-construction. The top-10 offshore wind developers, of which the top-3 are Ørsted, RWE and Iberdrola, currently have 5.6 GW under construction and 4.9 GW of new projects on which FID has been taken. Pre-FID these 10 companies have 81.6 GW in the different phases of development. By far, most of their portfolio is in Europe, followed by North America. However, progress is generally slow and many projects are facing cost overruns and delays. Impairments can't be excluded, which will result in companies taking a more conservative approach than an aggressive one. Permitting has also been slow but may improve. Overall, investments continue to remain very challenging and far below the rate required to even approach the stated 2030 goals. Projects remain at risk of not proceeding unless a financial resolution can be found to mitigate cost escalation, experienced since the offtake was secured. Industry inflation levels are well in excess of indexation rates in legacy contracts. Issuing of offtake contracts remains healthy but are still below the required level. "Expect more price risk sharing in future." are warnings recently communicated.

The apparent consensus is that both costs and prices in the wind sector will find its way to lower levels, while returns and risk profiles will improve. Also, it is assumed that the wind industry is big enough to take up the forecasted growth in additions. The current situation shows a different story. Developers are confronted with legacy projects that are not any longer profitable. Since 2019, the costs of raw materials have been increasing, resulting in cost inflation rates approaching 30%. The same applies to turbine prices. CAPEX per GW is up by at least 15-20% and are still rising. Funding costs have increased materially. WACC is up by 125bp. Pressure on IRRs is rising. Developers are faced with construction delays and cost overruns and more maintenance and repair issues. While cost are now falling from peak levels, an era of rapid investment acceleration will create tightness which generally result in upward price pressures (like in the oil and gas industry during the 2000-2008 high industry inflation investment phase). LCOEs have increased and are expected to stay higher than some years ago. Power costs are volatile and turn more often negative with more capacity installed. With the arrival of more RES in the equation, the merit order where natural gas generally sets the price will change, but nobody knows when or how. Moreover, the EU is attempting to restructure the internal power market to divorce the power price from natural gas in the merit order. Developers have become more selective, favoring value over volume. Some must preserve their balance sheet and are not able to take more projects on their plate. Several large players will ultimately hit their total-one-obligor ceiling, i.e. how much a bank is willing to underwrite their borrowing needs. It generally takes years to manage the legacy projects, absorbing enormous part of the time and effort of the management of the companies. In the worst-case investors start questioning the viability of the entire offshore business model and its ability to create any value from future growth. European oil and gas majors are already shrinking their RES businesses, moving away from utility-style returns in renewable electrons. RES contractors face similar issues. Smaller developers are leaving the market. All these constraining elements must be taken away to make the acceleration possible. More, not less developers are needed.

iii. Clean hydrogen ambitions in Europe

Besides RES, Europe is betting on clean hydrogen for those harder-to-abate sectors that cannot easily electrify and to store energy at times of plentiful solar and wind. This requires massive expansion of the electricity production and transportation system on top of the large amounts of renewable electricity that will be needed to electrify end-uses that are currently served by other energy carriers.

On July 8, 2020, the European Commission published its 2030 Hydrogen Strategy. This was the first concrete document in which they detail the central role that hydrogen is supposed to play in the European economy. The EU Hydrogen Strategy underpinned the birth of an entirely new hydrogen industry largely based on green hydrogen: against the electrolyzer installed base of 0.1 GW in 2020, the EU targeted 5.6 GW by 2024 (to produce up to 1 million tonnes p.a. of renewable hydrogen) and 40 GW of electrolyzers capacity within the EU by 2030 (producing about 5 million tonnes p.a. of renewable hydrogen) based upon an estimated demand of up to 10 Million tonnes per year of renewable hydrogen in the EU by 2030, and with a working assumption of 500 GW by 2050.

With the publication of the REPowerEU plan in May 2022, the European Commission complemented the implementation of the EU hydrogen strategy to further increase the European ambitions for renewable hydrogen as an important energy carrier to move away from Russia's fossil fuel imports. In the Staff Working Document (SWD(2022)230), which accompanies the plan, the Commission outlined a ‘hydrogen accelerator’ concept to scale up the deployment of renewable hydrogen, which will contribute to accelerate the energy transition and decarbonizing the EU’s energy system. The ambition now is to produce 10 million tonnes p.a. domestically and import another 10 million tonnes p.a. of renewable hydrogen in the EU by 2030. As part of the plan, stakeholders have accelerated plans to develop hydrogen pipeline transmissions, as laid out in the European Hydrogen Backbone initiative, which now targets 28,000 km in 2030.

Within the hydrogen accelerator measures, the Commission has also proposed to establish a global European hydrogen facility to create investment security and business opportunities for European and global renewable hydrogen production (COM(2023)156, published March 16, 2023). The European Hydrogen Bank is a financing instrument run internally by Commissioner services. It is not designed to be a physical institution. The main objective of the facility is to unlock private investments in hydrogen value chains, both domestically and in third countries, by connecting renewable energy supply to EU demand and addressing the initial investment challenges. It must foster the establishment of an initial market for renewable hydrogen. In autumn 2023, a pilot auction (competitive bidding) will be launched under the Innovation Fund, supporting the production of renewable hydrogen for European consumers. Furthermore, green hydrogen partnerships between friendly countries and EU member states must facilitate the promotion of the import of renewable hydrogen from those countries and contribute to incentivizing decarbonization. Together, the European Hydrogen Bank and the green hydrogen partnerships aim at delivering a framework to ensure that partnerships established by the EU countries and the industry provide a level-playing field between EU production and third-country imports.

The clean hydrogen ambitions are massive. 10 million tonnes p.a. of hydrogen domestically produced requires more RES power production. If all is to be produced green (and nothing blue) and all will be delivered on a stand-alone power-to-hydrogen basis, 500-550 TWh of electricity would require 125 GW to 137.5 GW of offshore wind (@ 47% load factor that is currently achieved at the North Sea). Portfolio optimization, a larger offshore wind share in RES and integrated with grid power production can further improve the needed capacity. But as described earlier, the EU now estimates roughly 150-210 GW of additional renewable capacity generating electricity, apparently based on a blended RES (solar, onshore and offshore wind) portfolio and at a lower average load factor. As a rule of thumb, one could assume that 1 GW offshore wind (on the North Sea) yields to 0.1 million tonnes p.a. of hydrogen. In any case, the required capacity is materially higher than the ambitious 80 GW of new offshore wind additions targeted for the remaining years of this decade.

Financially, the EU has multiple funding programs in place to support the investment needs identified by the REPowerEU plan. Reference is made to the European Commission's web page "EU funding Programmes and Funds 2021-2027".

iv. Clean hydrogen supply, demand and costs in Europe

In 2022, hydrogen accounted for less than 2% of Europe's energy consumption and was primarily used to produce refined oil and chemical products and fertilizers. 96% of this hydrogen was produced with natural gas, resulting in significant CO2 emissions.

Today, there are around 160 MW of electrolyzers in place and most of these are demonstration plants. The largest plant currently under construction in Europe is 200 MW, with a target completion date in 2025. The EU hydrogen strategy targets 6 GW of electrolyzers powered by renewable electricity by the end of 2025. The 40 GW target by 2030 will produce c. 5 million tonnes p.a. of clean hydrogen, now upgraded by the European Commission to 5.6 million tonnes. To achieve the 10 million tonnes p.a. of domestic production target, the European Commission now estimates 80 to 100 GW of electrolyzers must be built by 2030, a 24% increase to earlier quoted estimates. This equals to 400-500 plants of 200 MW each, like the one Shell is now building in the port of Rotterdam in the Netherlands. Moreover, in order to achieve this by 2030, all those 400+ plants needs to take Final Investment Date (FID) in the next 5 years in order be ready on time.

Achieving these ambitious targets has major implications for the power demand needed to run the electrolyzers – on renewables capacity and on gas and future hydrogen infrastructure. The Commission estimates that around 500-550 TWh of renewable electricity is needed to meet the 2030 ambition in REPowerEU of producing 10 million tonnes p.a. of renewable hydrogen (so-called RFNBOs). The 10 million tonnes ambition in 2030 corresponds to c. 14% of total EU electricity consumption. Based on the European Commission's working assumption of 500 GW electrolyzers by 2050, green hydrogen could thus become the largest electricity customer. Power demand for electrolysis alone could double European electricity consumption. It was estimated that c. 1,100 – 1.300 GW of dedicated RES capacity would be needed to meet the power demand required for the EU's 500 GW electrolyzer aspirations by 2050. Hence the conclusion that RES economics will become increasingly set by and intertwined with the economics of hydrogen. Price formation, price discovery and price assessment of hydrogen will then become a crucial aspect in forecasting the economics of the various building blocks along the new clean hydrogen value chains.

Global demand for hydrogen, including from both fossil fuel and renewable sources is c. 79.5 million tonnes in 2023. There are various forecasts and scenarios for hydrogen demand by 2030 and 2050. Goldman Sachs' most recent base case forecasts a hydrogen demand of c. 130 million tonnes by 2030 (bear: c. 105 million tonnes; bull: c. 160 million tonnes), and c. 190 million tonnes by 2035 in their base case, growing further to 368 million tonnes by 2050. The IEA presented in her most recent global hydrogen review a demand of c. 115 and 130 million tonnes by 2030, while DNV forecasts c. 130 million tonnes of hydrogen production in 2030, growing to c. 175 million tonnes by 2035 and 325 million tonnes in 2050.

The different forecasts of green hydrogen in million tonnes per annum are difficult to compare as each uses different input parameters, like different load factors or efficiency factors. The quoted numbers are highly dependent on the kind of RES taken into the portfolio and their location. To our knowledge, no one is explicitly incorporating geo-political, regulatory, or financing risks, or aspects around price formation into their analysis. Hence input numbers are different for global forecasts versus European ones, which are again different for each country. Moreover, forecasts are sometimes made for clean hydrogen thus green plus blue, and sometimes for green only, which could be confusing as electrolyzers are by definition green, running on RES (although in China there are also electrolyzers running on coal). Hence, total production output forecasts vary materially. But without exception, all forecasts show material cost savings to be made in the construction of electrolyzers in the years ahead, following a similar unit cost reduction path as solar and wind did, but only in half the time.

Goldman Sachs estimates that between 65 and 180 GW of electrolyzer capacity will need to be installed by 2030 under their three scenarios, with a base case of 120 GW. This would translate in c. 16 million tonnes of green hydrogen globally in their base case. Based on their identified funnel of projects under construction, FID and feasibility, they see a cumulative installed electrolyzer capacity of c. 80 GW by 2030, including 27 GW in Europe, 20 GW in Australia, 13 GW in Latin America, 15 GW in Africa, 3 GW in the Middle East and 2 GW in the U.S. (pre-IRA). This ill-compares with the 93 GW what is needed in Europe alone. The 27 GW in Europe by 2030 produces 3.6 million tonnes of green hydrogen, a long way off the 10 million tonnes production ambition.

In the most recent Shell energy scenarios clean hydrogen will grow from c. 10 million tonnes globally to 230 million tonnes in their first scenario (Sky 2050) between 2030 and 2050. In their second scenario (Archipelagos) CCS plays a pivotal role, but total clean hydrogen production stays low, at c. 60 million tonnes by 2050. In the Sky scenario, c. 5.5 million tonnes is green in 2030 and c. 4.4 million tonnes blue. In the Archipelagos scenario green hydrogen is neglectable.

According to the IEA's review, world renewable hydrogen production could reach 16-24 million tonnes by 2030 if all identified projects in their pipeline would be realized. The 16-24 million tons of clean hydrogen is split between 9-14 million tonnes based on electrolyzers (green) and 7-10 million tonnes on fossil fuels with CCUS (blue). Meeting government's climate pledges would require 34 million tonnes of low-emission (green and blue) production by 2030. The difference is mainly because of a gap of 8 million tonnes of green hydrogen. Expected clean hydrogen demand in Europe is c. 14.5 million tonnes by then. The IEA notes that global electrolyzer capacity could reach 134 – 240 GW by 2030. The former would translates in 18 million tonnes of green hydrogen according our own calculations, deviating substantially from IEA's quoted 9-14 million tons of green hydrogen, i.e. a lower supply output per GW of electrolyzer. Later this autumn, the IEA will present a new edition of their clean hydrogen outlook.

Citi sees 5 million tonnes of clean hydrogen production in the U.S. by 2030 and 6.5 million tonnes in Europe.

BP forecasts a demand for low-carbon hydrogen between 30-50 million tonnes by 2030 in their two scenarios, the majority of which is used as a lower carbon alternative to the existing unbated gas- and coal-based hydrogen used as an industrial feedstock in refining and the production of ammonia and methanol – thus a focus on scope 1 and 2 GHG emission reduction. Of the 30 million tonnes of clean hydrogen, about half is green; of the 50 million tons of clean hydrogen, c. 33 million tonnes of supply is green. Thus, resulting in green hydrogen in a range between 15 and 33 GW. According to BP, the pace of growth accelerates in the 2030s and 2040s as falling cost of production and tightening carbon emission policies allow low-carbon hydrogen to compete against incumbent fuels in hard-to-abate processes and activities, especially within industry and transport. Demand for clean hydrogen rises by a factor 10 between 2030 and 2050 in both scenarios, reaching close to 300 and 460 million tonnes respectively.

Finally, DNV presented in its hydrogen forecast 465 GW of global electrolyzer capacity in 2030 producing c. 24.6 million tonnes, of which about 111 GW in Europe and producing 6.6 million tonnes of green hydrogen at the regional operating hours average of 3,000 hours/yr. This is materially more GW of electrolyzers projected compared to the other outlooks. DNV roughly uses half of the hours/yr versus others. Green hydrogen production is forecasted to be about 185 million tonnes by 2050. Europe is projected to become the 2nd largest producer after Greater China with 258 GW in 2030 and c. 11 million tonnes of green hydrogen production. In their outlook (pre-IRA), U.S. green hydrogen production would be a meagre 1 million tonnes in 2030. In addition, they expect c. 20 million tons of blue hydrogen in 2030 and 90 million tonnes in 2050. Grey hydrogen production is in 2030 still as large as today, at c. 85 million tonnes, but by 2050 it should have decreased to 50 million tonnes.

Deloitte recently presented in their 2030 global green hydrogen report that clean hydrogen demand of 172 million tonnes of hydrogen-equivalent by 2030 is needed to achieve net-zero GHG emissions, and 598 million tonnes in hydrogen-equivalent by 2050. This includes pure hydrogen and green ammonia, green methanol and SAF calculated in hydrogen-equivalent terms. This is still twice what DNV projects in their outlook.

The Goldman Sachs' scenarios show that the combined hydrogen demand of 'refineries, ammonia and methanol' is stable and basically equal for each scenario for the coming decades. Together their demand is close to 74 million tonnes of hydrogen. Europe's share was 8.7 million tonnes in 2020. Most of that is consumed in Germany and the Netherlands. In the U.S. demand stands at c. 11 million tonnes. More than 95% of the hydrogen production today is from fossil fuel sources and generate an high amount of CO2 emissions. It are the existing industries which are producing and consuming grey hydrogen today and where the first conversions from grey to clean hydrogen are expected to occur, to start in Europe and the USA. These first developments will concentrate on reducing scope 1 and 2

GHG emissions in those industries. It is more interesting to see how the other industrial sectors and notably hydrogen in mobility is going to develop. The delta between bull and bear cases in 2030 is about 50 million tonnes of demand for all colors of hydrogen globally. Half of that is clean. For what it is worth, by 2050, the delta for clean hydrogen could be as big as 450 million tonnes in that year. In the base case c. 17% of global hydrogen supply will be clean by 2030 and c. 70% by 2050. Nevertheless, in the base case global grey hydrogen supply will be higher in both 2030 and 2050 than today. Thus, while clean hydrogen is a necessary pillar to any aspiring net zero path, the pace and extent of hydrogen penetration is far from certain. Key drivers that ultimately influence the penetration of clean hydrogen are:

1. The price of electricity for hydrogen production.
2. The price of carbon.
3. The commodification, price discovery and price assessment of clean hydrogen and its carriers / derivatives and the establishment of price benchmarks.
4. The CAPEX cost of the electrolyzers, plants, facilities and related infrastructure and the pace of unit cost improvements versus sticky inflation forces.
5. Any further improvement expectations in the electrolyzer efficiency and higher utilization (load factors).
6. The cost associated with hydrogen adoption compared to alternative technologies (e.g. battery electric powered trucks).
7. Returns and attractiveness for investors and financiers.
8. Consistent policy support with long visibility versus policy complexity, market orchestration and interference.
9. Stable and predictable market circumstances without big and certainly unexpected annual variations that cause for volatility.

Pioneering in Big Business Clean Hydrogen Market Dynamics, Price Formation and Price Discovery

An intellectual exploration how markets could develop

III. Introduction

Clean hydrogen has emerged as a critical pillar to any aspiring global net zero path, contributing to the de-carbonization of circa 15 percent of the global GHG emissions. A new focus on hydrogen started in earnest in 2019 although Japan came out with a national hydrogen strategy in 2017 and the oil majors and Japanese car industry are already working on clean (or low carbon) hydrogen solutions since the early 2000s. Over the last couple of years, the intensified focus on de-carbonization and climate change solutions has begun to translate into renewed and intensified policy action aimed at a wider adoption of clean hydrogen. As a result, we now see the first results of convergence around policy, affordability and scalability emerging that should kick off the development of this new industry. Nevertheless, the production of clean hydrogen today is still close to zero and many hurdles have to be overcome to create a profitable business.

Many projects have been announced along the full spectrum of colors of hydrogen. But like in any new capital-intensive business, announcements imply that the engineers, new business developers and today also the ESG policy and permitting experts have been mandated by their leadership teams to start designing the first clean hydrogen projects. But not many projects have been sanctioned, and only one electrolyzer of scale (the Shell 200MW electrolyzer project in Rotterdam) is currently under construction in Europe. Like the early days of the RES industry in the early 2000s as well as the oil industry itself, it takes several years of new business development work before the first Final Investment Decisions (FID) are taken and projects are actually built.

For instance, in the oil industry the shift from the exploitation phase of the 1990s to the next investment phase that started in 2000 when the oil price curve started to rise and gave a strong signal for new investments needed in the upstream business, it still took 4 years before the real CAPEX spend started in 2004 and another couple of years before material new production capacities came onstream. At the same time, from 2006 onwards, industry ROCE started to deteriorate again as costs overruns and delays hit them hard.

In the case of clean hydrogen, we are afraid that this will not be much different. We are now very much in the early development phase. The RES business had even a longer development journey, having celebrated its 2nd 10-year anniversary in 2021, and had its first bonanza between 2013 and 2017. Moreover, RES is a far more straight-forward business, producing electrons that everybody understands and can be simply fed into the system.

Clean hydrogen in that respect is far more complicated because of its long, diverse and fragmented value chains, the variation of hydrogen carriers both in gaseous and liquid state, and the much more diverse playing field, with industrial oil/liquid fuel companies including the large integrated oil & gas companies, refiners and independent tank storage companies, industrial gasses industries, chemical companies, fertilizers and steel manufacturers, RES electricity developers and producers, and pipeline and utility companies, all competing for parts of the value chain, depending on their ability to finance the investment and manage the complex investments and contractual relationships over long distance and time [1].

Current hydrogen production in the European Union (11.5 million tonnes capacity in 2020 with an average capacity utilization of c. 76% in that year) is mainly concentrated in and among industrial clusters in Germany, The Netherlands, Northern France, and Belgium, where about 58% of European hydrogen demand is concentrated. The hydrogen, predominantly made from natural gas and waste gases, is used both as an energy carrier and feedstock in the refining of crude oils into oil products, in petrochemical industries, and in the production of second-generation biofuels and bio-naphtha. In the European Union (EU), hydrogen is an industrial gas and is treated as such in EU trade policy (import tariff).

New clean hydrogen production in the region will be based on electricity generated predominantly by offshore wind and solar.

Although the offshore wind potential in the North Sea is huge, and some countries will be able to export their surplus electricity to neighboring countries, the expectation is that the industrial countries around the North Sea will not become self-sufficient and will have to import additional clean hydrogen from elsewhere. This is also because the introduction of clean hydrogen for industry is planned side by side with electrification. Since 24/7 availability is needed for many industrial users, they are interested in setting up alternative flows in addition to North Sea offshore wind production and H2 conversion. Particularly demand in Germany will have to rely on imports, but also the Amsterdam – Rotterdam - Antwerp (ARA) region in the Netherlands and Belgium, assuming the continued existence of their industrial base, will need to import clean hydrogen carriers [2]. The assumption around demand and particularly the effect of the very worrying de-industrialization of Europe due to high, non-competitive energy prices and high production costs is a serious threat to the ultimate demand for clean hydrogen. It also makes a difference whether the electrolyzer will be system-serving unit and primarily used as a variable and system-serving stabilizer or flexible load, or be an stand-alone unit in the ultimate output throughout the year.

After having lost Russian gas as a (relative) cheap energy source (and certainly competitive versus the alternative of LNG at that time), pertinent high energy prices in comparison to natural gas prices and production costs in the U.S., Middle East and Asia could seriously impact the competitiveness of the industry and could cause a restructuring of EU-based energy-intensive industries producing for world markets. Without doubt, the industry is by far the most important factor in realizing the potential clean hydrogen demand, as they need the large volume to replace current feedstock and energy use. Hence, the extent of de-industrialization will clearly change the potential demand of industry for clean hydrogen. Moreover, these industries are the key enablers for the development of a clean hydrogen economy in the coming decade. The difficult position of the European energy-intense industries is already reflected in the material decrease in gas demand in Europe from 496 bcm in 2019 to an expected annual demand of 421 bcm in 2023 and 447 bcm in 2024 [3]. This could potentially further decrease to 350 bcm by 2030, plus/minus 50 bcm variation to compensate for days with lots or little renewable electricity and good or bad hydro-power seasons.

Moreover, there is a growing and worrying attitude in Brussels to actively support gas demand destruction for climate change reasons, even if this is at the expense of energy security, price affordability and industrial activity. Clearly, Europe doesn't want to bond with U.S. LNG exporters for long-term energy supply. Instead they want to keep them at arm-length and to arrange LNG supply as much as possible through spot sales and short-term contracts. If this would create short periods of tightness with price spikes, so be it. Hence, LNG is not treated any longer as a transition fuel in Europe and needs to be phased out as quickly as possible. The future is clean hydrogen and RES renewables. For these reasons, European gas demand could potentially collapse rapidly in the next decade, if all plans would be successfully realized, and accelerate if the energy-intensive industry would indeed relocate and cause the EU de-industrialize. Those plans are consistent with the wish to become more strategically autonomic. EU strategic autonomy (EU-SA) refers to the capacity of the EU to act autonomously – that is, without being too dependent on other countries – in strategically important policy areas. These can range from defense policy to the economy, including energy, and the and the capacity to uphold democratic values. In the field of energy, this is not any longer only about security of supply, but also about price. After having paid an ugly $ 350 billion to reduce energy bills for European consumers during the energy crisis and Europe having spent c. $ 200 billion on LNG imports paid to 'friendly' energy exporters last year (vs. c. $ 10 billion in 2020 and c. $ 60 billion in 2021), the overarching driver for governments is to never let this happen again and to create an energy system that is abundant, with low, stable (less volatile) and predictable energy prices for consumers. It is their believe that RES additions could work as a deflationary force and, if well regulated, will create good visibility, and thus meet their long-term ambitions in many areas simultaneously. For clean hydrogen, however, they acknowledge that imports have to be developed in the coming years and potential exporting countries are mainly selected on geographic diversity and relations to western countries.

In the Netherlands, Europe's 2nd largest hydrogen user, just one out of 25 companies with plans to develop hydrogen infrastructure in the Port of Rotterdam have started the construction phase: Shell is building a 200MW electrolyser due to be finished in 2025. The other projects are still in the pre-FID development phase. The chief executive of the Port of Rotterdam is promoting that "the port could deliver almost half of the EU's import target but

that the domestic production goals would be “more challenging.“ An overview of the hydrogen activities in the port of Rotterdam is presented in appendix I.
The U.S. is actually behind developments in Europe, but is generally more agile and business conscious than Europe and therefore is expected to catch up quickly. More specifically, we believe the U.S. Inflation Reduction Act (IRA) will be transformational for the hydrogen ecosystem in the U.S. The bill — via the Clean Hydrogen Production Tax Credit (PTC) — is particularly supportive of green hydrogen, meaningfully improving its cost-competitiveness compared to pre-IRA.

What is interesting to note is that this time the governments are more gung-ho and enthusiastic about hydrogen as a key solution to make the energy transition on time and successful, while the industry is still reluctant to proceed. This is contrary to the offshore wind in the early 2010s, when the industry was ready to go, but governments still felt very uncertain given the substantial subsidies that were required to make the projects viable. Nevertheless, we expect renewed confidence on the back of strong political commitment, ESG policies and latest Corporate Taxonomy reporting and legislation. Also, increased shareholder activism brings an inflection point closer. Together with the global political and fiscal support this could potentially be transformative or, at a minimum, supportive for the cleantech and low-carbon value chains, including clean hydrogen. This being said, increasing the use of clean hydrogen as a new energy vector is a long-term endeavor, implying a multi-decade long process to significantly penetrate the energy mix and to decarbonize the harder-to-abate sectors of our heavy industries including refineries & petrochemicals, iron & steel, ammonia and methanol production plants and for high-temperature industrial heating, and for the transportation sectors such as long-haul heavy transport, shipping and aviation. Most importantly, first the mindset of decision makers and key policy makers have to change as the business environment has changed, and is changing a lot. Many reports, studies, and analyses are dated because they are still based on outdated assumptions and input parameters. There is a clear need for a reset of expectations that mark the beginning of a robust up-cycle in capex investments and strongly improved shareholder confidence. But we are not there yet.

There are good reasons for the industry not to become (too) overly enthusiastic given the relative immaturity of this new hydrogen industry, including the state of maturity and cost-levels of the electrolyzers itself, the big uncertainties around construction and infrastructure

Outside Battery Limits (OSBL) costs, the long fragmented and under-developed value chains, the lack of customers and uncertainty of how, when and where markets, value chains and cost levels will develop, the regulatory and policy uncertainties, and most importantly, how price discovery and price dynamics for clean hydrogen and hydrogen carriers will evolve and enable the development of markets. All these aspects are still uncertain, notably the ones around price discovery. In this respect RES solar and wind are relatively easy that it is a simple single product — electrons — that will be produced, and that it could be easily integrated into the power value chain. Moreover, all RES wind and solar projects are at the start of the value chain, in the upstream production sector of the commodity chain, contrary to electrolyzers, which are mid- to downstream. Also, all the electrons are produced locally or regionally, not globally and therefore easier to integrate without having to bother too much about external market forces and influences from other regions. For hydrogen, this is very different and far more complex.

First, clean hydrogen production is like a refinery, a margin business and secondary energy source, not an upstream business or a primary energy source, where in this case electrons are converted into H2 (green hydrogen), or natural gas in combination with carbon capture, utilization and storage technologies (CCUS) is converted into H2 (blue hydrogen). Hydrogen producers are thus one segment located halfway the value chain, generating revenues from sales of hydrogen, with electricity purchases as their biggest cost of goods sold. To make a margin, they have to make big capital investments in units that are expected to become much cheaper in the foreseeable future (something we doubt that this will be the case). To overcome this obstacle (of high costs), there must be a big pull or compensation for the cost difference.

Second, hydrogen can be attractively positioned as a fuel, feedstock or energy source in a number of industry, transportation, power generation and building applications. Yet, each of these markets have different dominant primary and secondary energy sources currently in use and all are confronted with different market dynamics, price formation developments and price discovery methodologies and customs. Generally they are also quoted in different units: in \$/bbl or \$/tonnes, in \$/kg, in Euro/MWh, in \$/MMBtu, where S&P Global Platts, one of the leading independent providers of information and benchmark prices for commodities and energy markets, including hydrogen, quotes hydrogen in U.S. dollars and Euros per kilogram, while for instance markets and pipeline transportation tariffs for hydrogen in NW

Europe will be in Euro/KWh and Euro/KWh/h/year respectively and governments mostly talk about MW, GWs and TWh. Each country developing its own preferred solution will not help to create deep liquid markets. The latter is also true for the definition of a green product and the lack of consensus around this aspect and the uneven development of certification.

Third, the hydrogen market is poised to be set up both domestically (where the green renewable power is produced locally and the electrolyzer 'refinery' is built locally), and internationally for export where the hydrogen first needs to be converted in a suitable carrier — e.g. green ammonia, green methanol, or Liquid Organic Hydrogen Carriers (LOHC) — for transportation to end-markets (where a decision has to be made whether the hydrogen-carrier will be recovered/processed into hydrogen, or stay in its liquid carrier form). This all will take place at the same time and thus will create arbitrage opportunities between different supplier industries and customer markets, as well as between incumbent price markers (electricity, natural gas, ammonia, gasoline, diesel, bunker fuels, and kerosene) and new entrants (green hydrogen, green ammonia, LOHC, HVO and Sustainable Aircraft Fuels (SAF), and green methanol). Moreover, domestically produced hydrogen will be in gaseous state, while import flows will come in liquid state. In how far prospective buyers will give preference to domestic clean hydrogen over imported hydrogen is still a question and will be determined by many factors. Examples of aspect that will influence such decision are for example the market price of the clean hydrogen, the regulatory regime for a gaseous clean hydrogen molecule versus a liquid hydrogen carrier, and how governments will balance the development of domestic production and imported flows.

Fourth, notably consumer markets, but also producers' countries, start from a different angle with respect to regulation, taxation and (financial) stimulus policies, law, decrees etc. Most of this is still in its infancy and needs to be further formulated and subsequently adjusted while we learn. Moreover, the European Commission (and the national TSOs) have a natural preference to treat all clean hydrogen as a gas with strong regulation policies attached to it, while imported clean hydrogen will land as a liquid in a far more liberal market-oriented structure. Exporters of clean hydrogen will ultimately opt for the best consumer market. In the initial phase they are likely go for bilateral arrangements with financially strong individual buyers. For countries like Australia, Saudi Arabia, and Oman their natural market seem to be in Japan or South Korea, not Europe and for Chile California makes much more sense. It is to be seen how much clean hydrogen will be locked in in the coming years and will flow to Europe under long-term sales and purchase agreements or will come our direction through spot sales.

Fifth, and most importantly, hydrogen and its carriers must be competitive, both versus the incumbent energy sources and fuels, and relative between regions. Here, Strategic Autonomy is the buzz word. It must avoid de-industrialization, support near-shoring, stimulate new investments for jobs and profits and make regions less dependent on external market forces that impact security and affordability. With respect to imports, it must come from a diverse portfolio of different friendly countries. This all needs to be done in a context where governments want to balance the development of domestic production and imported flows of clean hydrogen, have a strong say in the regulation of markets, will monitor transparency to foster a liberalized market orientation, and preferably develop institutions which function well, are uncontested and politically neutral. It must also avoid preferential treatment. But what has grown most in importance to them, the European countries, is to be never ever confronted with another big surprise of energy price spikes as happened last year again, which came (for them) completely out of the blue. Instead, the overarching goal is never ever to be unexpectedly confronted with unpredictable high and volatile prices for consumers, or allow any player to have a dominant position along the value chain. Hence, the climate policy objectives of the energy transition have been expanded with additional overarching goals to get cheap, predictable, and stable energy prices with long-visibility for all stakeholders. This key objective could result in a situation where the European Union develops increasingly more into a more corporatist state where member-states will aggressively redress the balance between the state and the market, put strings around open market price discovery processes (at least for retail markets), and basically try to tame or even undo the functioning of commodity markets. At the same time, the U.S., with its far more pragmatic regulation and much more business friendly policies and interests, might start to compete with Europe for the same clean export molecules one day, while also become an exporter if the circumstances are there. In any case, during these periods of structural change with more government regulation, intervention and orchestration for strategic reasons, it will create new realities and start new trends. How European and foreign commercial companies will respond to these new trends is unclear. Only when the domestic and imported volumes grow to a more substantial size, more clarity will exist on how these new markets will work and what regulatory regime fits best.

Given the broad range of end-uses and markets for clean hydrogen and the increasingly stronger societal demands to fast track lower scope 1, 2 and 3 GHG emissions, the overarching key factors that will ultimately influence the penetration of clean hydrogen are (i) the level of policy support and financial aid to the industry, in the same fashion this has been done for offshore wind in the 2010s, (ii) the cost associated with hydrogen adoption compared to alternative technologies in each of the aforementioned industries and sectors, and (iii) the (speed of) development and inter-dependence of each segment along the clean hydrogen value chain from energy production source to end-customer markets, in such a way that industries can de-risk their projects to make them successful. In that respect, we are fortunate to have an oil & gas industry that has decades of experience in setting up comparable value chains through orchestration in the LNG space and have the means to make it happen. At the same time, it is to be seen in how far they can replicate this business model under the current set of rules and laws and are allowed to orchestrate profitable value chains.

In this working document, several of these aspects will be analyzed in the following chapters. Some aspects are backward-looking and give oversight and insight how relevant sectors have developed over time. Others are more forward-looking and are absolutely open for debate and therefore more an intellectual exploration.

The first chapter describes the various value chains for hydrogen currently under development and in which sectors clean hydrogen will make their inroads. This chapter sets the scene for further analysis in the following sections.

The second chapter presents the results of a two year study on an advanced design of a 1 GW green hydrogen plant to be operational in 2030 including CAPEX cost estimates.

The third chapter describes at a high-over level the evolution of the RES market from 2000 onwards, and how this is likely to develop in the coming decade and how it will potentially enable the development of a hydrogen industry and markets.

In the fourth chapter a number of outlooks and scenarios for clean hydrogen are presented, as well as the latest targets for Europe.

In the fifth and final chapter we will make deep dive into price formation and price discovery and the establishment of a hydrogen exchange in the Netherlands, building on the successes of the Amsterdam Power Exchange (APX) established in 1999, and TTF, the Dutch gas trading platform, launched in 2003.

This report will not describe the hydrogen-related regulation and governmental policy and law-making aspects in detail, as this is a process in constant flux and development, and only touches the geopolitical aspects of hydrogen.

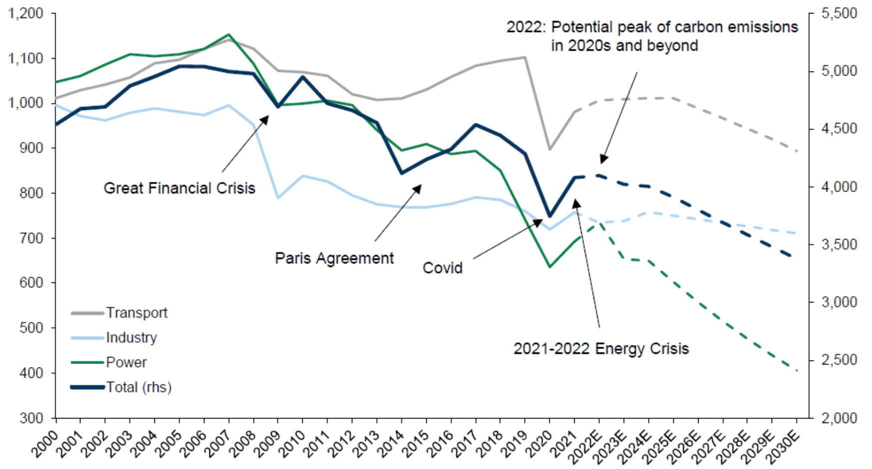
The report has been written from a New Business Development (NBD) and a traders' point of view. It expresses the view of the author, who has 40 years of experience in NBD, M&A and the financing of all type of big energy projects around the world, and in commodity markets.

In this report the focus is on Europe, with many references to the Netherlands / Northwest Europe. In GDP terms, the Netherlands with a GDP of c. Euro 1 trillion would be the 5th state of the U.S. after California, Texas, New York and Florida. It would also be 5th state with respect to number of citizens. In size, however, the Netherlands is a small country, no 133 on the list of countries and 3.4x smaller than the state of New York. Moreover, the Dutch part of the North Sea is c. 1.5x the size of the Dutch land. The Netherlands is home to Europe's largest seaport, the Port of Rotterdam, located at the North Sea and in the Rhine-Meuse-Scheldt delta. With its deep-water port and convenient location, connecting international waters with Northwest Europe, the Port of Rotterdam functions as a global hub for international energy trade. The Port of Rotterdam plays an important part and is embedded in the Antwerp-Rotterdam-Rhine-Ruhr-Amsterdam Area (ARRRA), a petrochemical cluster that generates 40 per cent of the total petrochemical output in the European Union. Significant quantities of energy, among others in the form of crude oil, oil products, coal and gas are imported through Rotterdam daily, and transported via river barges and pipelines to industrial clusters located in Northwest Europe. The Netherlands is in a strong position to make a significant contribution to Europe's low-carbon hydrogen market thanks to its current role as a European energy hub, substantial chemical industry, favorable geographical location at the North Sea, huge offshore wind potential, the world's large penetration of solar per capita, and existing gas and oil infrastructure. With an estimated 1.5 million tonnes per year, the Netherlands is the second largest hydrogen producer in Europe, after Germany. A comprehensive overview is given in the RIFS (Research Institute for Sustainability, Potsdam) / CIEP Discussion Paper: The Netherlands as a Future Hydrogen Hub for Northwest Europe. Analyzing domestic developments and international engagement. April 2023 [4].

There are six well-defined colors of hydrogen, depending on the production route and technology, ranging from traditional fossil-based hydrogen to clean hydrogens. In this report we primarily focus on the green hydrogen production route, and only sporadically on the blue one.

Finally, there is a very good reason to make all these efforts: to rapidly lower carbon emissions. On average, Europe was able to decline carbon emissions for -2% per annum between 2005 and 2020 (Exhibit 1). However, between 2020 and 2022, carbon emissions increased +9% driven not only by a sequential increase in mobility post-COVID-19 pandemic, but also by significant gas-to-coal switching in the power generation section [5]. Specifically, tight European gas markets drove natural gas prices well above coal, intensifying generators to increase their use of coal versus gas. The accelerated RES expansion in combination with the first roll-out of green hydrogen production must result in a resumption of the downward trend of the 2010s, only now at a faster pace. It is a sad observation that also this year we will see an all-time high in global oil demand, natural gas demand, coal demand and GHG emissions. So far, RES only has contributed to the annual global additional energy demand, but has not triggered a decline in global demand for fossil fuels and resources. While the EU has seen a slow, but volatile decline in carbon emissions since 2000, the cuts were not enough to neutralize the rise of carbon emissions in the developing world (where most of the people live, the highest growth in population and economic development takes place, and where this growth is more fostered by growth in industrial activity than in services).

Exhibit 1: EU carbon emissions with GSe after 2022, total and key sectors, mt CO2e



Source: Eurostat, EEA, IEA, Haver Analytics, McCloskey, Goldman Sachs Global Investment Research

More CO2 emission data is presented in appendix II.

1. Chapter 1

1.1 The various value chains for hydrogen

The clean hydrogen ecosystem encompasses a wide range of corporates across the various value chains under development. These corporates include the RES power producers, incumbent utilities, large-cap integrated oil & gas companies, midstream power grid and pipeline companies, storage companies, either state-owned, private or publicly listed, and the new entrants pure-hydrogen players focusing on the production of green hydrogen through electrolyzers, as well as application players across all hydrogen end-markets (industry, transport, power generation, heating). The realization of the various value chains are then supported by the Original Equipment Manufacturers (OEMs) and contractors, consisting of industrial companies and conglomerates with rising exposure to the hydrogen theme as well as new pure-play companies. To complete the list, the industry needs financiers and investors.

Together, these companies and their financiers are developing value chains that can be broadly split in domestic-based clean hydrogen value chains and export/import-based clean hydrogen chains. Each of these two categories will have very different cost profiles, corporate and government involvement, interdependencies, and most likely a different customer base and thus purpose. This also implies that they most likely involve different price formation and price discovery aspects, and thus risk profiles.

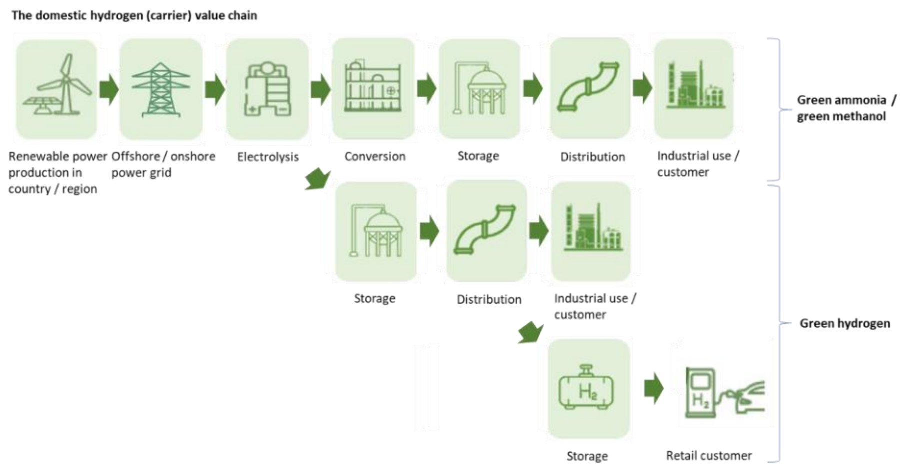
Like in the LNG space, clean hydrogen value chains are long and complex. In the first 50 years of LNG, before the arrival of U.S. LNG in the mid-2010s, the value chains were nicely (and tightly) knotted into strict vertical virtual value chains, where interdependence between corporates along the value chain were managed through classic legal long-term contracts and cross-ownership in various key segments of the value chain. Given the long-term nature and multi-billion dollars at risk (generally, LNG projects are the most expensive commercial projects in the world), the projects could only flourish in high-trust environments. High trust was, and still is, a prerequisite for the sponsoring companies, the financiers, not only amongst them, but also in governments, legal, fiscal and political systems, and in OEMs and contractors to deliver – on time and within budget. With a minimum of like-minded parties involved along the value chain, through classic contracts risks (today and in the future) where precisely allocated and shared where needed. The same was done with costs and benefits, and all in such a way that most profits and the best profitability profile felt with those companies who bear most of the risks, that each risk was allocated to the most natural owner of such risk, and that each risk could be taken by such company from a managerial, technical, organizational and financial point of view. This was all achieved through negotiated transactions on a bilateral basis, where parties selected each other to join the project. Outright auctions and competitive bidding were avoided because governments want to hand-pick the sponsors for those very strategically important projects and not to end up with inferior companies or ones they had less trust in or came from a the wrong country.

Since the early to mid-2000s, the LNG business started to experiment with less tightly knitted value chains. Market pressure and new government regulation demanded more contract flexibility, resulting in the gradual end of destination clauses, new forms of pricing of LNG and thus contract terms and conditions, including a variety of contract tenors, the start of exploiting arbitrage opportunities between regional markets, and the arrival of LNG aggregators starting to further optimizer global supply with global demand. This process was initially still predominantly managed by the incumbents. With the arrival of U.S. LNG in 2016 and new entrants – the global commodity traders, such as Vitol, Trafigura and Gunvor – , the liberalization of the global LNG markets accelerated, resulting in new value chain models and supply and demand dynamics. This has further evolved to the current position we are in.

The future clean hydrogen market will be built on the current models used in the LNG market, where the gas supply will be replaced by the supply of electricity produced from solar and wind. However, given that this is a completely new market, early participants might have a preference and tendency to orchestrate the clean hydrogen value chain in order to manage and mitigate risks along the chain. Hence, the hydrogen market will not start where the LNG business is today. The clean hydrogen market is far too immature and uncertain for this. Governments do not seem to realize this (yet). Like the LNG industry had to go through several phases of development, this will be equally true for the emerging clean hydrogen markets. Moreover, the LNG value chain was always fully understood and developed by the same group of players, the major oil and gas companies and a handful of contractors. In the case of clean hydrogen, the corporate ecosystem encompasses a much wider range of corporates across the entire value chain than in LNG. Also have the regional electricity markets evolved differently than the oil and gas ‘molecules’ markets. These two now have to find each other, to create the best starting point for a successful development of the clean hydrogen market.

The domestic-based clean hydrogen value chain category looks schematically as follows:

Exhibit 2: The domestic hydrogen (carrier) value chain



The chart clearly shows that the chain is long and potentially fragmented, consisting of many individual building blocks, and with many variations and optionality to select from. Moreover, governments in Europe have organized the institutional framework in such a way that part of the chain is state-owned and state-led, generally in line with long-term infrastructure planning procedures and policies, and part by commercial companies having the mandate from shareholders to create new profitable businesses. Moreover, both groups – state-owned and private or publicly-listed commercial companies – will have different positions along the value chain, where each building block of one group is directly interfering with the other group: The offshore / RES power production facilities will be owned, developed and operated by commercial and generally listed companies (although in many cases governments have a major shareholder interest in those companies, at least in Europe). Their electricity output is sold on commercial terms. The decision to build those RES power production facilities is dependent on the risks they have to take and which could be transferred to others along the value chain, how the revenue pie of the value chain is split over the participants, and in how far they are forced to take price risk (like oil and gas producers) and how that risk is shared with others along the chain. Being at the end of the $-chain that started with the payment by end-consumers, for them fully understanding the value chain and price dynamics and to have long-term visibility over the life-time of the project is key for deciding to participate in the endeavor.

The next building block along the value chain consists of the offshore and onshore power lines. In Europe, these are generally owned by state-owned or Utilities' owned TSOs. Those companies facilitate the shippers of electricity over their net. The associated costs are socialized and regulated. Some RES developers see opportunities in producing the clean hydrogen offshore to avoid the construction of offshore power cables and to use converted gas pipelines for transporting hydrogen.

The next building block is the electrolyzer (and eventually the conversion plant in case the hydrogen is converted into a hydrogen derivative or used as a fuel for the production of high-valued clean products such as renewable diesel and sustainable aircraft fuels (SAF). These plants will again be owned, developed and operated by commercial companies. They will purchase the electricity from the wind farm consortium, convert the electricity into hydrogen (and eventually into a green hydrogen carrier), and sell the product to their marketing and sales organizations on commercial terms who will on-sell it to end-consumers (or sold directly to the captive end-user inside their organization). In that sense, commercially it is comparable to oil refiners, where operators make a gross refinery margin (set by the delta in sales prices of the crude oil cocktail and the oil product slate). If the ultimate buyer is not directly located adjacent to the electrolyzer plant, the hydrogen needs to be transported through a hydrogen pipeline network (in case of gaseous hydrogen) owned and operated by a state-owned or regulated infrastructure company. Again, the CAPEX and OPEX costs are socialized and regulated. In case of green ammonia or methanol, it is expected that these pipelines will be owned by commercial companies under another regime. Assuming the hydrogen is shipped by the seller, the molecules at the end of the pipeline are owned by the shipper – a commercial company – who will then sell the hydrogen and transfer ownership of the molecules to the ultimate buyer. Again this will be done on commercial terms. The price for the hydrogen will then generate the revenues that needs to be shared with all the players along the value chain all the way back to the owners of the first building block, the offshore wind / RES power producers. The price of the hydrogen (probably in $/kg) has probably not much to do with the price of electricity (in Euro/MWh), and while the buyer will know the sales price of hydrogen, he will not know the price of the electricity used for the conversion (besides an indication of wholesale prices as per exchange). Of course, the biggest question will be who will become the biggest beneficiary and will own the profit zone (if there will be one), able to set the price and capture most of the value.

Due to this fragmentation the risk profile is high, especially during the initial phase of development when nothing is in place or has been crystalized. Due to its nature of a large capital-intensive business, the risks have to be assessed over a very long period – decades not years. In other words, investors heavily demand good visibility and predictability over the full economic and technical life of the assets, individually and collectively along the value chain, generally organized through big classic legal contracts. While getting a full understanding about the risks involved during the permitting, development, construction, and operations phases is already an immense task, to negotiate them and to achieve agreement on those normally takes years (and have a high percentage of failure), especially when each building block consists of different entities (and potentially with different objectives, risk appetite, return expectations and risk absorption capabilities). In such case each entity (or consortium of entities) will ultimately strive for the maximum piece of the revenue pie, and for the minimum level of risks to bear. At the same time, each party in question will try to transfer as many risks as possible to his counterparts at both sides in the value chain. But ultimately, the risks passed on to the others will generally stay inside the value chain, and result in credit risk each player has to take on the others involved. To make it work, risks have to be transferred to someone else outside the value chain, either to parent companies, insurers, ECAs or governments who will have to provide corporate parent guarantees, insurance, or subsidies and funding respectively. Alternatively, companies might only want to be involved if they can orchestrate the total value chain into an integrated hydrogen hub to serve industry and heavy-duty transport, anchored on the company's own captive demand, particularly those companies with a strong LNG background. For them the aim is to replicate the way the global LNG value chains were developed since the 1980s before the U.S. conquered the LNG market in 2017 and reinvented the way LNG is now traded. But this will require negotiated deals, something that is not allowed under European anti-competition law. As a result, companies interested to develop large scale inter-regional clusters and to serve international demand through an expanding hydrogen backbone network will be frustrated by the uncertainty to ultimately win several gigawatt's of offshore wind in a single auction. As long the outcome thereof is uncertain, the development of all the other building blocks further downstream will be confronted with delays and higher costs, while potential customers are forced to take a wait-and-see approach until these inter-dependencies have been satisfactorily resolved. A big question is thus how realistic it is how fast such large international clusters will materialize, especially if governments are actually the true orchestrator of such value chains by setting the terms and condition under which commercial companies must decide to bid, and to take Final Investment Decision (FID) on their parts of the value chain.

In the initial phase of development, say until 2030, the focus is therefore expected to be on building capabilities and serving own assets as anchor demand in local hubs. It is foreseen that clean hydrogen, thus green hydrogen as depicted in the above exhibit 2 as well as blue hydrogen produced domestically, will not be converted into any green hydrogen carrier, but solely deployed as a low carbon feedstock or fuel in energy-intensive industrial processes (i.e. the 2nd line in exhibit 2). There might be some piloting in the mobility sector during this initial phase, but volumes are expected to stay small. The initial focus will be thus on supporting hydrogen as low carbon feedstock for refineries, petrochemicals and fertilizers, while enabling hydrogen in high value end uses such as mobility. Of course, small-cap entrepreneurs could build decentralized small-scale green hydrogen solutions (5-20MW range), and if many will be successful, in aggregate they might add up to something tangible by 2030.

During this phase the sponsors of new clean hydrogen developments are generally also the customer of the clean hydrogen, at least in Europe. They do so to reduce their scope 1 and 2 GHG emissions. The sponsors are generally the large industrial companies who currently use grey hydrogen in their refineries and petrochemical plants. For them it is a 'must do' proposition to protect the life-time future of their plants. Rejecting to do so basically means a decision for early retirement once new legislation, enforced by society and government, kicks in. But there is a good change that those companies will still postpone their investment decisions as long as possible until hard-economics (around natural gas and CO2 prices) and / or regulatory forces force them to take a decision. It is expected that this European rule-based mandatory transition will be gradually accepted and copied by other governments, first in the OECD countries and those who can afford it and then slowly by the other industrial countries in the emerging markets.

A good example of such a 'mandatory' investment is the close to $ 1 billion 200 MW electrolyzer of Shell currently under construction, the first big electrolyzer project that has been endorsed in the Netherlands. Negotiations for a Euro 150 million subsidy under the European Union's IPCEI (Important Project of Common European Interest) programme are still ongoing. The electrolyzer will produce up to 60,000 kg of clean hydrogen per day. The design is based on ThyssenKrupp Uhde Chlorine Engineers-supplied large-scale 20 MW alkaline water electrolysis modules. The electrolyzer will supply the Shell Energy and Chemicals Park Rotterdam including its Pernis refinery complex. The renewable power for the electrolyzer will come from an 759 MW offshore wind farm in the North Sea, which is also partly owned by Shell and will become operational by the end of 2023. Transport between the electrolyzer and the refinery will go through a new hydrogen pipeline in the Port of Rotterdam, which will form a part of the Netherlands hydrogen infrastructure currently rolled out by state-owned gas company Gasunie (through its subsidiary Gas Transport Services (GTS), the Dutch Transmission System Operator (TSO). The green hydrogen will replace some of the grey hydrogen usage in the refinery. This will decarbonize the facility's production of energy products such as petrol, diesel and jet fuel (i.e. reduce scope 1 and 2 GHG emissions). Shell envisages that once heavy-duty trucks are coming available to market and refueling networks grow, clean hydrogen supply will also be directed toward these through their fuels station network to help decarbonizing commercial road transport. As noted earlier, this is expected to be small in the early years. Moreover, Shell needs far more clean hydrogen for its industrial sites in order to meet a -45% scope 1 and 2 reduction compared to 2019 levels by 2030 as enforced by Dutch court in 2021 (pending the appeal later this year). An artist expression of the electrolyzer plant is shown in exhibit 3. The information and data of this project and the others presented further below is to be found at their respective company's webpages or presented in public presentations.

As mentioned, Shell will purchase the electricity from its joint venture company (together with its long-term partner Eneco, an utility) wo owns the offshore wind farm. The supply contract is confidential. The green hydrogen is sold to its own fully owned downstream refinery company. Against what price and terms is confidential. The costs of purchasing the green hydrogen will be part of the total refinery operations cost and be reflected in the wholesale diesel and gasoline price. CO2 cost savings have to be deducted. It will be impossible to find out how much of the gasoline or diesel price at the pump has been impacted by the green hydrogen component. As a result, no price discovery has taken place and no price information will be known outside Shell. Hence, as long as all green hydrogen is captive the project will not help to create a liquid hydrogen market or help the price discovery and assessment process. Moreover, Shell has minimized fragmentation risk by keeping as much as possible under one roof. We have understood that CO2 prices and price forecasts are a key input parameter that have led to the decision to build this plant.

Exhibit 3: An artist impression of the Shell Holland Hydrogen I 200 MW electrolyzer currently under construction

This 200 MW project, dubbed Holland Hydrogen I, is building on the experiences gained from an earlier 10 MW demonstration project (REFHYNE) executed on their Rheinland refinery in Germany between January 2017 and July 2021. FID was taken in December

2017. Construction started in June 2019. At that time the total investment was estimated at Euro 16 million, of which the European Fuel Cell Hydrogen Joint Undertaking would contribute Euro 10 million, and Euro 6 million would be contributed by the REFHYNE consortium with Shell, ITM Power, SINTEF, thinkstep and Element Energy. Construction of the new plant, which features advanced polymer electrolyte membrane (PEM) technology, was expected to be completed in the second half of 2020. The plant will produce up to 1,300 tonnes of hydrogen per year when operating at peak rates. It will replace a small part of the grey hydrogen used in the refinery. The actual start of operations took place in July 2021. Announced costs increased to 22 million Euros. Unclear is whether this include all Outside Battery Limits (OSBL) costs. Some of the key learnings so far as presented by Shell in May 2023 are:

- It is important to be ambitious but agree realistic timescales for a first-in-kind project.
- It is important to acknowledge that future projects will also be first of their kind.
- Building a collaborative cross-functional team including all necessary disciplines from all participating companies is essential for success.
- Up-scaling of all system elements was necessary which had not be done before and required significant work.
- The number of hours where power in Germany is cheaper than natural gas + CO2 would have limited the utilization factor of the electrolyzer operation to only 10% in 2021 (Exhibit 4).
- In addition, between mid-2021 and April 2022 an increase in price delta between electrolyzer H2 and natural gas-based SMR H2 has been observed (Exhibit 5).

Exhibit 4: Hours of green vs grey hydrogen costs

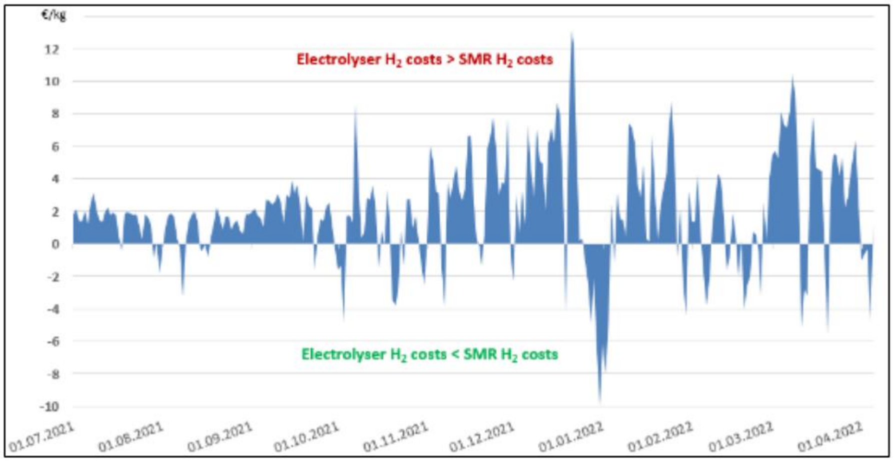
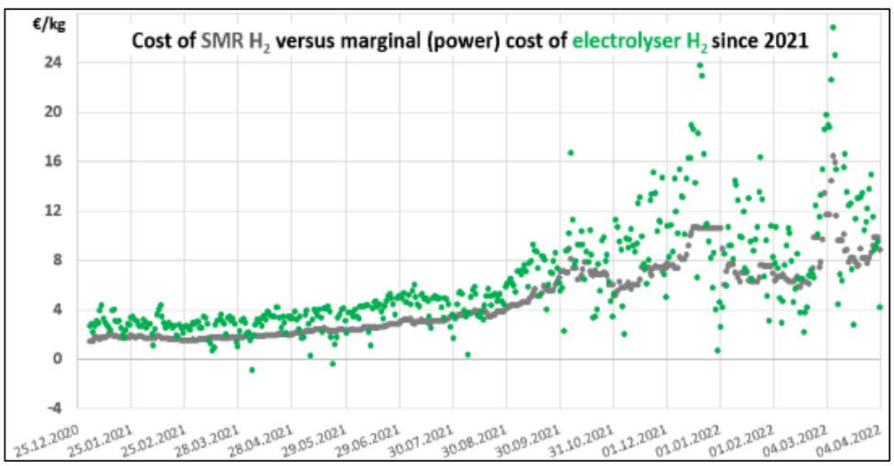


Exhibit 5: Price delta between electrolyzer H2 and natural gas-based SMR H2



A comparable project to the Shell 200 MW project in Rotterdam and that is close to final investment decision is a 250 MW electrolyzer which is currently developed by BP for its Rotterdam based refinery, together with HyCC, a dedicated green electrolyzer development company backed by the Carlyle Group and Macquarie Group. This plant will produce between 55,000 and 83,000 kg of clean hydrogen per day (20,000 to 30,000 tonnes a year of green hydrogen). Also, this plant will take its power from a wind park in the North Sea.

In both cases the clean hydrogen is for captive use. Hence, there will no (external) price assessment take place. Both the renewable power purchase costs, bought from an offshore wind farm consortium — in which the electrolyzer company could participate, as is the case for Shell's first clean hydrogen electrolyzer —, and the electrolyzer's related costs to produce the green hydrogen will ultimately be 'socialized' in the cost of the end-product, in case of the refinery in the cost of gasoline, diesel or jet fuel. Only when the hydrogen will be redirected and sold in the commercial heavy transport sector, a hydrogen price formation and discovery process will potentially take place. Thus, when the clean hydrogen is for captive use, it is highly unlikely that the power purchase price and the hydrogen price will become publicly known, and in how far it will have price uptick for ordinary gasoline or diesel remains to be seen. Basically, the same is true if the hydrogen is sold to a couple of industrial users on a bilateral basis.

In the same spirit, it is foreseen that Tata Steel will develop its electrolyzer in a comparable way as BP is doing in order to reduce its GHG emissions at its IJmuiden Steelworks in the Netherlands. However, the ultimate decision will be taken by the headquarters in India who must decide about the future of the big industrial complex.

In addition to these sponsor - producer type of clean hydrogen developers, there are also companies such as Ørsted that will expand their offshore wind business through forward vertical integration into hydrogen production and basically follow the same route but will sell their green hydrogen production directly to third party industrials, which give preference to purchase the clean hydrogen from a reputable supplier instead of producing it themselves for captive use. Ørsted is (amongst others) the owner of a 752 MW offshore wind park in the Dutch North Sea and is currently developing a 100 MW electrolyzer project with Yara as potential off-taker of the green hydrogen for ammonia production at its world-scale fertilizer plant in the Netherlands. The project hopes to take FID soon. It is possible that Tata Steel will also opt for this route, but as said before, a decision how and by when to bring GHG emissions down is still under investigation. From a pricing point of view, there will be no difference compared with what has been said before. Also, for these projects it is highly unlikely that the power purchase price and the hydrogen price (formula) will become publicly known. The costs of the hydrogen will be part of the cost of goods sold and ultimately reflected in the setting of the sales price of the end-product. Like as is the case for Shell, all these companies are foremost interested to lower their scope 1 and 2 GHG emissions, pressed by government, NGOs and courts to act.

A slightly different route in the development of hydrogen is taken by Air Liquide, a large producer and supplier of industrial gasses to industries. They are developing a 200 MW electrolyzer in Terneuzen (ELYgator) and a 200 MW electrolyzer in Rotterdam (CurtHyl). In both cases, the hydrogen will be transported to its clients in the ports through its own existing pipeline system. Air Liquide also sees a market for itself as a producer of clean hydrogen for the transport sector. The target date for the first electrolyzer to become operational is around 2026/2027 and the other in 2027. For both projects the electricity will be purchased from an offshore wind park owner. Air Liquide has thus opted to focus on its core strength in the downstream segment of the value chain and to leave the electricity production to others. The Terneuzen electrolyzer with an annual output of 170 million m3 hydrogen will combine two different electrolyse technologies — the Proton Exchange Membrane (PEM) process and the Alkaline process. The hydrogen in Rotterdam will be produced through a Proton Exchange Membrane (PEM) process. Please see the next section about the two dominant electrolyzer technologies. Through innovative use of technologies, the ELYgator project makes virtual storage of electricity possible during days when the TSO foresees weather related shortage of solar or wind power resulting in instability on its power grid.

Uniper, a German energy company, is working on a 100 MW electrolyzer in Rotterdam, as part of its ambition to have a carbon-neutral portfolio by 2035. The PEM technology is to be delivered by Plug Power, a U.S.-based OEM in the hydrogen space. The plant is targeted to produce green hydrogen by 2026. Uniper wants to rapidly expand the initial 100 MW capacity to 500 MW by 2030 at the latest.

Finally, since early 2018, SkyNRG is developing a SAF project that will purchase the green hydrogen (up to 6,000 tons a year) from HyCC, which will build a dedicated 40 MW electrolyzer. The electricity will be bought from an offshore wind farm. Latest information is that the companies are working towards FID in 2024, and that bank financing is still pending. Environmental permit approval was received in 2022.

At the end of last year, seven companies in the Netherlands, including most of the mentioned companies hereabove, have received a subsidy of almost Euro 800 million under the 2nd wave of the European IPCEI (Important Project of Common European Interest) programme. If all seven projects with an aggregate power capacity of 1,150 MW will be completed in the coming years, more than a quarter of the Dutch 2030 clean hydrogen target will be met. Developing projects in the Netherlands is difficult these days because of long permitting processes (12-18 months) and uncertain outcomes due to the environmental assessment studies that needs to be conducted as part of the permitting approval processes. Notably the national unresolved nitrogen issues frustrate many projects and cause for severe delays. It is therefore possible that a breakthrough on those issues will accelerate the number of FIDs and will cause an acceleration of clean hydrogen developments.

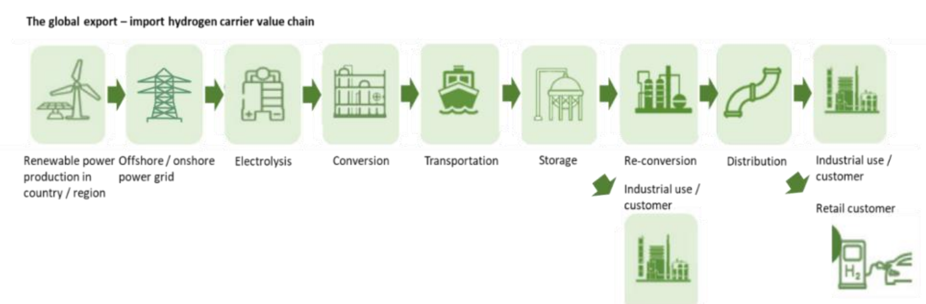
In the next decade it is expected that electrolyzers will not only be built on land, but also offshore (and thus create a slightly different value chain compared with what is presented in exhibit 2). In the Netherlands, the Dutch government has designated an area for what will become the world's largest offshore hydrogen production project. The selected area was already identified for offshore wind development and is now deemed most suitable for providing 500 MW of electrolysis capacity and for the transport of hydrogen to land, where it will be connected to the hydrogen backbone pipeline network. The project, which is said to mark the first application of offshore hydrogen production on a large scale, is planned to be operational around 2031. By then, it also anticipated that the focus will not only be put on scope 1 and 2 GHG emission reductions but will be gradually expanded to the mobility sector to reduce scope 3 GHG emissions in the long-haul heavy transport sector and in the application of hydrogen to produce sustainable aircraft fuels (SAF). Actually, the first clean hydrogen projects for serving the transport sector might already be commissioned before the turn of the decade.

By producing the hydrogen offshore and making use of existing natural gas pipeline infrastructure can ensure a supplementary offshore wind build out without the need for power transmission infrastructure (a serious bottleneck). Not being constrained by the long-term infrastructure planning of TSOs, such developments could accelerate the general buildout of offshore wind. For this reason, in Germany, a large group of international offshore wind and hydrogen developers and organizations have called on the federal government to set clear targets for offshore hydrogen production in their update of the country's National Hydrogen Strategy. The companies and organizations have specifically requested for an additional 10 GW of offshore electrolysis capacity to be added by 2035. For comparable reasons, Ørsted has recently suggested in its most recent advocacy paper that governments should allow vertically integrated, market driven, developer-led developments with a specific industrial scope, where the wind farm is connected directly with the electrolyzer outside the TSO operated grid 6. In such a case, governments only have to designate sizable development zones, where the winning consortium of developers will take full responsibility for the vertically integrated, off-grid offshore wind — hydrogen value chain. Although not explicitly mentioned, it suggests a negotiated deal.

In addition to the domestic-based clean hydrogen value chains currently under development, governments are also seriously promoting the development of clean hydrogen production in friendly countries with favorable solar and wind profiles and low domestic demand for the hydrogen. This has resulted in a string of signed Memorandum of Understandings (MOUs) between European governments and prospective countries around the world. Each MOU must create friendship bonds between both countries and their desire to strengthen the cooperation in energy, particularly on clean hydrogen and the facilitation of international supply chains linking both countries. Such MOUs has been signed with e.g. Canada, Australia, Oman, Saudi Arabia, Chili, Curaçao, Morocco, Namibia, Portugal and Mauritania. In addition, the Netherlands and Spain are cooperating closely to develop a world-scale green hydrogen value chain between both countries. Both Spain and Portugal will thus also become important exporters of clean hydrogen. In addition, China, like in RES manufacturing (batteries, solar panels, and wind mills), is now expanding heavily in manufacturing electrolyzers and clean hydrogen equipment, and is aggressively executing its dual circularity strategy in the RES, BEV, and clean hydrogen spaces both for domestic markets and export markets. In overseas markets, it wants to build dominant positions, generally by building scale and to become the most price competitive supplier or solution provider. Those with privileged RES positions, having deep (financial) pockets, notably Saudi Arabia (Neom project), and a strong will to make it happen, will definitely become the first word-scale clean hydrogen exporters in the world. Others, however, will be very dependent on the rich importing countries for basically everything, ranging from project management, engineers, contractors, labor to most importantly, funding. The right business environment to take business decisions and not been frustrated by too much day-to-day government involvement and politics around capturing future rents upfront and other short-term political objectives is a pre-requisite to attract western developers. The jury is still out, which countries can create the right environment to realize their ambitions, and which will be stuck by internal politics and risk profiles which are far too high for commercial developers and financiers to touch. In that sense, the signed MOUs are basically expression of friendship documents with little substance. Of course a good starting point, but this needs te be followed up with real new business development, executed by world-class companies that have track-records in having developed comparable multi-billion dollar projects in emerging markets successfully. Such companies will only become interested if the funding is firmly available and the right legal structure and regime is in place before they become serious. Many of the governments in question do not have (access to) funding. At the same time, the rich countries will have difficulty to subsidize foreign projects, as their citizens will give preference to see that money being spent at home (including on the energy transition at home). Hence, a lot has to come from (large) commercial companies, the World Bank and other multilateral development banks, ECAs and capital markets to make it happen.

Such export – import-based clean hydrogen value chain category looks schematically as follows:

Exhibit 6: The Global export – import hydrogen carrier value chain



The building blocks are in principle not different then for the domestic-based clean hydrogen value chains other that you need deep-sea vessels for seaborne transport of the (converted) hydrogen. The over-arching driver to develop overseas clean hydrogen production comes from the fact that Europe needs more hydrogen to decarbonize its industries and transport-sector than it can realistically build and produce for itself within the given timeframe. Irrespective of having to deal with comparable building blocks, each overseas project will have its own characteristics and accompanied risk profile. Unfortunately, about half of the selected producer countries does not have any track-record in developing and building such big integrated wind/solar into hydrogen (carriers) projects, nor having a fiscal, legal or regulatory infrastructure that supports such development or a credit rating that make funding of such projects in the international capital markets easy. It might not even have adequate port facilities in place or a large pool of professionals which are needed for the construction and operations phases. Basically, in many cases, they start from scratch. Only the incumbent oil and gas companies have experience in setting up completely new sites, project management and in managing the logistics to give such multi-billion projects a chance of success. On top of this, many of these sovereigns are below investment grade, and thus highly dependent on (cheap) funding from their counterparts in Europe and elsewhere. It is therefore to been seen how fast these ambitions will turn into real projects.

The signals that big oil and gas companies appear to be scaling back their renewable energy businesses or at least are testing their strategies whether they are financially sound and meet their investment criteria will not help either. Also, the fact that they have plenty of opportunities at home and first want to focus on building capabilities and serving own assets as anchor demand in local hubs, make many of these export – import projects uncertain to be developed before the end of the initial phase. In the meantime, storage companies have to take decisions where, when and which parts of their terminal will be converted into hydrogen, green methanol, ammonia or LOHC receiving terminals. In parallel, shipping companies have to decide when to convert LNG carriers into ships capable for transporting those green products, or to decide to build new hydrogen-dedicated ships (or for that matter dedicated green ammonia and methanol carriers). And finally, exporting countries have to decide which market to serve and what type of green hydrogen carrier to produce. For instance, in the initial phase, hydrogen producers might find the SAF fuels market or methanol bunkering market in their vicinity more attractive than exports of green ammonia to markets far away. Others might not want to be locked-in from day one but prefer optionality. However, some countries might give preference to support a dedicated, vertical integrated value chain between their country and the consumer country in question. These are difficult questions requiring extensive market studies and extensive discussions with potential buyers.

In Europe, there is a direction towards green ammonia as the preferred clean hydrogen-based carrier. Liquefying pure hydrogen in large quantities is still in its infancy. It also requires big quantities of energy to do so and is currently not economically feasible. Nevertheless, further research might find solutions to overcome these obstacles in due course. In addition to converting clean hydrogen into green ammonia, there is an alternative to convert hydrogen into green methanol. For instance, Maersk, one of the world's leading container ship companies, has opted for this green bunkering fuel to replace the fossil bunker fuels it currently consumes as a means to reduce its scope 1 and 2 GHG emissions. Producer countries close to big bunkering hubs might find such market attractive for further development. A third possibility is not to convert the hydrogen in a green hydrogen carrier ready for export, but to use the hydrogen as feedstock in new industries build directly adjacent to the electrolyzer. This could be fertilizer plants, who generally serve global markets, or SAF and renewable diesel plants based on HVO technology. Finally, and the most promising one is the conversion of pure hydrogen into green ammonia. This commodity — presently made from natural gas — is already widely used and transported over long distances. Existing terminal operators are generally familiar with handling ammonia, and so are the big oil and gas, petrochemical and fertilizer companies. However, preliminary studies show that boil-off gas losses of potential hydrogen carriers during storage on cryogenic shipping tanks are lowest for methylcyclohexane (MCH), followed by methanol, ammonia and – at much higher percentage – liquefied hydrogen. Estimated levelized hydrogen shipping costs – liquefaction and storage, shipping and reconversion – in \$/kgH2 are the lowest for methanol, followed by MCH, ammonia and – again at much higher costs – liquid H2.

Once the dominant type of hydrogen carrier for export has been selected and standards have been formulated and defined, the next question will be a decision to re-convert the hydrogen carrier back into pure hydrogen (in gaseous state) or not to do so and to keep it in its original (liquid) form. Technically it is possible to crack it back into pure hydrogen and companies are investigating the construction of such cracking installation in a couple of ports in the Netherlands, but the jury is still out if this makes commercially sense.

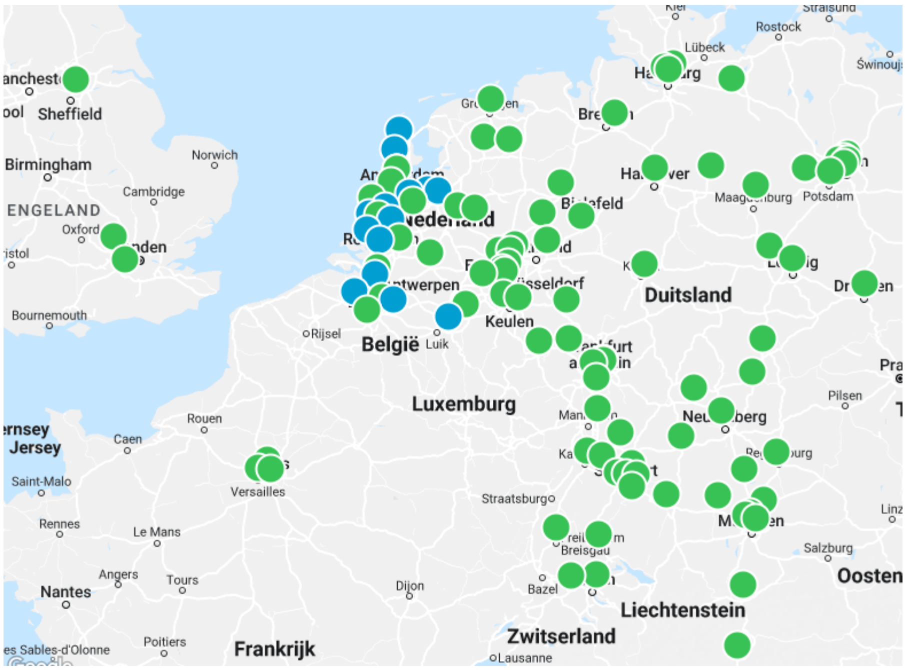
From a commercial and price discovery point of view, the ultimate choice how to use the hydrogen and into which carrier to convert makes a huge difference. If the imported product is not converted back into hydrogen, it will not or at best only remotely interact with locally produced hydrogen. In the initial phase both markets will then develop independently from a price discovery point of view. Moreover, if it stays in a liquid state, under the current regulatory regime, it will not be regulated like natural gas (which is expected to be extended to gaseous hydrogen when shipped through the pipeline networks of the TSOs). In those situations, green methanol or ammonia will most likely compete with fossil-based methanol or ammonia and those markets might be involved in its price discovery process or even be the market plus a delta for CO2 costs and a market premium. In such a case, the ammonia price 'follows' the natural gas price, which is the feedstock to produce grey ammonia. In chapter 4 more information will be presented on those price dynamics. When preference is given to long-term sales and purchase contracts, the ultimate price formula will be most likely set between the green ammonia or methanol producer and the end-customer. Only if a commodity house will take up an aggregator's role in those novel products (like they do in LNG), such buyer might opt to enter into a long-term sales and purchase contract with an commodity trader, who will then on-sell it to one or more end users. Prices will be most likely in $ per ton.

However, if the hydrogen will be reconverted back into pure hydrogen, it is very likely that it will be co-mingled with domestically produced green hydrogen and has to be transported from the import terminal to a final customer via a TSO-owned and operated pipeline network. In such case, the transportation tariff will be set annually by the TSO operator and regulated by national law and EU law and decrees. Based on the expectation that the domestically produced green hydrogen is dominant, it is logical to assume that the imported hydrogen will be priced against the ruling price marker in that region. Because the marginal cost is defined by the marginal cost of the electricity, it is highly likely that in such case the ultimate price will be determined on a new to be established hydrogen exchange (see further below in chapter 4) and that the over-arching driver for setting the price for green hydrogen will be the electricity price, daily and hourly set by the then prevailing merit order. To be sure, today that is the natural gas price most of the time. Price volatility during the day will be thus much higher than is the case for green ammonia or methanol, because prices will be very dependent on the number of hours of sun and wind during the day in a given period of time during the year (and thus very much dependent on accurate weather forecasts). During days with lots of solar and wind, electricity prices already turn negative and drive natural gas out of the merit order. With the rapid expansion of the installed base of renewable energy in the coming years, the number of hours of negative prices will grow, ultimately leading to longer periods where prices are not any longer determined by natural gas, but by renewables. As the marginal cost of renewables is zero, i.e. ‘wind blows for free’, this will have a material deflationary effect on the total energy system over time, resulting in more productive hours an electrolyzer can run economically. This said, wind developers currently demand higher and more guaranteed revenues and want to transfer more risks to overcome the legacy issues where they have been confronted with. Because the running costs of electrolyzers ‘at the other end of the world’ will be very different than at home, it is to be seen how the arbitrage game will play out between domestically produced hydrogen and hydrogen being imported. Green hydrogen producers and buyers thus have to decide basically on an hourly basis (in practice on a one-day ahead basis) whether to turn the electrolyzer on, or not to do so but to buy from an importer, or even to switch back to grey hydrogen for its production when renewable electricity is outpriced by natural gas. Of course, this dynamic game is also highly influenced by the availability of commercial storage of hydrogen for third parties and the captive storage facilities producers and end-consumers might build for trading purposes, and the flexibility the TSOs will provide. The tax levies on each part of the value chain and its structure and the application thereof for the different products and services, plus the price of CO2 is further complicating the price discovery process and its transparency. Grands and subsidies and the terms thereof will also impact the price discovery process and the ultimate price of green hydrogen. Trading in certificates of origin (to proof it is green) might also play a role, as well as other tradable credits. The level of flexibility the European Commission will give to its member states how to implement the policies, rules, systems and decrees will also determine in how far there will be arbitrage opportunities for renewables between the different countries. Price analysis of the Shell 10 MW Rheinland electrolyzer (see earlier) conducted in 2020/21 showed that levies on electricity has a high impact and subsequently on the hydrogen price. At that time, electrolysis was not yet able to compete with reforming of natural gas on production cost of hydrogen. Also in their case, high load factors rather than flexible operation of the electrolyzer lead to the lowest hydrogen cost (i.e. CAPEX costs were dominant over OPEX running costs).

1.2 H2 in mobility

Besides the initial focus on replacing grey hydrogen used as a feedstock in industrial processes by clean hydrogen, several industry players, including the oil majors are working to further develop a hydrogen network for transport, specifically for buses and trucks. The transport sector, particularly heavy-duty vehicles (HDV), can contribute significantly to a European carbon-neutral economy. The growing preference for zero-emission vehicles (ZEV) has been evident in the light-duty vehicle (LDV) sector, with electric vehicles accounting for 11% of new sales in Europe in 2020 [7]. Meanwhile, the HDV market in Europe remains dominated by fossil fuel-powered internal combustion engines, with ZEVs accounting for just 2% of sales in the same year. Several ZE-HDV technologies exist with the potential to deliver real-world reductions in lifecycle greenhouse gas (GHG) emissions of trucks. These include battery-electric trucks (BETs) and fuel cell electric trucks (FCETs), the latter running on compressed hydrogen gas. While several truck manufacturers have already announced and deployed BET and FCET models, high market demand has not materialized as there is a high level of uncertainty regarding the economic viability of these alternative technologies. Hence the expectation that the uptake of hydrogen in the mobility sector will only come over time, and start to make an impact from 2030 onwards. Nevertheless, the first filling stations have been opened, as is presented in exhibit 7 below [8].

Exhibit 7: Hydrogen filing points in Germany, The Netherlands and Belgium [8]



existing filling points

filling points under construction or considered

More than 1,070 hydrogen refueling stations are now operational globally. Most of these stations are located in Asia (c. 650), followed by Europe (c. 280) and the U.S. (c. 120, of which 57 public). In the Netherlands, there are currently 37 locations where people can fill up their passenger cars, trucks and busses with hydrogen. Germany has currently 100 public filling points for hydrogen. The U.S. just has 57 public hydrogen refueling stations, compared with 54,000 BEV charging stations and 145,000 ICE fueling stations. In that respect, hydrogen in mobility is some 20 years behind electric vehicles where the first hybrid car (Toyota Prius) came on sale in Japan in 1997 and the first Tesla prototype was unveiled in 2006. The ambition is to have one hydrogen gas station in every middle-sized and larger

European city by 2030. By then, clean hydrogen should be competitive with gasoil and gasoline. This is currently not the case, to the contrary. Current hydrogen prices are fluctuating between Euro 18/kg and Euro 30/kg, following the local natural gas prices. In June 2023, the price at filling point was Euro 21.60/kg in the Netherlands. For a BMW's iX5 hydrogen, a full tank of hydrogen would then cost in the Netherlands between Euro 110 and Euro 180. With a full tank (taking 6 kg of hydrogen), and an efficiency of 1.19 kg per 100 km according the company, this SUV could drive c. 600 km [8]. Filling up the car with 5.42 kg, the price in the Netherlands was Euro 117.07 in June 2023. This compares with the current delivery price in the U.S. of $ 10-12/kg, higher than c. $ 4-6/kg required for large scale adoption in mobility in the U.S. The current retail price in California is $ 14+/kg.

Until recently, the consensus was that passenger cars, LDVs and short-haul transport would go for electrification, while long-haul and heavy-duty transportation would opt for hydrogen as the preferred clean fuel (together with renewable diesel). Once a truck had to drive more than c. 300 kilometer (km), there was no way you could electrify because such batteries for trucks didn't exist. The tipping point (at 300 km) is at 50% of the total road freight kilometers driven in Europe per year, i.e. 50% of the daily journeys per truck is less and 50% is more than 300 km. 60% of the trucks in Europe drive less than 500km per day. However, recent R&D has resulted in much stronger batteries than anticipated. The energy density of batteries has doubled in the last 7 years, and is actually accelerating since 2020, now standing at 711 $W.h.kg^{-1}$. Since batteries are intrinsically more efficient than the electrolyzer + compressor + hydrogen storage + fuel cell chain, the question is 'will this growth in storage capacity be limited?'. Tesla Semi trucks, which are now coming on the market, can drive c. 500 miles / 800 kilometer. Tesla says its truck consumes 1.25 kWh/mi + grid/charging losses, resulting in low cost of ownership where charging electricity is 2.5 times cheaper than diesel, resulting in savings of c. $ 200,000 / 3 years (source www.tesla.com). This is far cheaper than FCETs, where latest forecasts expect costs are at par with diesel by 2035 (source www.h2accelerate.eu). In the meantime, many western countries are rapidly expanding their battery manufacturing capacity, and China even much more. The latter will have 5.5 TWh of capacity operational by 2031 (versus the U.S. 1 TWh and Germany 0.4 TWh) (source: FT). Hence, it seems that the battle between battery-electric trucks (BETs) and fuel cell electric trucks (FCETs) running on compressed hydrogen gas has just begun.

Taking all vehicles together, worldwide sales of BEVs in 2022 was more than 8 million vehicles (c. 10% market share of the 80 million cars sold). Worldwide sales of FCEVs in 2022 was less than 20,000 units. The BEV/FCEV ratio was thus c. 400 : 1 last year [9]. Global electric cars (BEV – battery electric vehicles – and PHEV – plug-in hybrids) have now a penetration rate of c. 20% globally, with a sales rate of 23% in Europe in 2023, 39% in China, 15% in South Korea and close to 10% in the U.S. Comparison was also made of the charging costs for a Tesla Model 3 and a Toyota Mira in Germany: For a Tesla, charging at home, using excess electricity from rooftop PV system (Euro 10ct/kWh): consumption: 0.17-0.18 kWh/km (Euro 0.018/km). Cost at supercharger at highway: 0.18 kWh/km * Euro 0.42/kWh = Euro 0.076/km (equivalent to 4.5 liters gasoline per 100 km). This compares to 0.011 kg/km at Euro 13.85/kg fuels costs = Euro 0.15/km, or about 2x more expensive than power cost via a super charger and 8x more expensive than charging at home. In Germany, the current total cost of use for long-haul trucks is $ 1.45/km for trucks that run on diesel, $ 1.85/km for a BEV truck and $ 2.30/km for a FCEV truck, resulting in a 4-year parity gap (source: Ballard Power Systems).

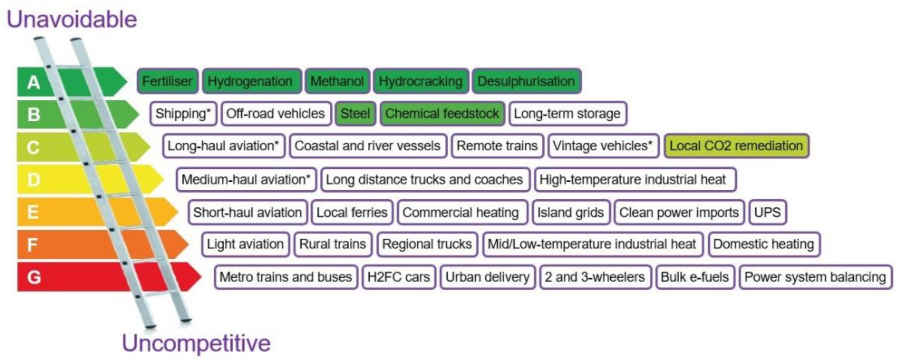
The less optimistic picture for clean hydrogen fuels in transport has been recently confirmed by BP and MAN, Europe's 2nd largest truck manufacturer. In their updated Energy Outlook, 2023 edition, BP's analyses show that clean hydrogen will play a minimal role in the decarbonization of cars. In light vehicles, clean hydrogen has no role to play, even not under their net-zero scenario. 70% of these vehicles will use electricity directly. In this scenario, more than 20% of the energy share in 2050 for light vehicles will still be from oil products, with small amounts of biofuel and natural gas also being used [10]. In heavy road transport BP sees c. 30% of the energy share been taken by clean hydrogen and hydrogen-derived fuels by 2050 compared with 50% provided by direct electricity solutions. However, this will only start to pick up post 2030. Before that time, low-carbon hydrogen demand in heavy road transport is still expected to be very small. The choice between electricity and hydrogen in heavy duty transport is finely balanced and depends on many factors that have to pan out in the coming decades. In both cases, achieving strong adoption requires material vehicle cost reductions, as well as the development of charging and refueling networks. Right now, electricity achieves somewhat stronger take-up across the main trucking categories. But nevertheless clean hydrogen will also achieve substantial penetration, particularly in long-distance heavy duty use cases. MAN is of the opinion that clean hydrogen is far too expensive and therefore will not become a major road freight fuel. According to them, E-mobility is coming now. To their estimation, 80% or even 90% of logistical trucks will be electrically driven. Hydrogen-fueled trucks will only play a small role in Europe's zero-emissions transport future.

Also in the U.S. large scale adoption in mobility is still many years away. First cost have to fall materially and infrastructure needs to be built out. Adoption in the mobility sector might reach an inflection point by the end of the decade. Also in the U.S. counts that even if fuel cell vehicles are more efficient that ICE vehicles, high fuel cost makes cost of ownership unattractive especially compared to BEVs. For the truly long-haul applications (coast to coast) and heavy duty cargos hydrogen could win it from battery electric when supported by strong policy. Hydrogen has an advantage over battery electric vehicles as refueling a truck may take c. 20 minutes, whereas charging it would take several hours, resulting in downtime. Pending regulation this could limit the time a driver may be on the road before taking a mandated break, resulting in higher total labor costs (and more trucks on the road for the same volume that needs to be transported). Also hydrogen doesn't lose efficiency in cold weather as electric vehicles do. For instance a ride from Los Angeles, which is the busiest U.S. port, to Newark, a diesel truck will need 1 stop, a FCEV 3, and a BEV 8, taking 0.4 hours, 1.4 hours and 43.8 hours fueling time, respectively.

This brings us to the conclusion that there is clearly a ranking order where clean / green hydrogen will find its inroads first. The first priority will be the production of (i) green ammonia for the fertilizer industry, (ii) clean hydrogen as a feedstock for the refiners and petro-chemicals, and (iii) to produce heat for those sectors as well as for the steel, cement, aluminum and paper industries. The second priority will be seaborne shipping and aviation. The third priority will be land transportation. This will then be followed by power and heating. The clean hydrogen ladders for the different segments are well summarized in the following exhibits below [11]. However, this not necessarily means that each priority will only starts once the other of higher priority has already matured. But this being said, those with higher priority will get higher priority in strategic attention, new business development, and funding. This will result that those with highest priority will come first, and as earlier described that will be very much around substantial reduction in scope 1 and 2 in GHG emissions in industries, the 'must do' projects. And to be sure, the first 1-3 priorities already requires millions of tonnes of clean hydrogen. To put it more bluntly, without converting those energy-intensive industries away from fossil fuels and feedstocks to clean hydrogen, the Paris Agreement targets will remain out of reach.

The top priority is in the field of chemical feedstocks, heat and industrial processes, where it is all about replacing the use of grey hydrogen in refinery, petrochemical, fertilizer and steel manufacturing processes to lower scope 1 and 2 GHG emissions (Exhibit 8) [11].

Exhibit 8: Priority 1: Clean hydrogen ladder for chemicals and processes

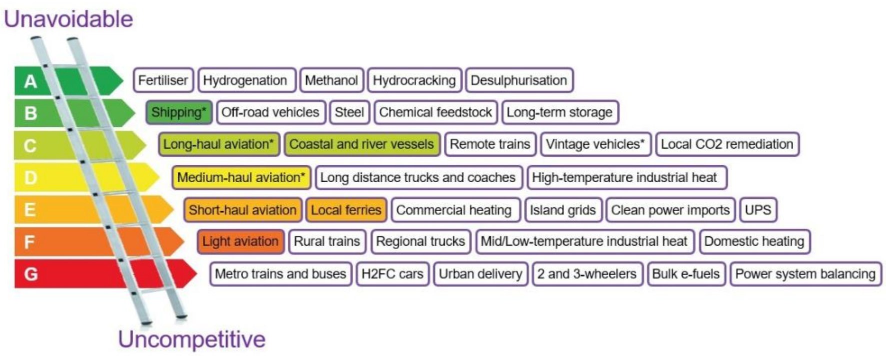


** Via ammonia or e-fuel rather than H2 gas or liquid*

Source: Liebreich Associates (concept credit: Adrian Hiel/Energy Cities)

The next priority will be in hard-to-abate aviation and shipping sectors (Exhibit 9). In shipping, the opportunities for clean hydrogen come through clean ammonia and clean methanol based on clean hydrogen. In aviation, clean hydrogen is the fuel needed to produce SAF in HVO plants. In short-haul and light aviation, battery electric aircraft look like they are going to win as battery energy densities increase and costs come down.

Exhibit 9: Priority 2: Clean hydrogen ladder for shipping and aviation

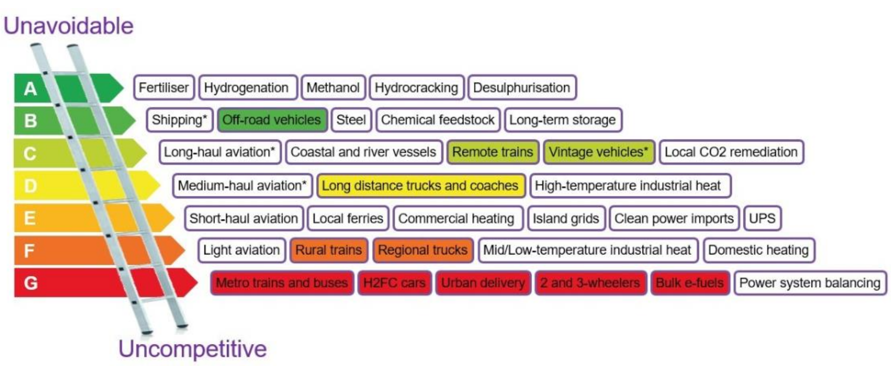


* *Via ammonia or e-fuel rather than H2 gas or liquid*

Source: Liebreich Associates (concept credit: Adrian Hiel/Energy Cities)

The third priority might be land transportation, which might scale up post 2030 but is most likely to stay a niche market for the foreseeable future (Exhibit 10).

Exhibit 10: Priority 3: Clean hydrogen ladder for land transportation



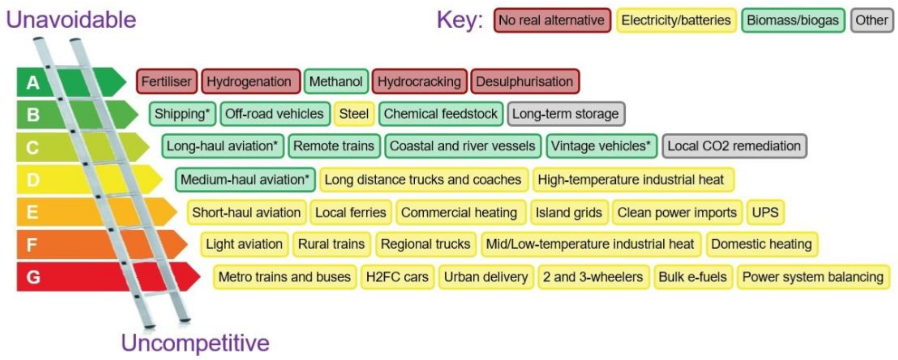
* *Via ammonia or e-fuel rather than H2 gas or liquid*

Source: Liebreich Associates (concept credit: Adrian Hiel/Energy Cities)

Once the large RES production base has been installed, there will be many days a year that there is will be excess electricity for which there is not a direct market and can be used to produce hydrogen that will be stored. It is not foreseen that this hydrogen will be heavily used to produce electricity again because the cycle losses – something that might also be applicable for clean ammonia or methanol, where it does not make economic sense to convert it back to clean hydrogen once imported – are simply too big. The standout use for clean hydrogen here is for long-term storage.

In summary, the next exhibit presents a schematic overview how clean technologies compete and which makes most sense where (Exhibit 11).

Exhibit 11: The clean hydrogen ladder: competing technologies



** Via ammonia or e-fuel rather than H2 gas or liquid*

Source: Liebreich Associates (concept credits: Adrian Hiel/Energy Cities & Paul Martin)

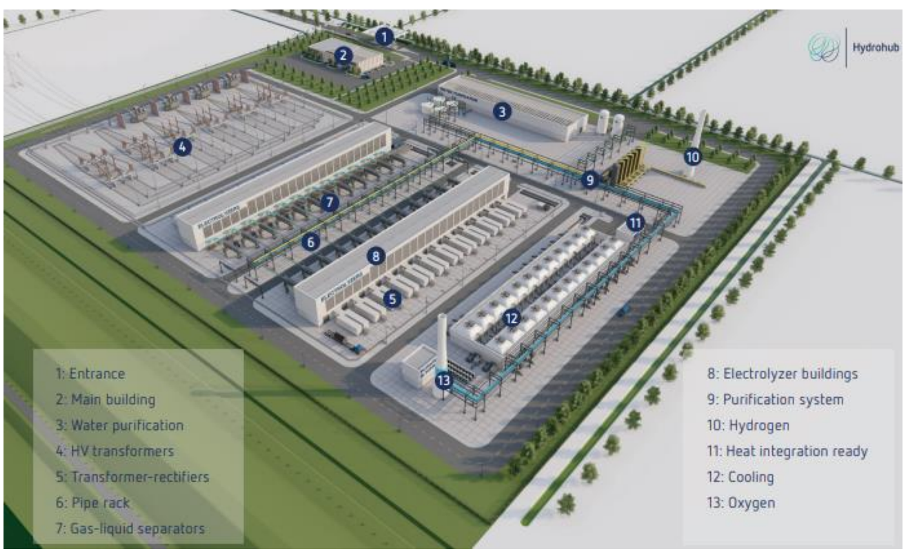
2. Chapter 2

2.1 A One-GigaWatt Green Hydrogen Plant

Given the high green hydrogen ambitions for 2030 and beyond and the fact that we are now upscaling from 20 MW to 200-250 MW electrolyzers, it is useful to summarize the result of a 2-year study on a One-GigaWatt green hydrogen plant [12]. In order to realize the 2030 ambitions, it is key to consider to rapidly upscale the next hydrogen project to such level, even based on a modular approach where the 1-GW project would be subdivided into smaller parts of 2 (480 MW), 3 (320 MW, or 4 (240 MW) subsystems at the plant level, for a total of 6x160 MW AWE modules or 24x40 MW PEM modules. The study, conducted between 2020 and 2022 and built on earlier studies since 2019, flags that there is a great urgency around the need to scale up green hydrogen as a renewable feedstock and energy carrier to meet the Dutch and European 2030 goals. An artist impression of an advanced 1-GW AWE and PEM green hydrogen plant is presented in exhibits 12 and 13 [12]. An alkaline electrolyzer plant is best suited for centralized large scale production for industrial clusters. A PEM electrolyzer is best suited for de-centralized production for road transport and power generation energy storage. Both technologies are applicable in all end-markets but could be less competitive than an alternative technology. Solid oxide electrolyzers are expected to suit best for primary chemicals (ammonia, methanol) and other high-temperature industrial processes, but are ill suited for application in several end-markets.

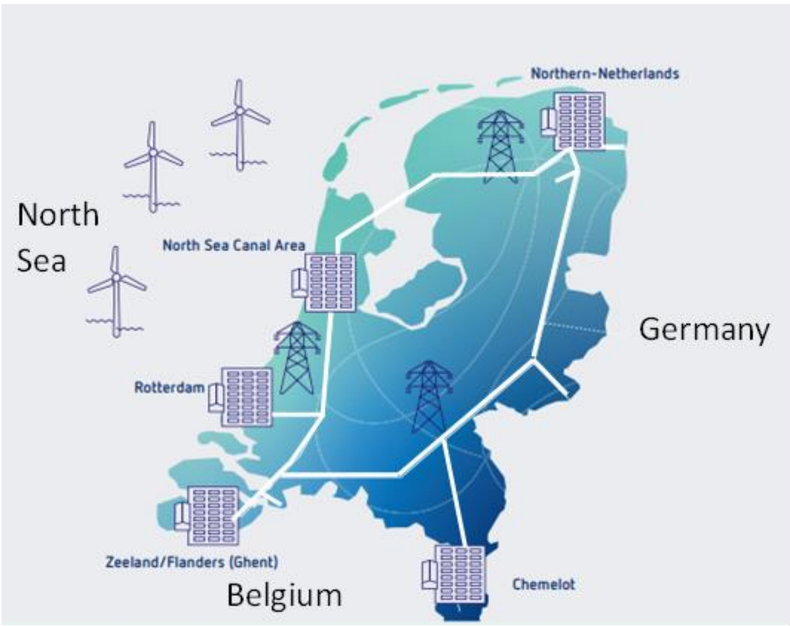
Exhibit 12: An artist impression of an advanced AWE 1-GW green hydrogen plant [12]

Exhibit 13: An artist impression of an advanced PEM 1-GW green hydrogen plant [12]



The Hydrohub GigaWatt-Scale Electrolyzer Project produced an advanced design for a 1-GW green hydrogen plant, which would use alkaline water electrolysis (AWE) and polymer electrolyte membrane (PEM) water electrolysis, and which could start in 2030. The study, conducted in 2020/21, presents the technical design and the associated total cost of a greenfield 1-GW plant that would be built, and up and running in a Dutch port area by 2030. The project shows that anticipated total investment cost levels of 730 Euro/kW or 1,580 Euro/(kg/d) for AWE and 830 Euro/kW or 1,770 Euro/(kg/d) for PEM are within reach. The scope of the technical design comprises all equipment and services required to connect to a 380-kV transport grid that will supply wind power from the North Sea and a pure hydrogen delivery point (30 Bara). The cable is not included in the scope of work, but will be laid by Tennet, the Dutch state-owned TSO. The plant includes electrical installations for transformation and rectification, electrolysis (stacks), purification and compression. It will operate according to typical wind patterns and the electrolyzer will be connected to the Dutch hydrogen backbone — the main transport network for hydrogen currently under construction (Exhibit 14) —, to which it will deliver high-purity hydrogen to be used by customers in the process industry. Furthermore, the design complies with the grid code and HSE and ESG requirements.

Exhibit 14: The Dutch clean hydrogen backbone



The AWE electrolyzer stack is a large 20 MW stack with 335 cells. It operates at a temperature of 100^{o} C. The PEM electrolyzer stack is a 10 MW stack with 310 cells. The stacks are electrically connected to rectifiers, and arranged in moules of 160 MW for AWE and 40 MW for PEM, with improved gas-liquid separators. Exhibits 15 and 16 present a schematic view of both designs. The study concludes that substantial cost reductions can be achieved by incorporating the anticipated technology improvements. These cost reductions are included in the cost estimates. However, the time is short to have the plant operational by 2030. They state that the required technology must be commercially available in 2026 in order for a financial investment decision (FID) to be made in 2028 and for commercial operations to begin in 2030. Reality, however, shows that this timeframe is extremely tight. There is only a 3-year window of opportunity left for accelerated innovation that is necessary to deliver the advanced design on time in 2030. In the Netherlands, the environmental assessment and permitting process for such project will require at least 15-24 months. This will be equally applicable for the offshore wind park and the power cable. Currently big tumbling blocks are amongst others the possible impact of the construction and operations of the value chain building blocks on the European ecological network of protected areas (Natura-2000 areas) and NOx emissions. Equally, extensive safety studies are required, which could take longer given the immaturity of the industry and technologies. Only once the sponsors and development companies have successfully completed the studies and analyses and the authorities (at the national, provincial, and municipality level) have approved the project, they can take FID and enter the Front-End Engineering and Design (FEED) phase. When this is successfully completed, the full value chain is (on paper) in place, including all contractual arrangements, such as electricity supply contracts and hydrogen sales and purchase agreements, risk matrix assessments show which risks were treated and mitigated, transferred, or been taken by the sponsors, and the sponsors have successfully arranged the funding, FID can be taken and the construction phase can start.

Exhibit 15: Scope of a greenfield 1-GW green hydrogen plant based on AWE technology [12]

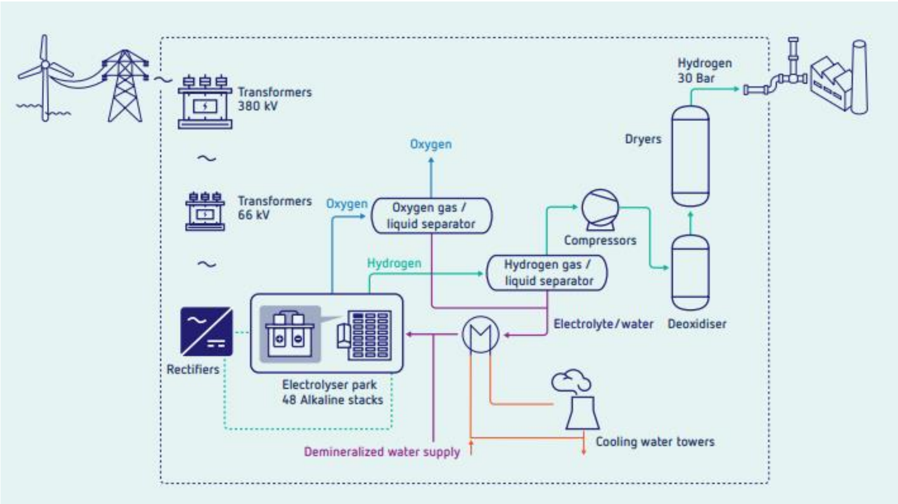
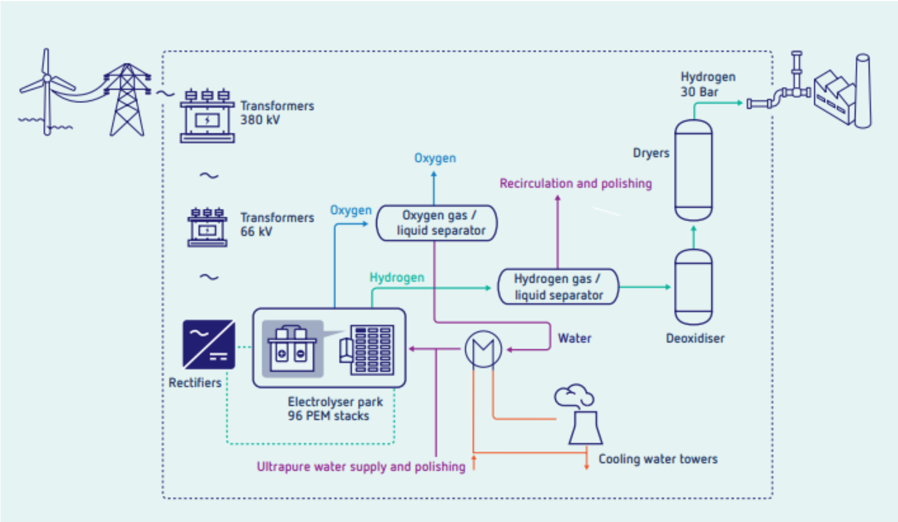


Exhibit 16: Scope of a greenfield 1-GW green hydrogen plant based on PEM technology [12]



The nominal hydrogen output capacity for both designs will be 19 tonnes per hour (210,000 Nm3/hr), or an annual production rate of 72 ktonnes per year (800 M Nm3/annum; 197,260kg/day). This output is significantly higher than what was possible with the electrolyzers available in 2021/22. This is based on available operating hours of the electrolyzer following the wind pattern (4,000 full load hours per annum) and a required availability of 94%. Each advanced AWE 19.6 MW stack results in a hydrogen output of 4,460 Nm3/hour (Exhibit 17). In total 48 stacks are required. For an advanced 10 MW PEM stack, the hydrogen production rate is 2,250 Nm3/hour (Exhibit 18). Overall system efficiency at full load is 77% and 75.8% for PEM and AWE, respectively. The stack efficiency for both novel electrolyzer technologies is 80%. The net electricity supply to the electrolyzers is 963 MW and 948 MW for PEM and AWE, respectively. The cooling demand and the heat supply grow over time from 140 MW to 230 MW for AWE, and from 106 MW to 265 MW for PEM (full load) – excluding 35 MW for another cooling water system for the purification process. The demineralized water unit can produce 230 m3 of demineralized water per hour.

Exhibit 17: Schematic representation of the advanced AWE stack [12]

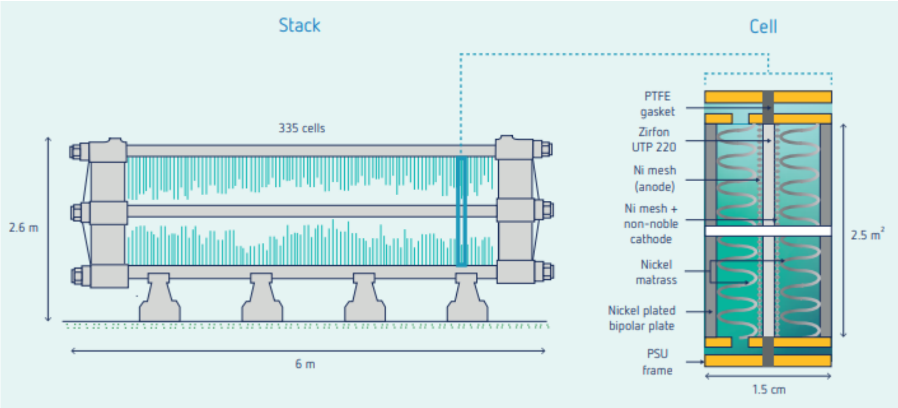
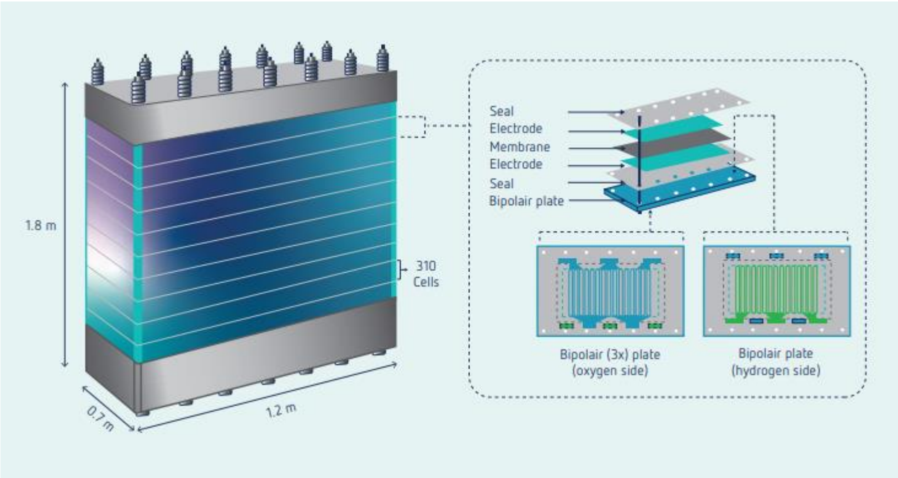


Exhibit 18: Schematic representation of the advanced PEM stack [12]



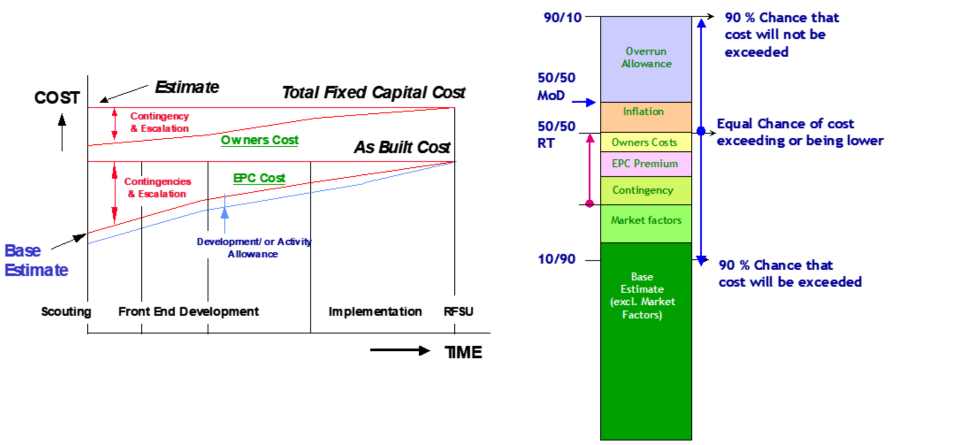
The total installed costs are defined as direct and indirect costs, with allowances and contingency. The estimate of total installed costs is based on October 2021 cost levels. These cost levels have been indexed to 2030 cost levels and have been adjusted for expected cost reductions enabled by increased market incentives and lower unit costs over time. The chosen accuracy of the direct-cost estimates in case of AWE is between a +30%

and – 15% range. For PEM, which is a less mature technology, the range is +40% and -25%. For the same reasons a higher contingency was taken for PEM (which was set at 35%) than for AWE (25%). This should result into a 50/50 Money of the Day (MOD) cost estimate (Exhibit 19) [13]. Given that these studies were conducted before the recent high inflation period, it is assumed that recent cost inflation aspects and the impact thereof were not considered.

The total installed costs of a 1-GW green hydrogen plant were estimated at Euro 730 million / $ 800 million (730 Euro/kW installed capacity) for a plant using AWE technology, and at Euro 830 million / $ 910 million (830 Euro/kW installed capacity) for a plant using PEM technology. When expressed in terms of hydrogen production, the estimated total installation costs would be 1,850 Euro/(kg/day) for AWE technology and 1,770 Euro/(kg/day) for PEM technology. The study explicitly note that the use of the latter numbers is preferred, since they are based on the amount of hydrogen produced instead of the electricity input, thus taking account of efficiency. C. 40% of the costs are indirect costs, owners costs and contingencies and 60% are direct costs (balance of plants, civil, structural and architectural works, utilities and process automation, power supply and electronics and stacks). These direct costs correspond well with consensus electrolyzer costs of $ 380 - $ 450/kW by 2030. Thus also this study already bank on strong cost improvements in the coming years.

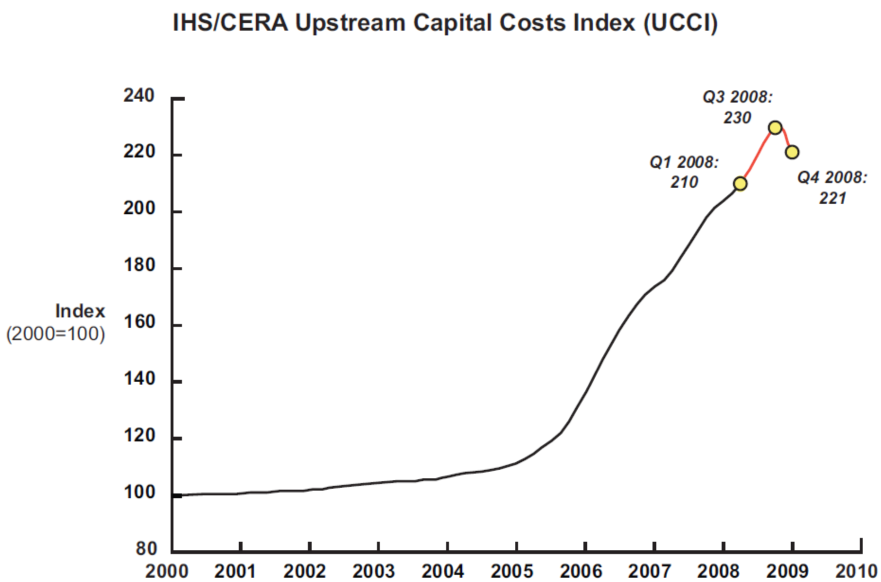
This price estimate of $ 900/kW for a plant using PEM technology is seriously lower than currently estimated by the U.S. DOE, who sees a cost range of $ 975 to $ 1,250/kW for today's electrolyzers (of a much smaller scale), excluding installation costs. Other studies show even higher cost ranges up to $ 1,600/kW for PEM electrolyzers and a very wide range between $ 600 to $ 1400/kW with a average of $ 1,000/kW for an Alkaline Electrolyzer system. This is much cheaper again than the costs of Shell's first 200 MW plant close to $ 1 billion. Consensus is that there will be significant reductions in electrolyzer costs over the coming years to levels of $ 380 - $ 450/kW by 2030 (again only for the electrolyzer kid), i.e. 36-39% of todays cost. First, such plant will be then come onstream by 2032-33 and thus will not help in relation to achieving 2030 goals. Second, we believe that both the consensus cost forecasts as well as the cost calculation done for the 1 GigaWatt plant are not any longer valid and far too optimistic te be achieved in a very short period of time. As explained, the 1 GW plant will be based on expected cost levels in 2028 latest to achieve commercial operating date (COD) by 2030. Even the DOE estimate differs a factor of 4 to 5 from the Shell plant under construction. We would not be surprised if the next plants will have a price tag of around $ 2,000 to $ 3,000/kW (MOD) taking all ancillary Outside Battery Limits costs into account.

Exhibit 19: Deterministic Cost Estimate [13]



It is important to look to the possible impact of a high-cost inflation regime. Looking back to 2021 and 2022, there were three main reasons why inflation surprises rose sharply in those years. First, tradeable goods largely drove inflation surprises in 2021. Second, inflation surprises typically increase following large changes in food and oil prices, so the surge in commodity prices in the first half of 2022 was also a key driver of upside inflation surprises. Third, economic reopening led to inflation dynamics that were both unusually synchronized across countries and not well captured by standard inflation forecasting models. The good news is that the three forces that drove upside inflation surprises in 2021 and 2022 are either reversing or in the rear-view mirror, although progress on the deceleration has continued to fall short of expectations and are in some areas even sticky. But while overall inflation is expected to come down further, a booming renewable industry in the coming decade could result in a situation comparable to 2000s when the oil and gas industry entered an investment phase that was highly inflationary due to a rapid rise in oil and gas CAPEX expenditures in combination with supply shortages, including availability of qualified staff and labor, the rise in complexity and risks of the new projects under development, and a hostile economic environment with spiking oil prices and a rapidly deteriorating exchange rate for the U.S. dollar. While the average inflation rate in the U.S. was 2.83% per year between 2000 and 2008, producing a cumulative price increase of 25.03% over this period, the oil and gas industry saw a cumulative price increase of their upstream capital costs of 130% [14]. At that time, Cambridge Energy Research Associates (CERA), a well-respected energy research and advisory company, compiled the costs of a large group of representative global projects based on the market costs at each moment in time. The data was then converted into an Upstream Capital Cost Index (UCCI). The index was based at 100 in 2000 and was updated at 6 monthly intervals. The index for the period 2000 – 2008 is presented in exhibit 20. During this period the annual worldwide exploration and production (E&P) capital investment more than doubled from $ 200 billion in 2000 to $ 490 billion in 2008 [15]. Today, the CAPEX investments in clean energy are about $ 1.25 trillion (excluding investments in efficiency). According the IEA, these have to $ 3.75 trillion in 2030 in their Net Zero Emissions by 2050 Scenario [16]. The nearly tripling of CAPEX in the 2000s was thus also the consequence of higher unit costs. All new projects were materially more expensive. To meet the climate targets we now have to triple annual CAPEX in the coming 5 years again. This is based on low unit cost inflation assumptions. Would inflation in the industry stay high, we either get less RES for each dollar invested or we have to invest even more. Already today, there is a shortage of 'everything' in the RES market and we see a rise in legacy projects similar to what we saw in the 2000s (and 2010s). It is unlikely to expect that these Industry-wide shortages will disappear soon and costs will come down materially if the ambitions are indeed turned into real investments. Forecasts (May 2023) for e.g. copper is highly leveraged to the anticipated RES growth upcycle, where Goldman Sachs sees a c. 25% rise in the price of copper by 2024 and Citi sees c. 50% upside in its base case by 2025. And to give a feel how recent global inflation impacted U.S. shale development, the marginal supply of crude oil, shale well costs increased from c. $ 5 million per well in 2021 to c. $ 7.5 million per well in 2023, or a rise of +50%. Only now unit costs for average Permian wells could drop c. -10% in 2024 vs. 2023 as activity is declining on the back of lower oil and gas prices.

Exhibit 20



In the first years of the 2000s, the oil and gas industry was adapting itself to the new reality, coming out of more than a decade of low investments during the exploitation phase that ended around 2000 and entering a new investment phase. During the first years (of the new investment phase) most of the work was still on the drawing board, in the pre-FID new business development and engineering phases. Cost inflation was still mild, as been seen in the exhibit. However, from 2005 onwards when all these projects were simultaneously sanctioned by the individual companies, costs started to spike, resulting in material cost overruns and project delays. Today it feels we are basically in the same situation as the oil and gas industry was in 2003. Like then, the industry is asked again to speed up and to start developing more new RES projects, notably in (offshore) wind and hydrogen, and to accelerate the developments into FIDs. Hopefully this time the 2005-2008 period of unexpected rising costs can be avoided. But even if inflation rates will moderate from 15% last year, 10% this year and then 5% per year until 2030, unit costs will be 78% higher versus 2021. And indeed, we now witness the first material declines of material costs and lower services costs in the (oil and gas) industry, having put the leading-edge cost inflation for U.S. E&P companies at 8%-10% for 2023 versus 2022. This is solely driven by much lower demand for oil and gas services, as is witnessed in the ongoing reduction of active drilling rigs and frac spreads of -14% in the U.S. since late last year. Nevertheless, this will only moderate the inflation levels. Suggested levels of inflation are absolutely not high for the industry, given the ambitions and current constraints. Historically, cost inflation only stops when the investment phase comes to an end, or is broken due to a financial crisis (like in 2009) followed by an economic recession. Moreover, the oil and gas industry could afford the huge cost overruns and delays because of higher oil and gas prices and absorb those extra cost because of their balance sheet strength. The RES industry is not in such fortunate situation. Their balance sheets are generally much weaker, and it is unlikely that energy prices will help them to generate higher revenues.

If indeed the 200 MW Shell Pernis will ultimately cost $ 1 billion, including all Outside Battery Limits (OSBL) costs, then a 1-GigaWatt Green Hydrogen plant would cost $ 5 billion or Euro 4.65 billion today. This compares with $ 800-900 million total installed CAPEX costs as presented in the 1-GigaWatt Green Hydrogen Plant report to be built between 2028 and 2030. As mentioned earlier, we would not be surprised if the next plants will have a price tag of around $ 2,000 to 3,000/kW (MOD) taking all ancillary Outside Battery Limits costs and specific industry inflation expectations into account.

3. Chapter 3

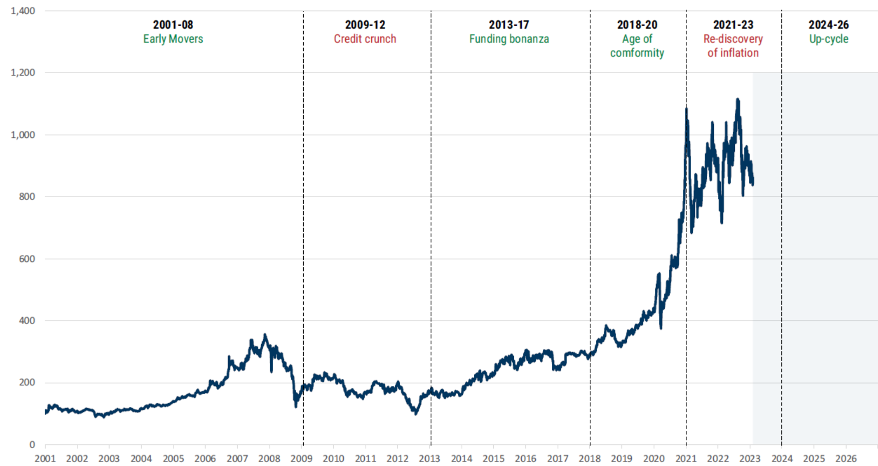
3.1 The evolution of the RES market from 2000 onwards

The rising hydrogen economy will contribute to the rising need of further renewable power installed capacity, beyond power generation demand growth for the ongoing direct electrification of other sectors such as road transport, low-temperature industrial processes and manufacturing, and buildings. Wind power and especially offshore wind power will become an integral part of the green hydrogen value chain in Europe. Without this production source, green hydrogen will not lift off. Given the high load factors and the requirement to have long-term offtake with a minimum of buyers, especially offshore wind is well positioned to become the major supplier of green electrons for electrolysis-produced hydrogen in those countries that do have good wind patterns but less so for solar. This is particularly the case for NW Europe (i.e. the North Sea countries). For this reason, an historic overview and outlook of the offshore wind business will be given in this section and an outlook of what can be expected in the years ahead.

Goldman Sachs recently published the report 'Electrify Europe, Renewables capital cycle; about to enter an "up-cycle".' in which a historic overview of the RES markets since 2000 has been presented [17]. In the report they believe the RES industry is about to exit the 2021-2023 down-cycle, one characterized by equipment cost inflation (2021) and funding cost inflation (2022). For RES corporates with weaker balance sheets, or facing a mismatch between trends in top lines and cost (e.g. offshore wind), this has meant de-rating of their equity price. Ørsted, the world's leading offshore wind developer, was one of them. In their recent policy report 'Let's open the path to progress, shaping Europe's offshore wind industry to a new energy reality', May 25, 2030, Ørsted highlights 'the offshore wind industry is facing a complex interplay of new factors which, while individually manageable, collectively form a maze of risk and complexity, they are now learning to navigate [6]. CAPEX cost inflation, rising interest rates, and supply chain bottlenecks driven by underinvestment from the supply chain have hit the industry hard.' Projects for which power prices were fixed well before the current crisis but companies who forgot to hedge interest rates and raw materials costs have become financially fragile. All is reminiscent to the earlier described investment phase in the oil and gas industry, which was confronted with exactly the same issues and challenges in the 2000s and the first part of the 2010s. However, at that time there was zero sympathy for the industry. To the contrary, they were blamed for the cause of high oil and gas prices. The extra costs and delays were squarely for the companies to manage and their shareholders to absorb. In addition, policy discussions about energy market fundamentals have, according Ørsted, further added regulatory uncertainty to the mix. 'Long permitting times for both generation and transmission projects (as well as for the downstream electrolyzer projects) continue to challenge the industry. Approaches of government, and particularly their treasuries, to cash in on offshore wind as a source of short-term revenue rather than the best option available to rapidly reduce energy prices, and carbon intensity, for consumer and industry, has further catalyzed the challenges. Tender pipelines and offshore lease auctions are being meticulously designed to maximize up-front revenue from projects.' Again, all these things happened in the 2000s as well. Up-front payments to governments – also in the U.S. – run into the billions of dollars in order to win the most attractive oil and gas exploration and production licenses. We think the industry is not there yet and we expect more set-backs before the up-cycle will start. First the mindset about the state of the industry has to be adjusted and formed around the new realities of the RES industry, where a lot can be learned from the oil and gas industry. Second, it is key to stay investable as an industry in order to be able to attract capital for the expansion. This could become highly questionable if no adjustment to new realism is made and governments will not move in their approach.

Only then the RES industry will enter the 6th cycle. This is presented in exhibit 21 (source: Goldman Sachs [17]). In the RES sectors, the early part of the 2000s saw the longest and most positive industry cycle we have seen to date. The industry was in its infancy, with RES capacity additions, developed by a handful of early movers, continued to grow, thanks to supportive policies, especially in Europe. Projects remained relative expensive and required subsidies, but competition was relatively limited. In 2002, the global RES (solar en wind) installed base was a mere 30 GW, or 1% of the installed base. After 7 years of development, by the end of this first phase in 2008, the RES installed base had more than quadrupled to 130 GW, though still representing only 3% of the global installed base. 60% of the global wind and solar capacity was in Europe. Offshore wind was still neglectable. This era was also characterized by a strong acceleration in capacity addition. Between 2002 and 2008 this capacity addition increased from +7 GW per annum to +30 GW per annum.

Exhibit 21: RES proxy share price performance (rebased to 100) since 2001[17]



*2001-2008: Iberdrola; 2008-2011: simple average of EDPR, Iberdrola Renovables and EDF Energies Nouvelles; 2011-present: EDPR

Source: Eikon Datastream, Goldman Sachs Global Investment Research

Projects were expensive. Levelized electricity costs (LCOE) for onshore wind were Euro 90-100/MWh, elevated to prevailing power prices, which averaged c. Euro 40/MWh in the period. Solar LCOEs were c. Euro 400/MWh in 2009. It was absolutely clear that wind and solar required massive subsidies to be economically viable and to build a bigger market share in power production.

Levelized cost of energy (LCOE) measures the average cost per unit of electricity generated by the defined source of production, taking into account all the costs over the lifetime of the generating facility, including initial investment, operations and maintenance, and cost of fuel and capital. LCOE is a simplified way to compare the overall competitiveness of different power generation technologies. The methodology has its limitations. For instance the outcome is highly dependent on input assumptions around load factors and utilization, load factor fluctuations and flexibility, scope of what is and is not included in the investment (e.g. power cables, infrastructure and other Outside Battery Limits cost) and rising maintenance and repair costs.

The next cycle was triggered by the Global Financial Crisis (GFC) of 2009-2012 and caused challenging moments for the RES industry, as it did for the oil and gas industry and global economy in general. The RES industry was confronted by a sudden spike in funding costs, limited availability of credit, and softened political support. Expensive funding and credit tightness, coupled with the need to strengthen balance sheets, required a reduction in RES investments. Nevertheless the global RES capacity continued to grow at a strong pace through this 2nd cycle, resulting in a doubling of wind and solar GW between 2009 and 2012 and reaching a 7% market share. In this period, the rapid cost reduction of solar led to a greater acceleration of this technology. Wind and solar LCOE continued to fall steeply. By end 2012, RES costs nevertheless remained high at c. Euro 75/MWh for onshore wind, Euro 200/MWh for solar, half of its LCOE three years earlier, and Euro 140/MWh for offshore wind according IRENA (Exhibit 22). Subsidies were still required and provided.

The ’whatever it takes’ approach of the ECB to secure the Euro was a watershed moment for the renewables industry the RES industry. It triggered the next investment phase in the RES space, also dubbed as the funding bonanza of 2013-2017. Cheaper funding and falling equipment costs drove the industry and competition ramped up. By 2017, RES market share doubled again to c. 15% of the global installed base. In 15 years the market share of solar and wind had grown from 1% to 15%. Towards the end of the period, offshore wind started to become a core part of the RES industry. Ørsted’s IPO took place in 2016. Onshore wind LCOE costs dropped in 2017 below Euro 50/MWh, the long term historical average power price in Europe. Solar LCOEs dropped below offshore wind LCOEs. They ended this phase at Euro 70-75/MWh and Euro 90-95/MWh, respectively according IRENA (Exhibit 23). This was a key moment for the industry, as it could now do without subsidies and remove an important political barrier.

Exhibit 22: Global weighted average RES LCOEs between 2009 and 2012 (Euro/MWh)[17]

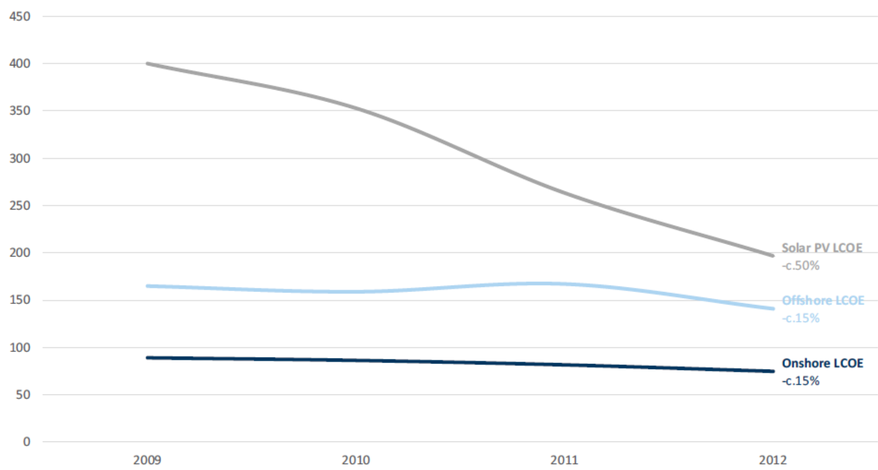
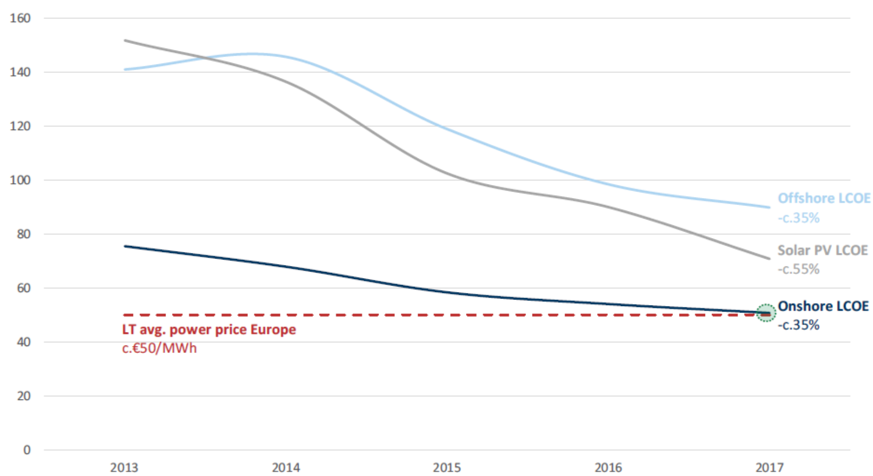


Exhibit 23: Global weighted average RES LCOEs between 2013 and 2017 (Euro/MWh)[17]



Between 2018 and 2020, the RES industry saw a steep reduction in equipment costs, the cheap and easy availability of funding, and the acceleration in net zero policies. This led to a rising number of new entrants such as traditional utilities, smaller developers and the oil majors. As a result, the industry experienced a meaningful surge in competition. Returns came under pressure. Spreads over WACC for typical offshore projects had already come down to 200-300bp. The period was characterized by 'strategic conformity': RES business models increasingly relied on leverage to fund higher wind and solar investments. Equity was (by far) too expensive. Therefore companies had to borrow more to drive weighted cost of capital (WACC) down and to enable rapid growth. Because of increasingly lower (and later negative) interest rates and Quantitative Easing by western Central Banks, capital markets and commercial banks created this one-time opportunity. Companies that would not allow to deteriorate their balance sheets became non-competitive. It was a rat-race to the lowest possible cost for those willing to accept the lowest possible returns and highest possible leverage, based on a most optimistic outlook that such environment will stay there forever. It caused a very supportive environment for taking FIDs, resulting in c. 65% increase of global renewable additions from 142 GW in 2018 to 236 GW in 2020. Global RES installed base grew from c. 1 TW to 1.4 TW, split in 50% solar and 50% onshore wind (offshore wind capacity was still a fraction of the others). The industry also witnessed a true globalization during this cycle. In 2002, Europe accounted for a 82% global market share. By 2011, when Europe saw a peak in annual renewable additions (+31 GW), this had decreased to c. 40% of the global renewable additions (+71 GW). In 2020, Europe's market share had decreased to c. 12% of global RES capacity additions (+28 GW in Europe vs. +236 GW globally in 2020). This mostly reflected the growth in China and the U.S. In this period, cost continued to decline, but at a slower pace than previously. Offshore LCOE prices started to level off at Euro 75/MWh in 2020, while solar and onshore wind LCOE costs further declined at Euro 48/MWh and Euro 32/MWh, respectively.

The current cycle of 2021-2023 was very different and unexpected. It was dominated by rising costs, resulting in a down-cycle and strategic divergence. Spreads over WACC further deteriorated to 150-200bp. Despite supporting policies (the EU Green Deal, REPowerEU, U.S. Inflation Reduction Act) this cycle is tough for RES developers, especially those with weak balance sheets, having aggressively grown by borrowing vast amounts in the global debt markets to fund new projects and having taken open positions of future CAPEX costs. Equipment cost have risen steeply and funding costs have increased materially, while issuing new shares to raise capital has not been advisable given depressed share prices and large dilution effects. Goldman Sachs estimates that between the 2020 trough and

2023, equipment costs for onshore, offshore wind and solar will have increased by c. 10-35%. We believe it is at the top-end of this range and for some parts of the business – such as supply vessels in offshore wind - even higher. This has caused that returns have come under pressure. Notably in the offshore wind space, where unit costs rose the most, returns have come under severe pressure, and even have become negative for certain projects. Like in the oil and gas industry, offshore wind projects take several years of development. Not having expected cost inflation and higher interest rates, and thus not having incorporated the possible consequences of this in their original bids, projects won are not any longer meeting their original investment criteria. This is because of the lag between the time at which the top-line was secured and the time at which costs are firmed up. This lag could be 2-4 years, and the returns on these legacy projects may have to be revised down. In the oil and gas (services) industry this has been common practise for decades, a key driver of the boom-bust commodity cycles. Hence the reason those companies generally have strong balance sheets and are predominantly financed by equity.

The increase in equipment, labor and funding costs suggest a meaningful surge in RES LCOEs. From the 2020 trough, RES costs are still rising. Following a 25-35% increase in equipment costs and a doubling in funding costs since 2021, offshore wind LCOE stands now at Euro 80/MWh and could further rise to Euro 90/MWh in 2024 and stay there for the foreseeable future. This is very different then expected in July 2019, when offshore wind LCOE in Europe were c. Euro 62/MWh and forecasted to further decrease to Euro 51/MWh today, 50/MWh by 2025 and Euro 47/MWh by 2030 [18]. Rising costs, lower headline revenues, and accompanied uncertainty about future inflation levels and the direction how commodity prices will move and how volatile they will be, will impact the corporate strategies. Along the lines flagged by Ørsted, permitting processes are complex, fuzzy, take a long time – 2 to 3 years – and have very uncertain outcomes these days. Many levels of government (central government, provinces, municipalities, government institutions, port authorities) are involved in the review and decision process. Many decisions are politically driven and hence those involved do not necessarily have aligned views or equal interests. Interfaces are not always working properly. Particularly environmental issues could be a constraint, causing delays and make outcomes uncertain, as NGOs and other stakeholders could demand courts to test permit decisions against national and European law. Not that this is wrong, to the contrary, although some court cases are quite controversial. To fight climate change and to improve biodiversity, this is needed. But it will make the whole permitting process complex, time-enduring and the outcome uncertain if environmental risk are perceived to be high. The last two years have seen several energy projects been stranded after a long permitting process. Generally, it will also result in higher costs. In any case long permitting times for both generation and transmission projects (as well as for the downstream electrolyzer projects and any other capital intensive construction project) continue to challenge the industry. Demanding high upfront payments will further negatively impact profitability and lower the possibility of companies willing to take FID in a rising cost environment. Comparable to the oil and gas industry, also there governments always drove the tax claim on oil and gas exploration and production licenses to the extreme, but had to accept to adjust them when the circumstances in the market changed.

Following nearly ten years of strategic conformity, corporates have begun to react differently to the rapid changing environment. Some have decided to preserve capital by cutting investments, particularly in renewables. Others are restructuring their portfolios or are revising their RES strategies and testing them on profitability. A few, however, are in a position to accelerate RES projects, mainly thanks to their strong balance sheet and their continuing commitment to rebalance their portfolio towards low carbon renewables. In a downside scenario, however, some offshore wind developers might be forced to delay or even cancel projects and to take impairments on their legacy projects.

The above evolution is seen in the share price performance of many Green Energy Majors. For instance, the share price of Ørsted increased from Dkr 400.00 in September 2018 to Dkr 660.00 in September 2019. It had a 12-month target price of Dkr 950.00 (i.e. an upside of 43.9%). Already then forecasts showed a nearly tripling of long-term debt by year-end 2021 to fund future growth, while common equity would not increase at all. It was clear that strong grow would thus result in much higher leverage for the foreseeable future. It was a clear example of a long-duration growth stock, something shareholders loved at that time in their search for better returns. In November 2020, its share price had further increased to Dkr 1,080.50, driven by strong expected growth from more auctions. At that time it was already flagged that while the growth opportunity in offshore wind remained sizeable, it was also attracting an enormous level of competition, eating away returns and increasing risk profiles. Moreover, the company would continue to have negative operating cash flows, which had to be funded with extra debt. Nevertheless its share price rose further to a peak of nearly Dkr

1,250 on the back of a strong acceleration of new projects to be auctioned in combination with cheap funding costs. But then the current cycle set in. Long duration stocks were not any longer appealing. Today, the share price is doing about Dkr 614.00 (July 6, 2023), a decline of c. 50% versus peak, reflecting the unexpected impact from cost and funding inflation and a relatively high leverage, which squeezed returns on the project backlog. Ørsted's latest policy paper reflects this sentiment well [6]. With the expectation that the current cycle might come to an end later this year, consensus forecasts show a renewed trajectory of growth, although at a more reasonable pace. But also this time debt levels could double between 2022 and 2025 to support such growth, irrespective of a much more disciplined growth strategy and higher targets set for minimum project returns, demanding spreads of 200-400bp. This anticipated growth only falls short to the policy makers' ambitions to triple the annual RES additions. More new entrants are needed to make this happen.

The reason of mentioning this share performance of Ørsted is to show the significant change that is ongoing in the offshore wind industry, not only at Ørsted, but industry wide. Recent news about a substantial increase in failure rates of wind turbine components at Siemens Gamesa (resulting in a Euro 1 billion of losses) and expected productivity improvements are not materializing to the extent that was previously expected and that they continue to experience ramp up challenges in Offshore wind installations, will further impact the industry. The current situation are reminiscent of the U.S. shale industry between 2010 and 2020 when growth dominated the business. During those years, management and shareholders were generally less bothered about profitability. Each year they could outspent cash flows. Only in recent years, after shareholders made it crystal clear that they were not any longer willing to back non-profitable strategies, the shale oil and gas industry shifted priority to profitability and returns (for shareholders). Now, it seems, that the RES industry is going through the same phases, most likely arriving at the point where shareholders starting to demand better results. For those reasons, most, if not all, companies active in this space will become much more selective in deciding on which project to bid, will demand higher returns for the risks been asked to take, and will pass through the higher cost of capital in future tenders. If those new requirements will indeed materialize, the competitive landscape will improve (also because of less pressure expected from the oil majors, who seem to scale back their renewable ambitions and are retreating from pure offshore wind auctions that do not meet their internal investment criteria and do not bring competitive advantage). Hence, analysts see now better prospects for the RES developers in the coming years. This is further supported by a stronger investor focus on delivering sustainable investment strategies. As earlier said, management has to change their mindset that the pre-COVID world will not come back. This is equally true for governments and policy makers. If not, the chances are that investors will lose confidence and parts of the RES industry become less investable. Top priority ESG themes identified by sustainable investor survey are the highest for 1) Climate Change (84%), 2) Energy Transition (79%), 3) Biodiversity Loss (57%), and 4) Social Factors (55%) [14]. The top-5 key drivers of ESG today are financial materiality, client mandate, regulation, fiduciary duty and investment opportunity, with an accelerated action towards climate adaption, energy transition, system resilience and U.S. IRA (which is seen as a game changer). But the question remains if this will lead to lower LCOEs, heavily needed to make clean hydrogen work.

From a capital market point of view, this positive ‘hope’ is currently not the case for (traditional) utilities, who are generally underweight. While the score good on ‘Macro’, the score bad (lowest quartile) on ‘Earnings’ and ‘Dividends’, ‘Valuation’ and ‘Quality’. European utilities have on average the highest net debt to EBITDA (2023E) ratios (3.2x) of all industry sectors and the highest estimated increase in interest costs as percentage of net income net of cash, close to 15% [19]. The utility sector is thus confronted by the highest estimated sectorial increase in net interest costs vs. leverage. With the ECB communicating a further number of interest hikes in the coming months, this doesn’t make an attractive investment case. Earnings per share are expected to decline this year on average. Dividend growth is low compared with other industrial sectors in Europe. As a consequence, aggressively investing in high CAPEX, low return RES businesses will not help them to satisfy shareholders. Nevertheless equity analysts see a better future for them on the basis that the downturn of the last two years is soon coming to an end.

The downturn in recent years have caused the oil majors, who had entered the green power business in earnest in the 2nd half of the last decade, to revisit their RES strategies. BP already announced their revised RES strategies a month ago, and Shell did the same on their Shell Capital day at NYSE in New York on the 14th of June. Oil companies have never been a great supporter of the power business, which has very different industry and market characteristics and dynamics then the upstream oil and gas exploration and development business and the downstream refinery and marketing business. More specifically, their balance sheet structure and investment metrics were always alien to the RES business. Since 2000, it always have been a difficult decision for them to invest in these 'electrons' utility-type of businesses, other than in trading those electrons. Basically, the step in, step out, and repeated this several times. In general, shareholders were distrustful about them to enter in these businesses, including the RES solar and wind businesses, with many seeing these strategies vague, unprofitable and playing outside their competitive strengths. Moreover, they argued that the companies would never achieve a dominant position in these scattered and highly competitive markets, which are also heavily regulated and contain material long-duration risk. In shifting to power renewables, they argued, the oil companies were accepting to invest in much lower rates of return, smaller resource potential (even the biggest offshore wind project is small in energy terms) and, most importantly, longer paybacks (Exhibit 24) [20]. As a result, their commitment never became convincing, resulting in an flip-flop approach.

Exhibit 24: Economics of Energy Investment [20]

Fortunately, technology and government policy changes over the last three years has now allowed the oil majors to evolve their RES strategies away from developing and owning power assets (ex trading) to hydrogen, CCS, biogas and biofuels (i.e. molecules instead of electrons). Those new opportunities are giving them the possibility to jump to the next arena of competition. Since 2000 the RES business basically consisted out of solar and wind, enabling the replacement of fossil fuels to produce electric power and to electrify what could be electrified (or more precise, to avoid global power demand growth to be met by fossil resources only). It also resulted for the first time in a convergence of the mobility sector with the stationary sector through the arrival and roll out of electric vehicles (EV). Although from the outset it was felt that these changes were creating new and attractive opportunities, in practice, these transitions were seen as a big threat. But the world has now really moved on from seeing the energy transition as a linear solution through green electrons, which was a real struggle for the oil companies. Now there is a growing appreciation of the parallel need for decarbonized molecules that can help industry and sectors like long-distance heavy transport, aviation and shipping reduce their emissions. Through the arrival of clean hydrogen now also the most challenging parts of the de-carbonization cost curve could be tackled. This new emerging business is much more complex than the energy transition has been so far, as described hereabove, and for these reasons will have much more complex business models. Developing such complex business models is at the heart of the oil industry. The advantage of this new emerging market for oil companies is that energy molecules play into strong adjacencies with their existing hydrocarbon businesses. It is therefore not surprising that clean hydrogen, bio-fuels and bio-gas become more prominent in their corporate strategies. It is expected that investments in those segments will materially upgrade the return profile of their low carbon CAPEX, moving away from utility-style returns in renewable electrons, towards more oil-like returns in renewable molecules. In addition, payback of low carbon molecules investment (biofuels, blue hydrogen) are significantly shorter than renewables. Much of these new strategies are now underpinned by new policy initiatives announced by the European Commission and the U.S. government (REPowerEU, Fitfor55 and Inflation Reduction Act, respectively). The focus will therefore be on Europe and the U.S. to build such new businesses. Up to now, policy support for those new green molecules developments is yet not the same outside the U.S. and Europe, however, restricting early-stage investments around potential green hydrogen export hubs (through green ammonia, methanol, LOHC or SAF). Scaling of these new export-oriented businesses is more likely to come in the 2030s, as further described at various places in this report. As a pre-requisite, governments must avoid to over-regulate these new businesses that will create barriers for investment and push them in the direction of where RES is today. Moreover, we are still at the start of this journey and the transition is far from complete. Policies must now be consolidated in such a way that they will produce positive consequences for the industry and energy transition at large.

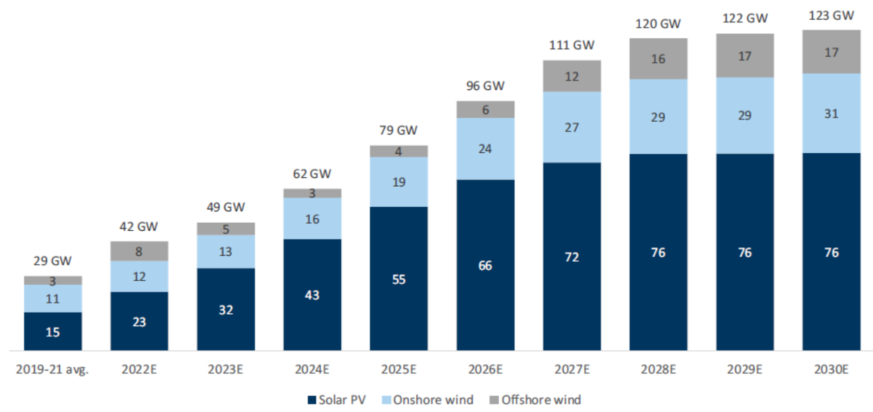
Oil majors are thus currently making a monumental shift towards integrated offshore wind into green hydrogen into green feedstocks and fuels. At least, they have huge plans sitting on the drawing board. By doing so, they will initially focus on replacing grey hydrogen by green hydrogen as a feedstock for their refining and petro-chemical processes, and thus lowering their scope 1 and 2 GHG emissions, later to expand into the mobility sector, helping them to decarbonize and to lower their scope 3 GHG emissions. Such investments must help them to create the superior asset portfolios of the future and to become the future champions in the production and marketing of green molecules (some of the majors will also build the world's largest charging stations network at their fuel stations). Generally, for offshore wind projects that will be auctioned in the coming years, at least for those in the North Sea, this means that their economics will be set by the price of green hydrogen and not any longer by the wholesale electricity price (even if the electricity will not be directly bought by electrolyzer companies under long-term sales and purchase agreements). For this reason the developers, including the oil majors, will start developing new metrics and investment criteria, taking the level of value chain fragmentation and the expected price discovery process into account. In how far the oil companies will develop their own offshore wind parks and strive for vertical integration, or accept pure wind developers to participate in these integrated hydrogen projects, or will just purchase the RES electricity under long-term contracts (or even partly spot) has to be seen. Equally, there will be clean hydrogen buyers who do not want to invest themselves (in any part of the value chain) but just want to buy hydrogen or a hydrogen-derivative under long term contracts. Those have to decide from whom they want to buy the green hydrogen molecules and on what terms. In any case, the CAPEX cost are massive: We estimate that a 1-GigaWatt of offshore wind park will cost c. $ 3 billion. A 1-GigaWatt of electrolyzer will cost c. $ 2-3 billion, and even more based on the estimated costs of Shell's 200 MW electrolyzer project currently under construction. In the Netherlands, the commercial building blocks of a domestic hydrogen value chain will thus require $ 5-6 billion in CAPEX investment for a 1-Gigawatt system. We expect that this is still a conservative estimate. On top come the offshore and onshore power cable and the conversion costs of natural gas pipelines into hydrogen pipelines to be executed by the state-owned energy companies. To achieve the EU 2030 target, we have to build more than 400 of the systems Shell has currently under construction.

In 2015 offshore wind installations in Europe had an installed capacity of c. 12 GW [21]. In the rest of the world this was neglectable. In October 2017 the outlook based on government's intentions showed a 9x expansion of wind offshore installations by 2030 vs. 2017 levels. By 2030, the installed base in Europe would be 91 GW, in the Americas 8 GW and in Asia 26 GW [21]. At that time in 2017 renewable auctions saw already an acceleration in cost reduction for offshore wind. However, it was foreseen that the cost of offshore wind would stay above the forecasted wholesale power price through 2020 – 2028E, implying that offshore wind would continue to need political support and subsidies to be installed if power prices drop. Levelized cost of energy (LCOE) over the lifetime of the project based on prices in offshore auctions based on commissioning year would see a decrease from Euro 156/MWh in 2018 to Euro 68/MWh in 2022. It was forecasted (in 2017) that this could go further down to Euro 34/MWh by 2030. The expected reduction in LCOE was driven by lower unit investment costs, more efficient turbines and lower cost of capital. Going forward, increase in turbine size (12-15MW) would continue to drive down investment costs and increase efficiency. As a result, investment costs for offshore wind were expected to go down from c. Euro 4 million/MW to Euro 2.6 million/MW by 2030. This would translate in a total CAPEX investment of c. Euro 256 billion for the manufacturers and Euro 312 billion for the developers between 2017 and 2030.

Two years later, in 2019, the initial market outlook for the global offshore wind was already outdated. New forecasts showed an accelerated growth to 207 GW in 2030 versus earlier estimates made in 2017 [18]. This extra growth came completely from more instalments in the U.S. and Asia. Some expect even higher growth, up to 250 GW of offshore wind capacity by 2030. This might be the case, but also changing industry dynamics, a restructured merit order by then, less driven by natural gas and more by renewables with very low marginal costs suggest lower returns in this space. In the meantime, competitive pressure will remain irrespective of a more focused approach by the oil majors, where some have presented to become much more selective in allocating capital to RES power production in the coming years. Also growth in this space will become increasingly more reliant on equities because funding growth of this scale (through debt) has become harder with higher interest rates. Also capital recycling will become more difficult, especially for the less lucrative legacy projects that were sanctioned before the rise of inflation, and now under construction against higher unit costs. And finally, some of the RES developers have balance sheets that limit them to grow aggressively.

Latest expected annual RES additions in Europe show a 3x increase by 2028 versus today (Exhibit 25) [22], from c. 40 GW annually of wind and solar additions to c. 120 GW at the end of this decade. In aggregate 762 GW of RES capacity will then be built during this period. European offshore wind accounts for an aggregate increase of 80 GW between 2023 and 2030, or approximately 10% of the total expected additions between 2023 and 2030. In the later years of this decade new offshore wind installed capacity per year would have to double of what has been installed last year. At a cost of Euro 3 billion/GW today to decrease to Euro 2.82/GW in 2026, this equals to Euro 225+ billion CAPEX investments in additional offshore wind in Europe in today's money. With the right policies in place, it is expected that a lot of this will find its way to the new green hydrogen business and its applicants. Offshore wind CAPEX unit cost are not equal in different regions though. Developed European markets (UK, Germany, The Netherlands) saw falling CAPEX as a result of bigger turbines, economy of scale, and industrialization of deployment until recently. Cost inflation and supply chain constraints have turned this trend, with rising unit costs now. New markets (U.S., Japan, Taiwan, South Korea) see higher costs [23]. This lead to a CAPEX range of as low as Euro 2.2 million/MW to as high as Euro 4.5 million/MW for projects auctioned until last year summer. Different than earlier predicted, this cost range is now expected to rise, probably substantial, especially in the mature markets, with several of these legacy projects having become unprofitable.

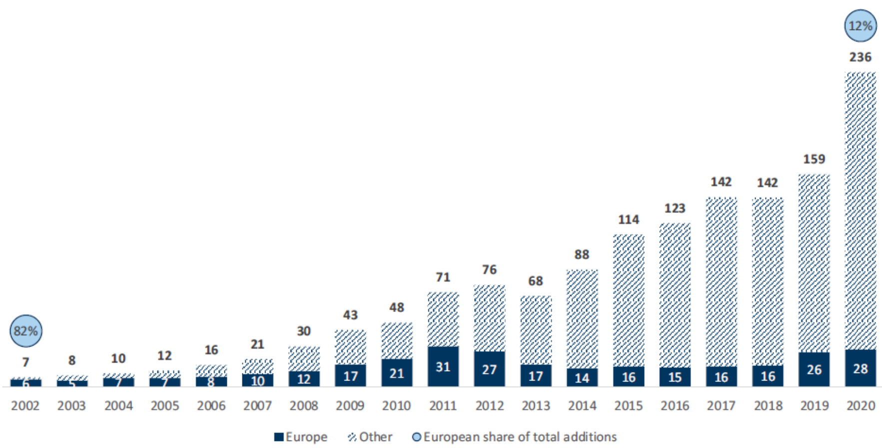
Exhibit 25: Europe RES additions (GW) [22]



Source: Goldman Sachs Global Investment Research

Under the REPowerEU plan, Europe is now planning to reach 75% of its power production from RES (hydro, wind, solar, biomass etc.) by 2030, versus less than 50% currently [22]. By 2030, the EU is targeting to reach a RES installed base of 1,236 GW. This implies: (i) a c.15% upgrade vs the Fit for 55 plan, (ii) a 3x increase in the RES installed base vs 2022, and (iii) c. 90 GW annual additions from 2022 until the end of the decade, on average. Although this is quite ambitious and some 40% higher than earlier forecasts (54 GW annual additions versus now 90 GW per year additions), the direction is clear, even if it takes a bit longer to install +491 GW solar and +271 GW wind. Particularly the wind goals may prove optimistic. Whatever will be built, a big chunk of the offshore wind additions will finds its way into the green hydrogen business. Without the latter not being built, there is no need to build the windfarms and vice versa, if parks will not be built, electrolyzers will miss the power. Nonetheless, the ambitions are unprecedented compared with what Europe has installed since 2000. In hindsight, it is regrettable that Europe actually decreased its annual RES additions for 6 years between 2013 and 2018. Between 2014 and 2018, annual RES additions where basically half of peak year 2011 (Exhibit 26) [17]. The collapse of oil prices in 2014 in combination with the big sums of subsidies that were needed to make RES economically viable in those years might be a dominant driver for this low interest in adding more RES capacity.

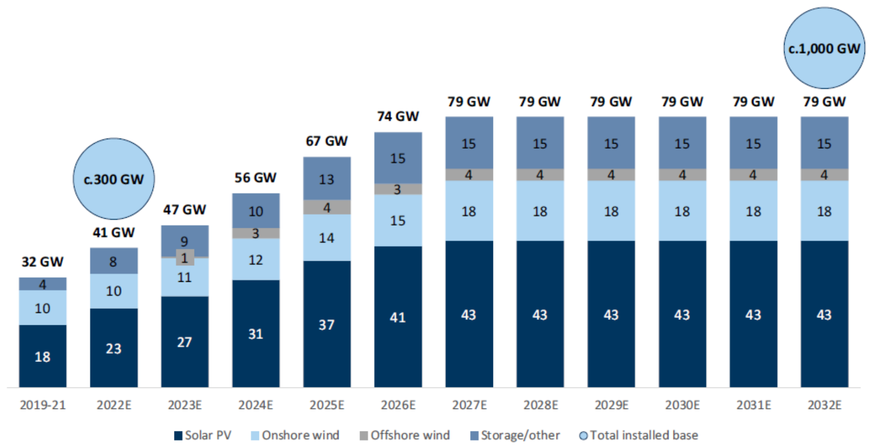
Exhibit 26: Europe's share in Global RES additions per year (GW) [17]



The U.S. Inflation Reduction Act (IRA) is the most ambitious ever clean energy plan introduced in the U.S. Over the coming ten years, the plan could more than triple the RES installed base, from c. 300 GW to c. 1,000 GW [24]. Based on what the industry is expected to be able to ramp up in additions in wind and solar, the annual expansion of RES could grow from c. 30 GW annually to c. 80 GW annually by 2027 (Exhibit 27). Offshore wind accounts for an aggregate increase of 35 GW between 2023 and 2030 (versus zero in 2022).

In total this means annual additions of c. 115 GW in offshore wind in the U.S. and Europe. The rest of the world is expected to see a growth of c. 95 GW in offshore wind until 2030. This is on top of the c. 59 GW that is fully commissioned, but includes the 17.3 GW that is currently under construction and the 9.9 GW for which FID has made, leading to an installed base of c. 269 GW globally by 2030 [25]. Of this capacity, 124 GW has a high project confidence (including 86 GW that has been fully commissioned, is under construction and for which FID has been made), 113 GW a medium one, and 33 GW a low confidence right now. In line with this expected accelerated growth, we already see a material step up in offshore wind capacity auctions this year. Ørsted expects more than 25 GW of offshore wind auctions this year, compared with 6 MW in 2020 and 2021.

Exhibit 27: U.S. Res additions (GW) [24]



Source: Goldman Sachs Global Investment Research

For comparison, European daily power load for nine European countries (Austria, Belgium, France, Germany, Italy, the Netherlands, Spain, Switzerland, and UK) fluctuated between 170 and 290 GW, with an average of c. 230 GW in 2022. Daily renewables (solar, wind, hydro) power generation for these 9 countries is between 40 and 120 GW, with an average of c. 80 GW. The daily solar range is between 5 and 35 GW, with an average of c. 20 GW. The daily onshore wind range for these countries excl. UK (doesn't break out onshore and offshore wind) is between 10 and 70 GW during the year, with an average of c. 30 GW. The daily offshore wind for these countries excl. UK fluctuates between 0 and 10 GW during the year, with an average of c. 5 GW in 2022. The daily hydro power range for the 9 countries is between 15 and 35 GW during the year, with an average of c. 25 GW. The daily nuclear power range for the 9 countries is between 50 and 70 GW during the year, with an average of c. 55 GW. The daily gas-fired power ranges for the 9 countries is between 20 and 80 GW during the year, with an average of c. 50 GW during the year. And finally, the daily coal-fired power range for the 9 countries is between 8 and 40 GW during the year, with an average of c. 22 GW. Offshore wind is thus still a small contributor today and will grow materially if the acceleration of installations is going to take place.

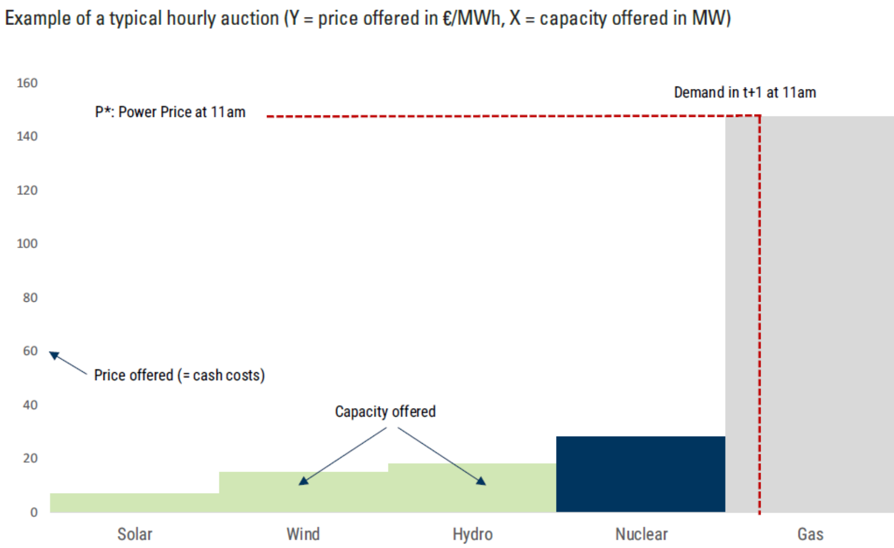
Future plans show that there will be enough RES projects that could underpin the clean hydrogen aspirations as set out by the European Commission. But to support 10 million tonnes of hydrogen production, it will take a fair share of RES power production. For instance, European offshore wind accounts for an aggregate increase of 80 GW between 2023 and 2030, with an effective average output of close to 300 TWh (42% average fixed bottom offshore wind capacity factor x 8760 hours x 80 GW) . Larger turbines will increase the load factor, but wind continues to be an intermittent source of supply. Based on 4,000 hours per year of effective output, a 1 GW offshore wind park will deliver 4 TWh. According the EU Commission, 10 million tonnes of green hydrogen output requires 500-550 TWh of RES electricity input (500 TWh x factor 3.6 = 1,800 PJ x 70% efficiency of the electrolyzer = 1,260 PJ output. There is 120 MJ/kg hydrogen, delivering c. 10 million ton). Thus if all electrolyzers will run on dedicated long-term power purchase agreements, then the targeted expansion of offshore wind in Europe will not be enough to supply those plants with electricity. However, if the electricity comes from a large portfolio of offshore wind, generating in aggregate more power, we need a load factor of c. 76% to satisfy all targeted power demand from electrolyzers in Europe to produce 10 million tonnes of hydrogen. Thus even if you take the rule of thumb that 1 GW (wind + electrolyzers) yields 0.1 million tonnes hydrogen per year, you still need 100 GW of offshore wind. Of course, a part of the electrolyzers will be supplied by solar, notably in Spain and the other south European countries, and onshore wind. The European Commission estimated 500 TWh of renewable electricity that is needed to meet the 2030 ambition in REPowerEU of producing 10 million tonnes of renewable fuels of non-biological origin (RFNBOs), i.e. green hydrogen, corresponds to c. 13% of total EU electricity consumption (of which a large part is still fossil based today). In regions where many electrolyzers will be built, this regional share would be much higher. This will definitely have an impact on electricity prices and on the price discovery process in such regions. One could also conclude that there are very significant cost benefits for producing hydrogen integrated with grid power (i.e. system-serving electrolyzers), compared to stand-alone power-to-hydrogen. Most likely (government-owned / controlled) utilities will indeed build system-serving electrolyzers. In is unclear if the industry, who need hydrogen 24/7, will see this in the same way. By far the cheapest industrial energy can be provided to 'opportunistic' energy users who can switch between hydrogen and power, and between renewables and natural gas.

Power prices have been extremely volatile the last couple of years. For developers, this effectively means more variability that they have to manage and hedge. This higher operational risk enforce the traditional utilities and RES developers to structure (or renegotiate) their sales purchase contracts with cost pass through or indexation clauses to limit their exposure. Price floors will become increasingly important. A large part of the current wind and solar assets in Europe are contracted anyway. But for legacy projects, the term and conditions are flawed and do not fit with current market dynamics. At the same time, the oil majors and big commodity traders might want to take this risk, buying the 'electrons' without having to invest in the wind farms themselves and manage the risk exposure through their large trading books. By connecting and optimizing supply with demand, the will become the natural integrator and wholesale marketer of power.

Consensus forecasts still predict that LCOE would come further down towards 2030, especially for offshore wind due to larger turbines and maturing supply chains. We believe that this is now not longer the case. Based on the then latest secured projects, the LCOE range for offshore wind globally was c. Euro 80-90/MWh last year [23]. This is in line with the earlier mentioned prediction that offshore wind LCOE could further rise to Euro 90/MWh in 2024 and stay there for the foreseeable future [17]. Today, there is far less comfort in cost levels predicted in 2020/21/22 (i.e. before inflation started to rise and now that industry cost inflation is expected to stay) and developers now have to assume possible higher LCOEs in their economic valuations. Those higher input costs have lead to a strategic shift. Most participants, if not all, are now pointing out to favor 'value over volume'. This has not only led to a situation of higher PPA prices, but also appear to result in higher returns over WACC. According the analysts, this could translate in project IRRs of c. 8% compared with 6% until two years ago. However, the negative impact of one or more legacy projects could push this out in time. How structural this will be is topic of debate.

Given the rise of clean energy and of fixed cost generation overall the marginal pricing system could come under pressure. In the European marginal system, power prices are set via hourly auctions where marginal plants (i.e., the most expensive power stations that manage to sell output in that particular hour) set the price for the entire system, for that specific hour. In such system, the paradox is that thermal plants set prices for about 70-75% of the hours despite producing less than 20% of the total annual output. Wind and solar are relatively cheap, fixed-cost power generation sources, where CAPEX accounts for the vast majority of total costs (c. 70-80%), with no fuel costs and low running costs. Thermal plants are much more expensive facilities, featuring high variable costs (fuel and carbon). If the EU ambitions are largely met, by 2030 the vast majority of power could be produced by hydro, wind, solar and nuclear across Europe. The role of gas/LNG (and coal) will be diminished by then, or at least will become much more a price taker than a price setter, which it certainly was last year. Currently, European gas demand in power is 104 bcm (vs c. 317 bcm non-power gas demand in 2023) [26]. Irrespective of price, European gas demand (and thus LNG imports) will further shrink because of the vast expansion of renewables. Hence over time, natural gas will become less the marginal supplier, which currently sets the price for the full merit order. It will be pushed out of the merit order increasingly more, been replaced by the second most expensive marginal producer – the most expensive power producer allowed to generate electricity in any given hour. Over the last couple of years, natural gas demand in power has been remarkable stable, with gas plants generating less than 20% of the electricity needs of Europe. At the same time, they are marginal for c. 75% of the hours. In other words, around ¾th of the time gas is used to produce electricity and set the power price. In an increasingly number of hours it contribute only a couple of percentage of the actual electricity generated in that hour. And the occasions that this would happen will only diminish with the arrival of a bigger renewables base. Thus as long as gas stays within the merit order to balance demand with supply and when gas prices are high, it will keep power prices at high levels as well (Exhibit 28) [27]. But at a certain moment, when more renewables are operational, it is likely that gas will start to be pushed out the merit order for more hours during the day, and ultimately for more days of the week. After all, a larger share of fixed cost technologies (which have low cash variable costs) would result in a flatter curve and in lower wholesale power prices. Putting it differently, remunerating renewables with low variable (fuel) costs based on marginal pricing seems to bear littler economic rationale if that marginal price is set by gas (and carbon). The price of those two has basically nothing to do with the cost base of a wind or solar park. Of course this is based on the assumption that RES supply will grow faster than the overall power demand as a result of the electrification of Europe and the arrival of green hydrogen. It assumes that 'overbuild' of wind and PV will take place and is inevitable in due course. However, will renewables additions stay behind the growth in power demand, then natural gas might even take a larger market share. But such outcome is seen as unlikely. Instead, it is foreseen that natural gas demand will become the swing supplier to catch the variations in RES power at time we have more or less sun and wind, and more or less water for hydro-power and cooling the nuclear plants.

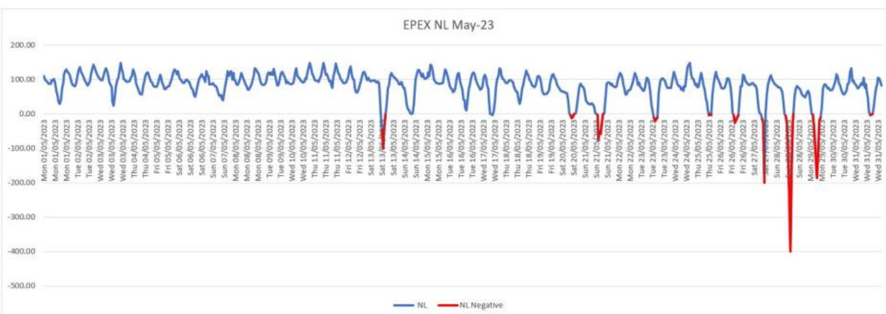
Exhibit 28: Typical auctions for a given hour in a day-ahead market (October 2021) [27]



Over the longer run, the rising share of RES should transform the supply curve. Irrespective of the continuation of the marginal pricing system based on hourly auctions and marginal pricing, the bigger share of clean energy and given its fixed cost generation overall, the RES expansion could drive out gas as the marginal supplier and become the price setter for an increasingly larger period during the day, week, month and year. Already today, we see the first short periods of negative electricity prices in Europe (Exhibit 29). Prices have been as low as Euro minus 400/MWh recently. How this will further evolve is highly dependent on how much residual load will become available. This will become highly dependent on the number of hours of solar and wind at a certain moment in time. But it is growing rapidly. In 2022, the number of hours with negative prices in the Netherlands was 97 hours. So far this year (16 June 2023), the number of hours with negative prices was 125 hours. High RES output, underpinned by a target of c. 70% of overall power production capacity in Europe by 2030, will result in low (but volatile) power prices as low as we now already see at times of ample supply. Actually, Germany already touched 73% of its power supply coming from RES for a day in July 2023. On average in the first half of 2023, renewable generation constituted 57.7 percent of the net electricity generation for public power supply in Germany.

Low RES output because of cloudy and wind-less days, will require backup power. Pending the price of natural gas, the most logical fuel for back-up, prices could spike. This new dynamics will certainly create more price volatility and less price visibility in European power markets. For TSOs, costs to stabilize the grid throughout the day will go up accordingly. Accurate weather forecasting becomes critical. But years of more or less wind, solar and availability of hydro-power, all impossible to predict further out than 1-2 weeks will create an instant market with potentially large changes in demand for natural gas to accommodate RES power markets, estimated as much as 30% of annual average natural gas demand in 2030.

Exhibit 29: Electricity prices on the EPEX exchange for the Netherlands in May 2023 (Euro per MWh)



For these reasons, industry players could work on innovative tailored-made contracted market designs, especially for supplying clean energy to electrolyzers. The rising share of fixed cost power generation sources (wind, solar, nuclear and hydro) in the electricity mix, and the shrinking role of variable cost plants (thermal) is likely to lead to a new market design where pricing is no longer reliant on marginal pricing. A new market design based on PPA contracts may prove a better solution [27]. Such contracts would decouple the price from the most expensive resource that sets the margin price and thus significantly lower prices when natural gas prices are high. This could lead to a major redistribution of profits across the value chain and technologies, and will define the profit zones and risk profiles and distribution of risks. Contracted renewables would probably feature much longer duration contracts (as required by electrolyzer developers and their clean hydrogen clients). They therefore enjoy better visibility on returns, enabling to raise more external financing, and see further valuation multiple expansion on the back of long-term contracts with a small group of high rated companies. Moreover, in the early years of the development of clean hydrogen markets, the price discovery process is likely to be fragmented, and irregular, perhaps even absent for long-term supply contracts, also supporting the case for new contracted market designs. Under such contracts, it will become important who will decide what to do with the electrons that are contracted but not always needed for electrolyses for whatever reasons.

These reasons could occur because the electrolyser operator decides not to run the facility but e.g. to opt for purchasing clean hydrogen (instead of producing it) if prices demand them to do so, or if the company sees possibilities to on-sell the electrons to power buyers in case of attractive market circumstances. In other words, both the supply of green electrons will not only be variable (because of wind and solar variation and the option to produce or to buy), but so will demand because of electrolyzer load factor optimisation driven by price differentials and arbitrage opportunities. Parties involved have thus to work on tailor-made market designs, which fulfil their corporate demands. The more those parties believe the power (and gas) prices stay volatile and unpredictable, the more time needs to be spent on continuously running price simulations to determine instant outcomes on the economic impact for each and all building blocks along the value chain. As noted before, there are very significant cost benefits foreseen for producing hydrogen integrated with grid power production, compared to stand-alone power-to-hydrogen. However, the associated risks might be too large both for the RES producer, not being sure what earnings power it will have, and the electrolyzer developer who is uncertain about the economic value of its CAPEX investment and have to match its contracted supply. Commercial risk reduction will become a critical factor along fragmented but highly inter-connected value chains.

If commodity prices were to spike again, a reform in power markets and the development of new designs may become more urgent. This could lead to a transition to a more regulated and contracted power market system enforced by politicians who want, as already earlier mentioned, low and stable prices with strong predictability and visibility. But even if we see power prices stabilize at current levels, still there is a need to work on new designs that better accommodate the expanded RES installed base and the arrival of a new off-taker in the form of electrolyzers by the end of the decade. At the same time, new designs must support the transition, not to frustrate it. The existing marginal pricing design drove out the expensive diesel oil plants in favor of highly efficient gas-fired power plants and, in conjunction with the emissions trading scheme and the introduction of carbon prices, must now become a tool to display dirtier coal plants in favor of renewables. In respect to imported hydrogen, the EU carbon border adjustment mechanism will put another layer of complexity on top of the ones driving local markets. In respect to hydrogen, such border adjustment mechanism must achieve an equal import price for ammonia and methanol, irrespective of the 'color' how it was produced and thus lead to a convergence of the costs of green, blue or grey hydrogen carriers at the arrival point in European ports and to create a level playing field between imports and domestic production.

If indeed RES developers and clean hydrogen producers and marketeers start exploring a transition system that builds on a rapid expansion of clean renewables, a prolonged period of higher and more volatile power prices, in an environment that create both more uncertainties and risks but also more opportunities and flexibility, it is well possible that we will gradually move to a contracted pricing system, underpinned by corporate PPAs (Power Purchase Agreements). Such long-term PPA contracts would eliminate the power price risk at the back of these projects. It would also mean that price risk will end with the electrolyzer company and the clean hydrogen (carriers) marketeers and trading houses. This is different than historically in the oil and gas industry where the profit zone is generally in the upstream part of the value chain, and the segment that bears the biggest part of the (commodity) price risk. However, if the electrolyser company is not willing to take this risk, and gives preference to a utility type of role (like the U.S. LNG liquefaction plants), it then also needs to sign HPAs (Hydrogen Purchase Agreement) with a customers. This would extend the contracted pricing system further out to the downstream part of the value chain. Particularly in retail markets, governments might want to (partly) regulate such contracted pricing system, in line with their wish to keep prices low and stable. The rising share of fixed cost power generation sources (wind, solar, nuclear and hydro) is then expanded towards (clean) hydrogen, irrespective an electrolyzer plant is comparable to a refinery, converting one product (slate of crude oils; electrons) into another slate of products (oil products; hydrogen, green ammonia, methanol, LOHC, or SAF). In a world where corporates attempt to secure long-term electricity at low/fixed prices, the PPA market could expand significantly, thus benefiting the acceleration in the development of (cheap/fixed cost) renewables [27]. To allow such evolving system to work well, there is also a growing demand for back-up facilities, through a combination of a number of thermal (CCGT) power plants (and eventually hydrogen turbines), mega-watt battery energy storage systems (BESS), and hydrogen underground storage in caverns. Electrolyzer companies might also build or contract power and/or hydrogen storage facilities for balancing supply and demand and for commercial and risk management purposes. In the Netherlands, the state-owned power grid operator TenneT has estimated that the country needs c. 9 GW of batteries by 2030 to balance the grid (Exhibit 30) [28]. There is also a need to have a part of the RES to be merchant. Today, c. 20-30% of the RES are remunerated on a merchant basis. The 70-80% of the RES are remunerated under contracts with c. 15 year duration [27]. In addition, how such new transition system would evolve is also dependent on the development of hydrogen exchanges, which will be described further below.

Exhibit 30: 9 GW of BESS batteries required by 2030 to balance the grid in Netherlands

Finally, with the aggressive roll-out or RES in the next 10 years, prices determined in a marginal pricing system or in a contracted pricing systems are expected to converge. Of course, this will become dependent on many factors, including those that drive power prices in a marginal system:

1. Commodity costs (gas or coal)
2. Carbon prices
3. Supply/demand balances
4. Share of cheap, fixed cost technologies such as hydro, nuclear, wind and solar
5. Any levies introduced on marginal, price-setting power plants

4. Chapter 4

4.1 The outlook for clean hydrogen

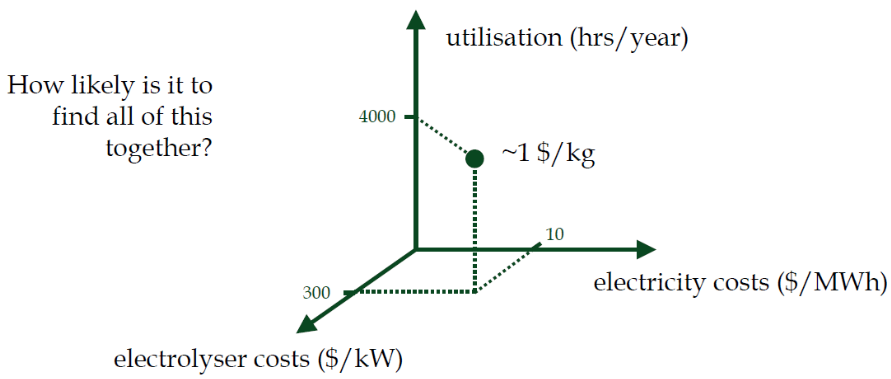
Since 2020, clean hydrogen has gained strong political and business momentum and emerged as a major component in government's net zero plans such as the European Green Deal. The clean hydrogen value chain came back in focus after three false starts in the past 50 years. On the back of this strong momentum, in the second half of 2020, investment banks' research analysts started to write about clean and green hydrogen. Titles of reports were amongst others: 'Carbonomics: The rise of clean hydrogen' [29]. 'Revolutionary road or just a road map. Is hydrogen the green fuel we've been looking for?' [30], 'Green Hydrogen, driver of the utility industry.' [31], 'Hydrogen investing by Hydrogen's insiders. The hydrogen opportunity through industrial gases' lens.' [32]. Also industry research companies started to publish reports on this topic on a regular basis [33].

In October 2019, the green hydrogen pipeline consisted of 3.2 GW of electrolyzer deployments. In August 2020, that pipeline already increased to 15 GW. At that time 22 x 100 MW+ green hydrogen projects had been announced, which in total include targets for 48 GW of electrolyzer deployments by 2030. The largest ever project of 20 MW was expected to be completed by year-end in August 2020. The largest project ever (1.3 GW) was just proposed. It was then estimated that green hydrogen production costs will fall up to 64% by 2040 versus 2020 and will equal fossil fuels based (grey/brown) hydrogen by that year.

In 2020, global average on-site green hydrogen production costs for a 2 MW electrolyzer ranged from $ 10.60/kg and $ 2.06/kg with an average of $ 6.08/kg [33]. This was expected to decrease to $ 5.58/kg (for 2 MW), $ 1.40/kg (for 20 MW), and on average $ 3.48/kg, respectively in 2030, and $ 2.70/kg on average in 2040. The levelized cost of hydrogen production (LCOH) as presented in the table below, is of course largely determined by the assumed electricity price (i.e. cost of electricity), and the utilization rate (10% load factor for high cases; 50% load factor for low cases), in addition to the CAPEX cost reductions (i.e.

the cost of the electrolyzers and related infrastructure costs). Together this gave the high – low range as presented below in the table (Exhibit 32). The ultimate price of green hydrogen is thus determined by three factors along three axes, which makes it difficult to assess the price of hydrogen (Exhibit 31) [34]. The consequence of this complexity is that chosen input assumptions define estimated LCOHs, which could vary widely and can create false expectations of the true costs, and revenue and profitability potential over time. Also a lot of the infrastructure costs are socialized in Europe and not reflected in LCOEs and LCOHs. Hence all-in cost for hydrogen can be significantly higher than the production costs generally published.

Exhibit 31: The $ 1/kg hydrogen challenge [34]



Wood Mackenzie concluded that sub $ 30/MWh renewable LCOEs are needed for green hydrogen to become competitive. On their assumptions, this could occur by 2030. At an electricity price of $ 30/MWh and a 50% load factor, the LCOH hydrogen price would be $ 1.94/kg according their calculations. This could be competitive in China, Japan and certainly in Europe with grey hydrogen where the price outlook is mostly tied to forecasted natural gas prices. Lower gas prices in the U.S. requires more policy stimulus to make green hydrogen more competitive. Blue hydrogen deployment might take the lead in the U.S. in the earlier years. Arbitrage opportunities however might make green hydrogen (carriers) export out of the U.S. possible. Also carbon prices, only assumed for Germany and Japan in the table below, would impact the level of competitiveness.

The European Commission’s hydrogen strategy at that time included a 1 million tonne annual green hydrogen production in Europe by 2030 and 10 million tonne by 2040. Germany committed Euro 7 billion to ramp up hydrogen technology and announced a target of 5 GW of green hydrogen production by 2030. Wood Mackenzie estimated that green hydrogen production in Europe was 0.05 million tonne in 2020. The green hydrogen project pipeline consisted of 3.2 GW of electrolyzer deployment late 2019. 10 months later this had already ballooned to 15 GW. They estimated that the global electrolyzer manufacturing capacity was approximately 150 MW at a capex cost of $1,162/KW for PEM and $ 978/KW for Alkaline. They estimated that this would decrease to a capex cost of $912/KW for PEM and $ 677/KW for Alkaline by 2025 and to $687/KW for PEM and $ 569/KW for Alkaline by 2030.

Exhibit 32: Price forecasts (August 2020) [33]

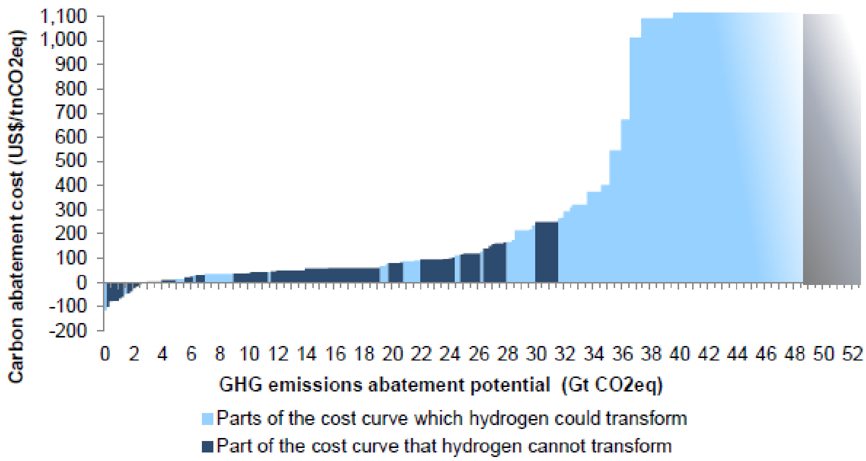
		2020	2025	2030
global average green hydrogen costs without direct subsidies	high	$ 11.11/kg	$ 6.24/kg	$ 5.06/kg
	average	$ 6.86/kg	$ 3.93/kg	$ 3.23/kg
	low	$ 2.60/kg	$ 1.61/kg	$ 1.39/kg
U.S. LCOH green hydrogen costs	high	$ 10.10/kg	$ 7.42/kg	$ 6.08/kg
	average	$ 6.71/kg	$ 4.73/kg	$ 3.94/kg
	low	$ 3.32/kg	$ 2.05/kg	$ 1.79/kg

Germany LCOH green hydrogen costs	high	$ 14.74/kg	$ 7.24/kg	$ 5.84/kg
	average	$ 8.82/kg	$ 4.53/kg	$ 3.70/kg
	low	$ 2.91/kg	$ 1.82/kg	$ 1.56/kg
Japan LCOH green hydrogen costs	high	$ 10.60/kg	$ 6.29/kg	$ 5.09/kg
	average	$ 6.59/kg	$ 3.95/kg	$ 3.23/kg
	low	$ 2.58/kg	$ 1.60/kg	$ 1.38/kg
Saudi LCOH green hydrogen costs	high	$ 9.49/kg	$ 6.02/kg	$ 4.92/kg
	average	$ 6.07/kg	$ 3.83/kg	$ 3.18/kg
	low	$ 2.65/kg	$ 1.63/kg	$ 1.43/kg
China LCOH green hydrogen costs	high	$ 7.86/kg	$ 5.79/kg	$ 4.78/kg
	average	$ 5.28/kg	$ 3.73/kg	$ 3.12/kg
	low	$ 2.70/kg	$ 1.66/kg	$ 1.46/kg

Blue hydrogen was estimated at $ 1.90/kg and grey $ 1.12/kg in 2030. In 2020, it was thus expected that Germany will be the first market to see competitive green hydrogen costs, while in the U.S. grey hydrogen will be the lowest cost color for the foreseeable future. Of course, this has changed materially since then since IRA, which would have a positive impact. Cost inflation and higher interest rates, however, will push the LCOH up again.

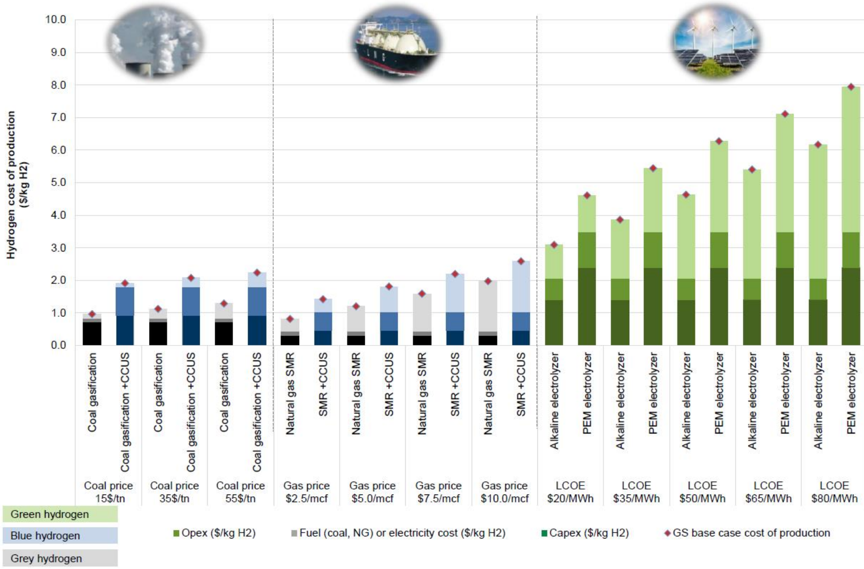
Goldman Sachs wrote in July 2020 [29]: Clean hydrogen has a major role to play in the path towards net zero carbon, providing de-carbonization solutions in the most challenging parts of the Carbonomics cost curve – including long-haul transport, steel, chemicals, heating and long-term power storage (Exhibit 33). Clean hydrogen cost competitiveness is also closely linked to cost deflation and large scale developments in renewable power and carbon capture (two key technologies – green and blue – to produce it), creating three symbiotic pillars of de-carbonization.

Exhibit 33: Carbon abatement cost ($/tnCO2eq) vs GHG emissions abatement potential (GtCO2eq) [29]



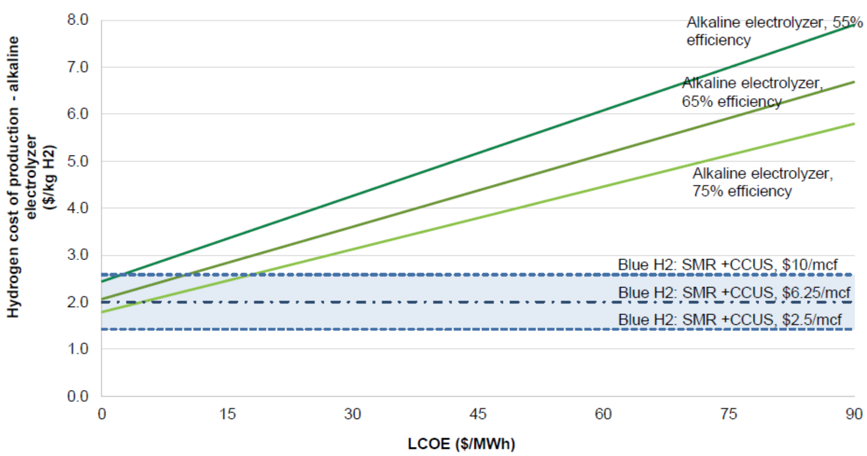
Whilst blue and green hydrogen are the lowest carbon intensity hydrogen production pathways, both of these technologies are more costly when compared to the traditional hydrocarbon-based grey hydrogen production (Exhibit 34). As mentioned earlier, the costs of producing green hydrogen is primarily related to the capex of the electrolyzer, the electrolyzer's conversion efficiency, load hours and, most importantly, the cost of electricity, which makes up c. 30-65% of the total cost of production depending on the levelized cost of electricity (LCOE). Of that electricity, around 35% of the energy is 'lost' in electrolysis. Hence it was then concluded that green hydrogen definitely needs cheap power (preferably zero or negative cost).

Exhibit 34: Hydrogen cost of production under different technologies & fuel prices [29]



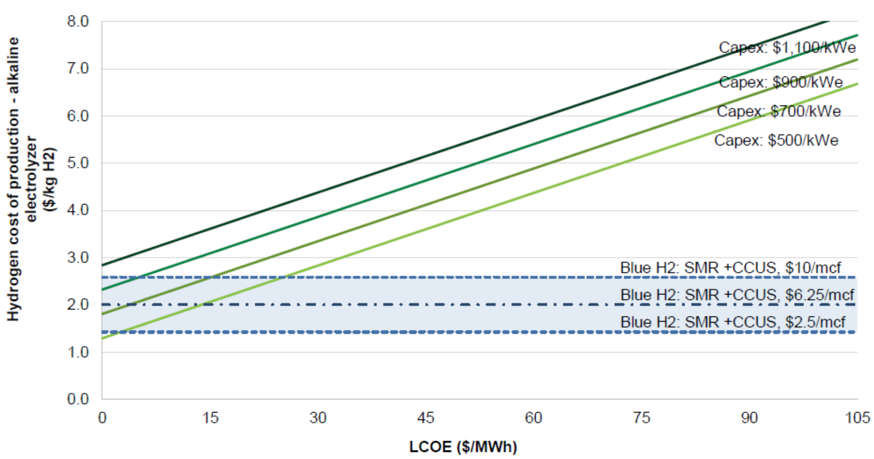
In Exhibit 35 the estimated costs of the hydrogen cost of production (using the simplest, lower cost and most widely adopted alkaline electrolysis route) for different costs of electricity (LCOE) and for different electrolyzer efficiencies are presented. The analyses conducted by Goldman Sachs at that time implied that the cost of electricity required for green hydrogen to come into cost parity with high-cost blue hydrogen needs to be on the order of $ 5-25/MWh LCOE assuming that the electrolyzer and carbon capture technologies capital costs remain at the current level (only electricity cost varies along the green hydrogen lines and natural gas cost varies along blue hydrogen lines), assuming an alkaline electrolyzer efficiency of 55-75%.

Exhibit 35: Hydrogen cost of production ($/kg H2) vs LCOE ($/MWh) [29]



The cost of the electrolyzer also impacts the overall cost of producing green hydrogen, with a LCOE of <$30/MWh required for electrolyzers with a capex exceeding $ 500/kWe to reach cost parity with high cost blue hydrogen (Exhibit 36).

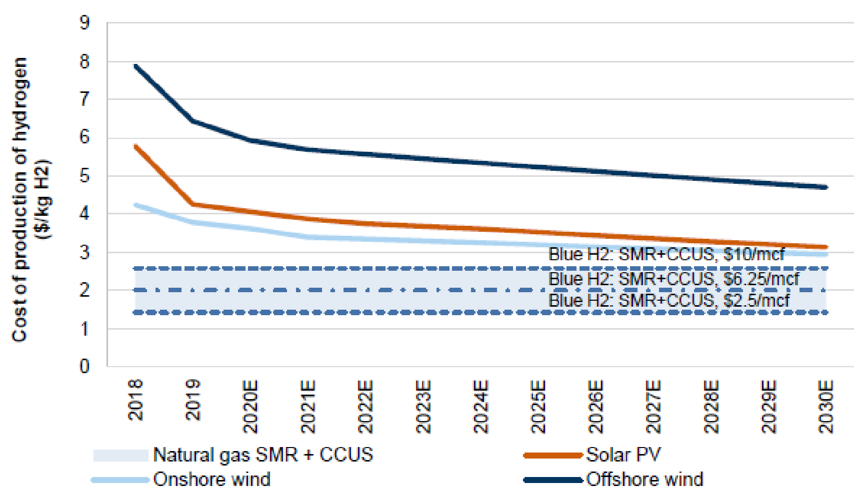
Exhibit 36: Hydrogen cost of production ($/kg H2) vs LCOE ($/MWh) [29]



As mentioned earlier, the LCOE range for offshore wind globally was c. Euro 80-90/MWh last year [23]. This is in line with the earlier mentioned prediction that offshore wind LCOE could further rise to Euro 90/MWh in 2024 and stay there for the foreseeable future [17]. The earlier described one-gigawatt green hydrogen plant has a CAPEX of Euro 730-830/kW ($ 795-904/kW). This corresponds best with hydrogen cost of production of $ 7/kg.

Based on those parameters in the middle of 2020, the global average LCOE for renewables implied that onshore wind and low cost solar PV could reach cost parity with high cost blue hydrogen ($ 10/mcf gas price) by 2030E, accompanied by a reduction in electrolyzer costs (Exhibit 37). Taking the CAPEX and LCOE prices of today into account, the costs of production in 2023 presented in the exhibit below seems to be too low. Today it seems we are still in 2018 with respect to production costs. The main cause are higher electricity prices, cost inflation and slower process towards final investment decisions today.

Exhibit 37: LCOH ($/kg H2) implied in the cost of production for hydrogen through [29]



Apart from the electrolyzer efficiency and the cost of electricity (LCOE), the full load hours of operation of the electrolyzer will also have a notable impact on the overall cost of producing hydrogen. Exhibits 38 and 39 show estimated variation in the cost of production of hydrogen with the full load hours for an alkaline and a PEM electrolyzer, respectively. The charts indicate that for full load hours >5,000 (representing 57% of total annual hours working at full capacity), the cost of production curve flattens and the cost of production is no longer materially impacted by the full load hours. On other words, the full load hours of the electrolyzer has a notable impact on the cost of production if <5,000, but cost of production becomes flatter after that for both type of electrolyzers.

Exhibit 38: Hydrogen cost of production vs alkaline electrolyzer full load hours [29]

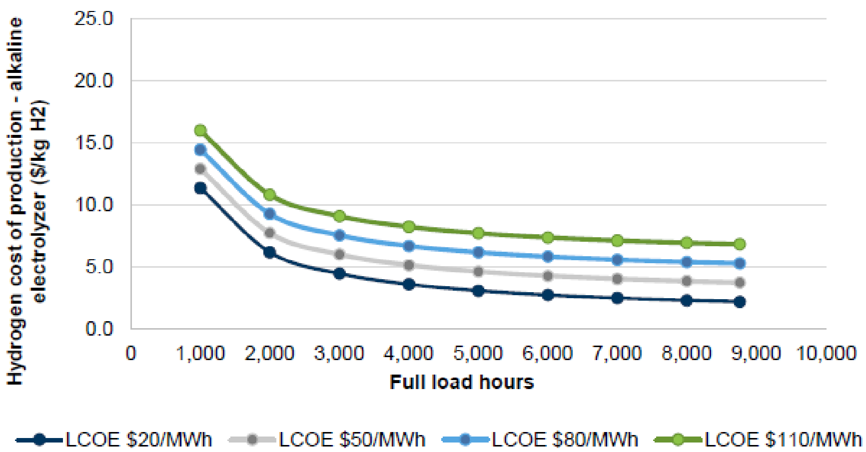
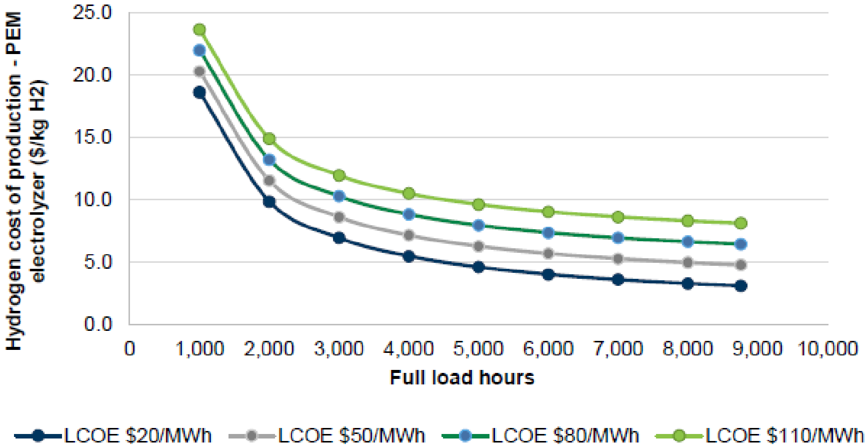


Exhibit 39: Hydrogen cost of production vs PEM electrolyzer full load hours [29]



The analysis also showed that the cost of production has a linear correlation with electrolyzer CAPEX for both alkaline and PEM electrolyzers, as shown in Exhibits 40 and 41. It was noted that the implied cost per electrolyzer has the potential to reduce when using larger multi-stack systems which involve combining several electrolyzers stacks together. This, along with technological innovation and economies of scale, are the key potential areas of cost reduction.

Exhibit 40: Hydrogen cost of production vs alkaline electrolyzer capex ($/kg H2) [29]

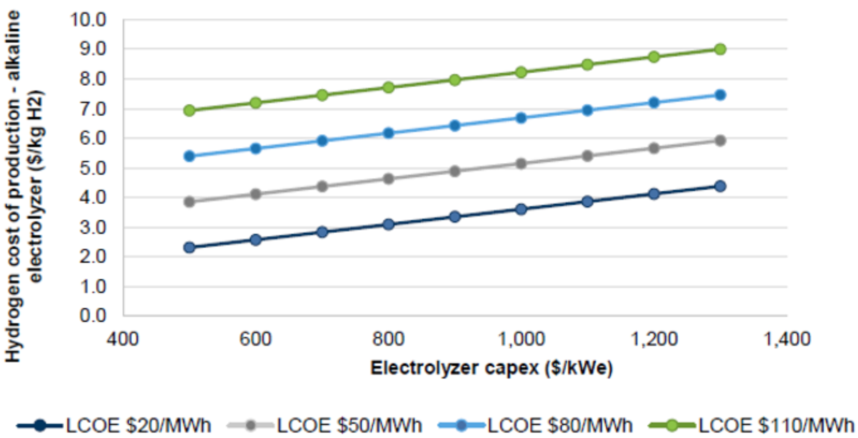
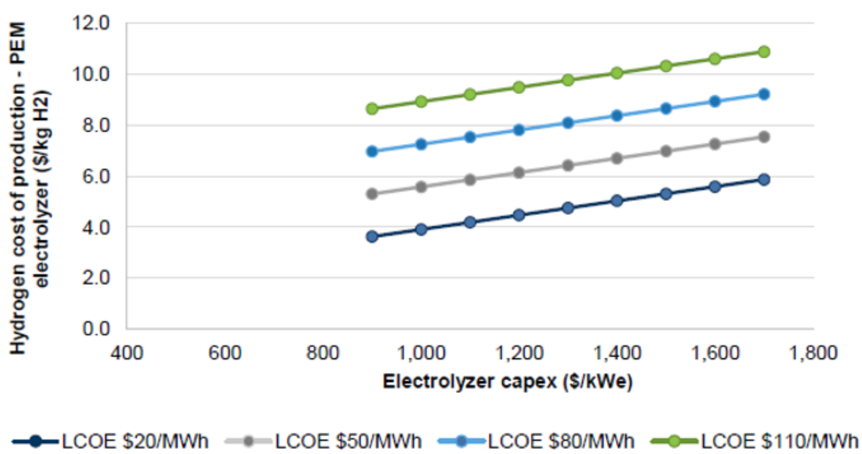


Exhibit 41: Hydrogen cost of production vs PEM electrolyzer capex ($/kg H2) [29]

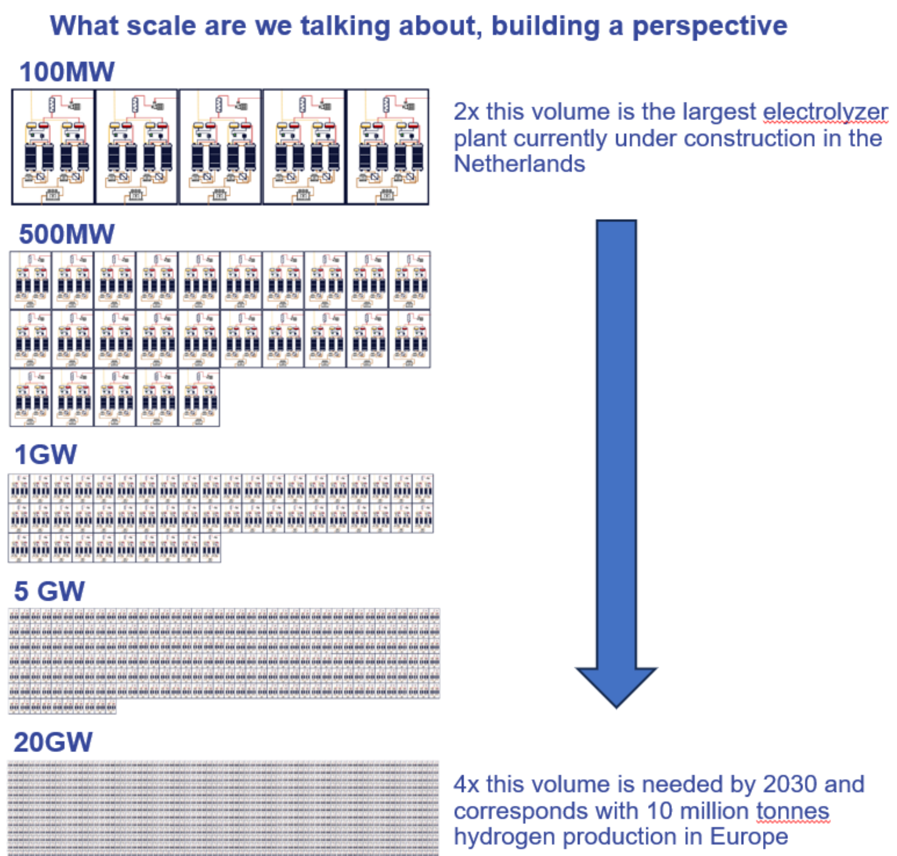


The earlier described one-gigawatt green hydrogen plant has a CAPEX of Euro 730 – 830/k ($795 – 904/kW). Today's wholesale power prices in Northwest Europe is approximately Euro 100-110/MWh. LCOE price forecast for the coming years is Euro 70-90/MWh, This points to a hydrogen cost of production of c. $ 7 – 8/kg pending the load factor.

On July 8, 2020, the European Commission published its 2030 Hydrogen Strategy. This was the first, concrete document which details the central role that hydrogen is to play in the European economy. The EU Hydrogen Strategy underpinned the birth of an entirely new hydrogen industry largely based on green hydrogen: against an electrolyzer installed base of 0.1 GW in 2020, the EU targets 6 GW of electrolyzer capacity been built by 2024. For the second phase, covering 2025 and 2030, the EU targets the installation of at least 40 GW of electrolyzers within the EU (producing about 5 million tonnes of renewable hydrogen) and in addition deploying capacity in and sourcing imports from neighboring countries totaling ca. another 40 GW in electrolyser capacity by 2030 to be able to utilize up to 10 million tonnes of clean hydrogen based upon an estimated demand of up to 10 million tonnes per year of renewable hydrogen in the EU by 2030. The European Commissions also announced its working assumption of 500 GW of electrolyzer capacity being available by 2050. Based on the this EU hydrogen strategy, there would be a 650x increase in the European electrolyzer market by 2030 versus 2020 [31].

The 40 GW installed capacity of electrolyzers, leading to 5 million tonnes of clean hydrogen produced on the EU territory, is based on 4,162 hours equivalent and the energy content of hydrogen c. 33,3 kWh/kg H2. 10 million tonnes hydrogen demand is equivalent to 333 TWh. Its requires 52 MWh of electricity to produce 1 tonne of renewable hydrogen: Electrolyzers have efficiencies that typically require c. 52 kWh of clean electricity per kg of clean hydrogen (c. 52 MWh/tonne), and it takes more energy to produce hydrogen (52 kWh/kg) than the end-use energy that the hydrogen provides (c. 33 kWh/kg), and thus the theoretical maximum potential efficiency that can be achieved. Thus to reach the 10 million tonnes domestic target, a substantial amount of additional renewable electricity (c. 500-550 TWh) will be needed to produce renewable hydrogen (on top of the large amounts of renewable electricity that will be needed to electrify applications that are currently served by other energy carriers) and to achieve 55% CO2-emission reduction in Europe by 2030. In exhibit 42 below a sketch is presented how many electrolyzer stacks – each box representing 4x 5 GW stacks – are needed to grow from the 200 MW electrolyzer currently built by Shell in Rotterdam to the number representing Europe's target.

Exhibit 42: Europe's ambitions (source HyCC)



To put this in perspective, if we were to replace all the hydrogen currently produced worldwide (c. 79.5 million tonnes expected demand in 2023 [35]) with green hydrogen, the new supplies of electricity would exceed the power consumption in Europe (c. 3,500 TWh in 2020). Likewise, European Commissions' original 2030 target of 5 million tonnes of hydrogen production requires c. 250 TWh, or c. 7% of current electricity demand in Europe. The current target of 10 million tonnes by 2030 corresponds thus with c. 14% of Europe's electricity demand. This is a significant share and will impact the price discovery process if indeed this target is met successfully by 2030. Clean hydrogen is then able to replace most of Europe's current hydrogen demand produced from fossil fuels – the substitution phase.

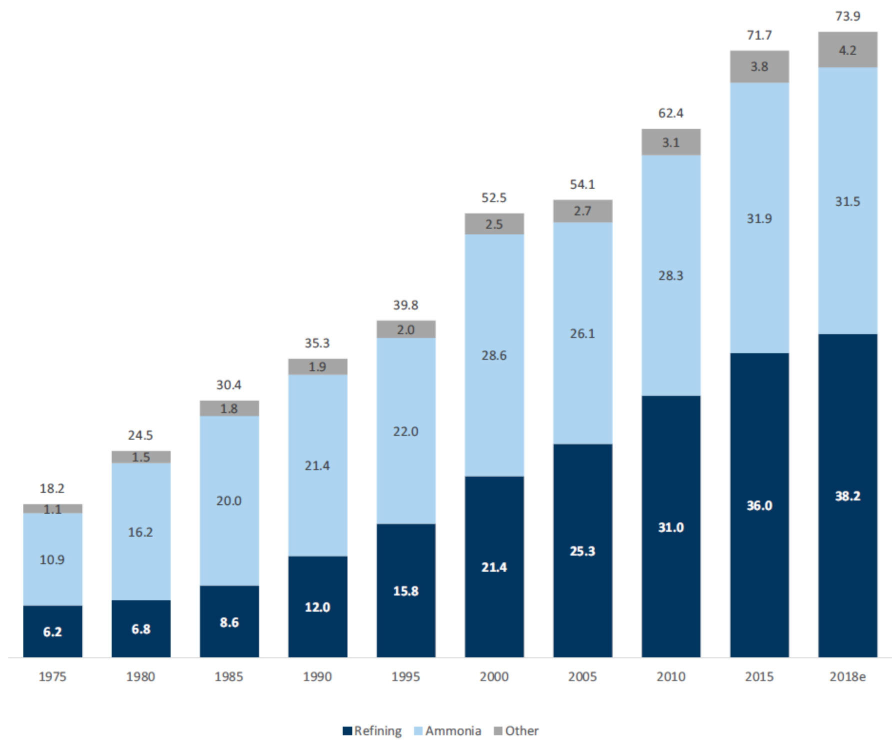
Replacing natural gas and oil products by clean hydrogen in various sectors requires more clean hydrogen – the growth phase. The working assumption for 2050 (500 GW of electrolyzer capacity / 62.5 million tonnes of hydrogen) translates into an additional power consumption of 3,300 TWh. Under such bull case scenario of 500 GW of electrolyzers, it has been estimated that c. 1,100 – 1.300 GW of dedicated RES capacity would be needed to meet the additional power demand (c. 3,300 TWh). Power demand for electrolysis alone could double European electricity consumption and green hydrogen could become the largest electricity customer. This would result in an installed base of RES of nearly 2,600 GW in the European Union and requires a doubling of the annual RES capacity additions from c. 35 GW/yr under the EU Green Deal scenario to c. 90 GW/yr.

The report also presented three scenarios for green hydrogen: (i) electrolysis from 100% Southern European solar, which is currently the cheapest form of renewable energy; (ii) electrolysis from 100% offshore wind, which is at the moment the most expensive form of renewable energy; and (iii) electrolysis from a blend of RES sources: offshore wind 40%, solar 40% and onshore wind 20%. By 2030, it was estimated that the LCOH of green hydrogen produced from solar in Southern Europe (Spain; the cheapest RES source) would become more competitive, at less than Euro 2/kg. 100% offshore resulted in a LCOH of Euro 3.3/kg, and a blended RES Euro 2.6/kg. This is materially lower than presented by Wood Mackenzie in exhibit 32 earlier in this report.

Based on 2018 data, global pure hydrogen demand was 74 million tonnes [29]. For 2023 a demand of 79.5 million tonnes is expected [35]. Approximately 76% was made from natural gas and almost all the rest (23%) from coal. To create 74 million tonnes of hydrogen, 290 Mt or 2% of primary energy demand was required and resulted in a total CO2 emissions footprint of 877 Mt CO2, which is roughly equivalent to the combined CO2 emissions of Indonesia and the UK (IEA, 2019). Ammonia, refining and petrochemicals (methanol) consumed more than 95% of this (c. 38%, 41% and 15% respectively). Iron and steel the remaining 6%. Actually, the market for hydrogen saw a steadily growth over the years (Exhibit 43). Europe's demand is estimated to be c. 20%. This means that Europe consumed about 15 million tonnes of pure hydrogen (based on 2018 data). However, also other demand volumes are mentioned, ranging from a low of 8.7 million tonnes expected in 2023, 10 million tonnes and 24 million tonnes in 2020, besides the 15 million tonnes. One reason is the difference between pure hydrogen and hydrogen that is mixed with carbon-containing gases in methanol production and steel manufacturing, as well as hydrogen in residual gasses from industrial processes used in heat and electricity generation.

The IEA quotes the following numbers in its latest global hydrogen review 2022 [36]: Global hydrogen demand reached more than 94 million tonnes in 2021, including more than 70 million tonnes of pure hydrogen and more than 20 million tonnes mixed with carbon-containing gases in methanol production and steel manufacturing, but excludes c. 30 million tonnes present in residual gases from industrial processes used in heat and electricity generation. They exclude the latter because this use of 30 million tonnes is linked to the inherent presence of hydrogen in these residual streams, rather than to any hydrogen requirement. These gasses are not considered here as hydrogen demand. Nevertheless, the range of current demand is large, more than 10 million tonnes. According the IEA, China is the world's largest hydrogen consumer with demand in 2021 of c. 28 million tonnes. The U.S. is the second-largest and the Middle East the third-largest consumer at c. 12 million tonnes each. Europe is the fourth-largest with demand of more than 8 million tonnes in 2021. India is next with demand of 8 million tonnes hydrogen. The top 5 regions / countries consume c. 68 million tonnes of the global demand of 94 million tonnes of hydrogen in 2021 (73%). Based on a demand of 8-9 million tonnes in Europe and would the 10 million tonnes of production be met by 2030, it implies that all of today's demand could be replaced by clean hydrogen.

Exhibit 43: Global demand for pure hydrogen by sector in million tonnes [29]



In 2020, green hydrogen electrolysis was (and still is) a very niche technology, with an installed base of just over 100 MW, of which c. 60% located in Europe. However, the technology is set for rapid growth. In 2020, the IEA published the following list of announced projects that are commissioned this decade (Exhibit 44).

Exhibit 44: Announced project capacity to be commissioned globally between 2021 and 2030 (IEA, 2020) [29]

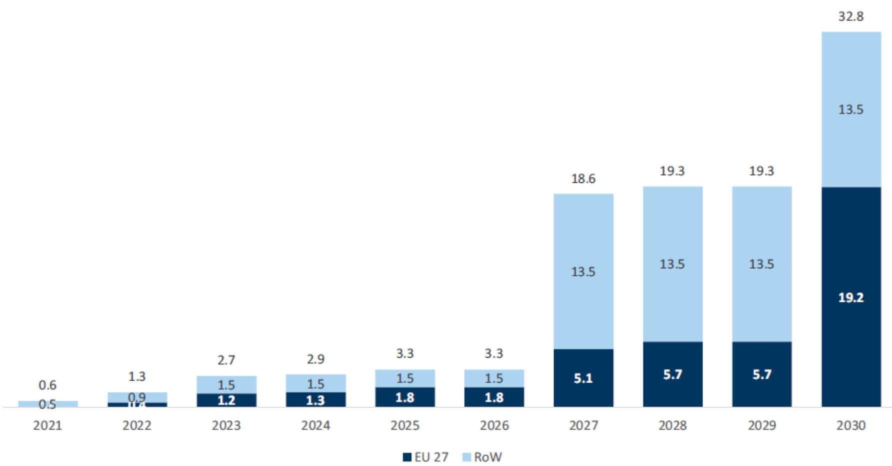
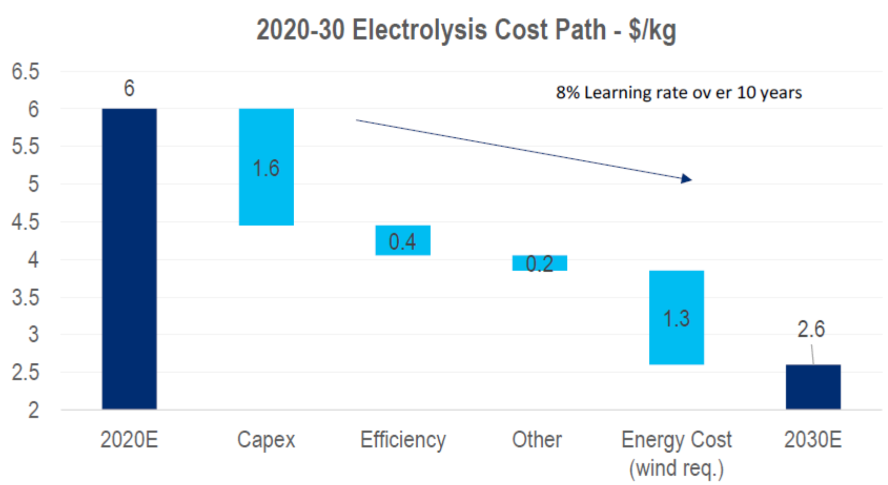


Exhibit 45: The variance of renewable hydrogen costs with power prices, capex costs and load factors [32]

The earlier described one-gigawatt green hydrogen plant has a CAPEX of Euro 730-830/kW ($ 795-904/kW). This corresponds best with the left part of the exhibit. Today's wholesale power prices in Northwest Europe is approximately Euro 100-110/MWh. This points to a green hydrogen price as per the bottom line of the chart, Between $ 6 and 6.5/kg pending the load factor.

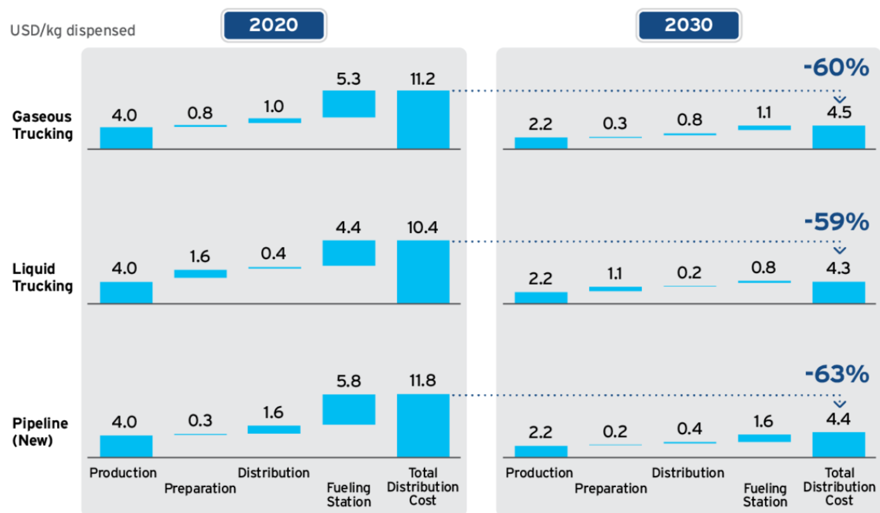
According Citi in 2020, the primary issues related to cost are 1) access to cheap renewable power and 2) scale. The aim of the EU is to achieve a cost of $ 2-2.5/kg. In order to achieve this, the Hydrogen Council indicated that costs are going to have to reduce to $ 400/kW. According the council in 2020, this is thought to be achievable with a 9-13% learning rate on 70 GW of capacity (Exhibit 46) over the period until 2030. Given the EU's ambitious plans of 40 GW of capacity by 2030, Citi believes that we are realistically looking at closer to 2040 before the construction costs are going to make hydrogen economically competitive [32]. This supports their thinking that projects will be end-to-end, where the consumer is willing to pay. This should lead to a set of discrete projects that demand renewable hydrogen. Alternatively governments must be willing to subsidize both the CAPEX and the OPEX to initiate the system. Over time, these projects might start to integrate into a broader hydrogen network.

Exhibit 46: Learning rates of 8% expected in the near-term (October 2020; source McKinsey) [32]



Moreover, most of the hydrogen business conducted currently operates off the pipeline networks to large industrial customers in vicinity of the production unit (either on-site within the fence of the industrial complex, or within the port). Prices mentioned are wholesale production prices. Hydrogen at a filling station is likely to be produced on-site by a mini-plant. It could also be trucked in a gaseous or liquid state. This will add costs, as shown in exhibit 47. [30]

Exhibit 47: Total distributed fuel costs (October 2020; source McKinsey) [32]

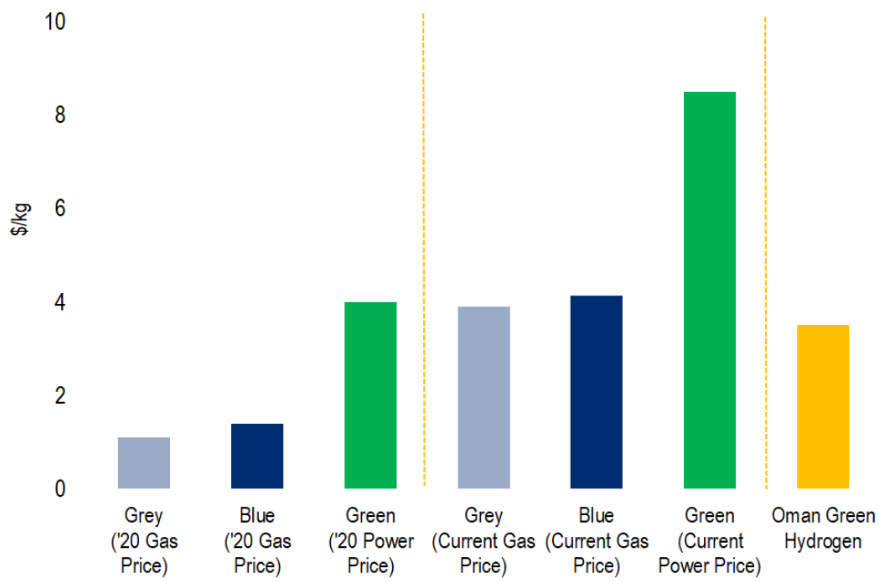


In June 2023, the price at filling point was Euro 21.60/kg ($ 23.54/kg) in the Netherlands, i.e. twice as expensive as the above 2020 numbers and substantially higher than in the U.S. Again, the price of natural gas was the biggest game changer.

In September 2021, when natural gas prices started to rise significantly, Citi made an interesting point [37]. 'An overbuild of renewables looks critical to any pathway for competitively priced green hydrogen in fulfilling Europe's 10 million tonnes per annum by 2030 target. The current power system, where prices look to fluctuate wildly as gas generation sets the marginal economics, looks ill-suited to making green hydrogen a fuel of choice. In Europe, marginal power prices are also set by gas generation. And this price-setting mechanism has been highly visible in 2021, with rising natural gas prices seeing European power prices more than double. Based on current power prices, European green hydrogen is highly uncompetitive (Exhibit 48).' Note that the today's natural gas price in

Europe in 2023 has come down spectacularly, c. a third lower than in September 2021, but still more than 3x higher than 2019 prices.

Exhibit 48: European Grey, Blue and Green Hydrogen Economics at Current/Previous (2021/2020) Gas and Power prices [32]

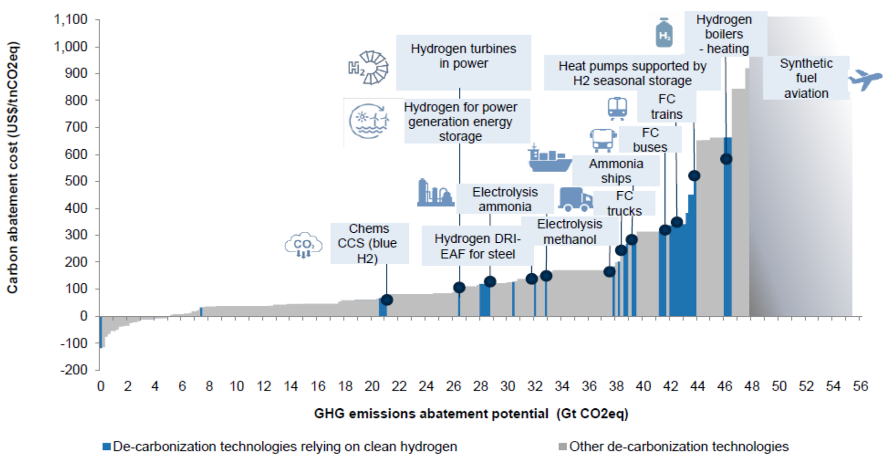


They conclude that green hydrogen is really most suited to regions of the world where renewable resources have high yields, and can be overbuilt relative to the pull from domestic electricity demand. As an example they highlighted the Duqm project in Oman. With plenty of solar and wind resources available, hydrogen and then converted into green ammonia can land into Europe at a hydrogen-equivalent price of $ 3.5-4.0/kg. Carbon prices above $ 100/tonne could then help bridge down to $ 2/kg, a level that is probably competitive for a lot of industry.

Many of the data and calculations have been regularly updated since then. As can be seen in exhibit 49, the abatement cost curve is steep as we move beyond 50% de-carbonization, calling for technological innovation and breakthroughs to unlock the net zero carbon potential. Clean hydrogen is at the forefront of this technological challenge: based on

Goldman Sachs' analysis, it has the potential to transform 15%/20% of the total global GHG/CO2 emissions and can be attractively positioned in a number of transportation, industrial, power generation and heating applications [38].

Exhibit 49: **2021 Carbonomics cost curve with technologies relying on clean hydrogen indicated–- carbon abatement cost ($/tnCO2eq) vs GHG emissions abatement potential (GtCO2eq)** [38]



With all the uncertainty and interdependencies, global demand for hydrogen is difficult to predict, irrespective of all policy ambitions. In Goldman Sachs' three scenarios, global hydrogen demand will increase at least 2-fold by 2050. In their optimistic scenario up to 7-fold (Exhibits 50). Their base case forecasts a hydrogen demand of c. 130 million tonnes by 2030 and c. 190 million tonnes by 2035, growing further to 370 million tonnes by 2050. In each of the three scenarios the combined hydrogen demand of refineries, ammonia and methanol is equal. Growth will start to come iron and steel, and even more from transport and power generation. There exist a wide range of potential hydrogen demand scenarios, released by a number of agencies and investment banks. Their 2022 forecasts are presented in exhibit 51.

Exhibit 50: Global hydrogen demand under the three GS net zero models (in million tonnes H2) [38]

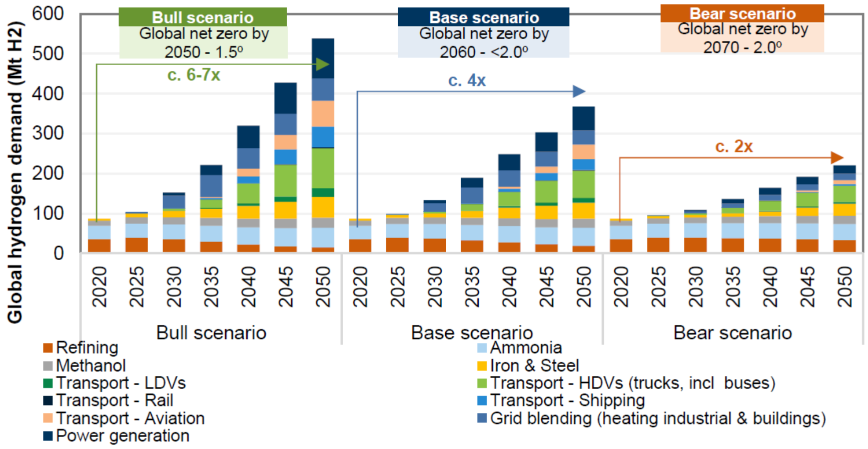
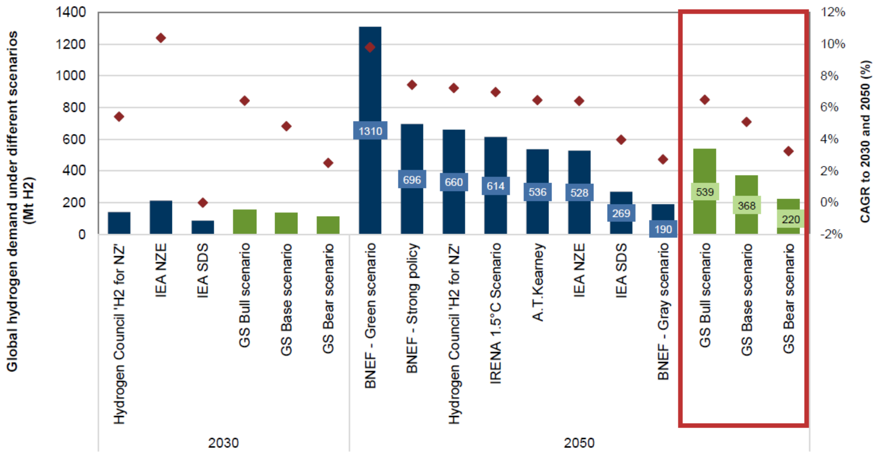
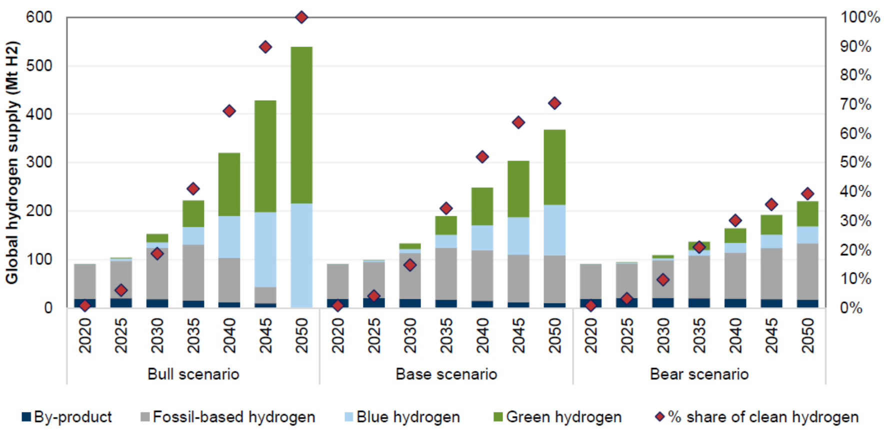


Exhibit 51: Global hydrogen demand under different scenarios (in million tonnes H2) [38]



In exhibit 52 the different sources (colors) of supply are presented. In each scenario the majority of demand will still be supplied by grey hydrogen until 2035. Pending which scenario you choose, clean (blue and green) hydrogen takes a 22% to 42% market share by 2035. Our expectation is that, differently than presented in the exhibit, the first developments will be mostly clean-for-grey hydrogen substitution in the forementioned industries. In such case, first developments will thus concentrate on reducing scope 1 and 2 GHG emissions in those industries. Together 10 to 30 million tonnes of grey hydrogen of the 90 million tonnes can be replaced by clean hydrogen by 2030. It is equally interesting to see how the other industry sectors and notably hydrogen in mobility are going to develop. The delta between the bull and bear cases is about 40 million tonnes of demand in 2030, and 90 million tonnes by 2035. Thus while clean hydrogen is a necessary pillar to any aspiring net zero path, the pace and extent of hydrogen penetration is far from certain. Key drivers that ultimately influence the penetration of clean hydrogen are a) the price of electricity for hydrogen production; b) the CAPEX cost of the electrolyzers and related infrastructure and the pace of unit cost improvements through technical innovation and wider adoption and the counter force of cost inflation; c) the cost associated with hydrogen adoption compared to alternative technologies (e.g. electric powered trucks); d) returns and attractiveness for investors and financiers; e) consistent policy support with long visibility; f) any further improvement expectations in the electrolyzer efficiency and higher utilization; and g) carbon prices.

Exhibit 52: **Global hydrogen supply under different scenarios (in million tonnes H2)** [38]

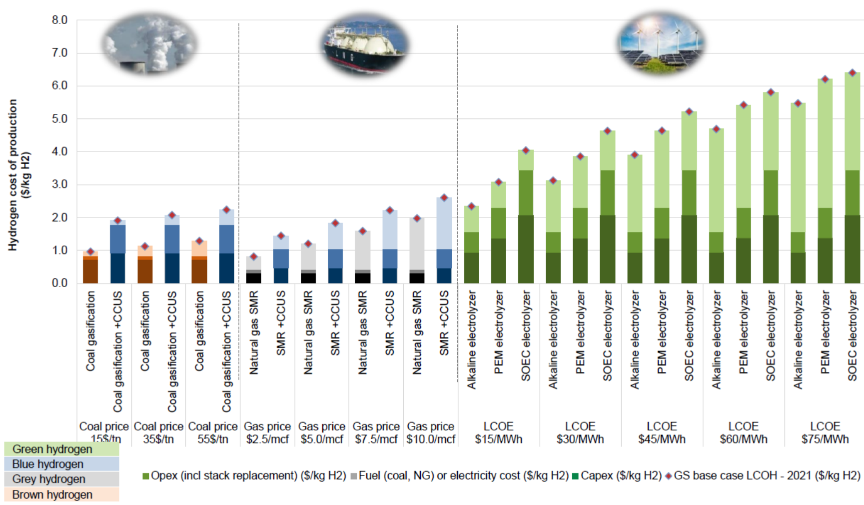


It is important to recognize that supply is not the same as capacity. This is dependent on the load factor for each unit and how that would work out on average. Goldman Sachs estimates that between 65 GW and 180 GW of electrolyzer capacity is globally needed by 2030 (or 325x to 900x of Shell's 200 MW plant currently under construction in Rotterdam) and 500 GW to 3,200 GW by 2050 under the three scenarios [38]. This compares to an expected clean hydrogen demand of 10 to 30 million tonnes by 2030 under their three scenarios (65 GW electrolyzers x 5,000 hours/year load factor x 33 MW/ton = c. 10 million tonnes; a load factor of 4,000 hours results in a demand of 80 GW of electrolyzers; likewise 180 GW of electrolyzers corresponds with c. 30 million tonnes of clean hydrogen). The pipeline of projects under construction, FID and feasibility is c. 78 GW by 2030, including c. 27 GW cumulative to 2030 in Europe. The earlier described one-gigawatt green hydrogen plant has an anticipated total investment cost level Euro 730-830/kW ($ 795-904/kW) for AWE and for PEM respectively. A 1-GigaWatt Green Hydrogen plant to be built in the Netherlands between 2028 and 2030 would then cost $ 800 - $ 900 million. If indeed the 200 MW Shell Pernis will ultimately cost $ 1 billion, including all Outside Battery Limits

(OSBL) costs, then a 1-GigaWatt Green Hydrogen plant would cost $ 5 billion today. Based on the 1-GigaWatt Green Hydrogen Plant, the total CAPEX investment in the coming 7 years is between $ 52 billion and $ 162 billion. In a Shell case but now also including a 50% unit cost reduction over this period, the total CAPEX investment in the coming 7 years is between $ 162.5 billion and $ 0.45 trillion. Persistent industry inflation could push this cost estimate up materially. Europe's domestic 40 GW by 2030 production target would cost $ 32 billion (1 GW plant) to $ 80 billion (Shell case/50% cost reduction). Europe's 40 GW overseas plants, taking also all OSBL costs, such as infrastructure, conversion installations, and storage and port facilities into account, will probably go to the upper level of this range.

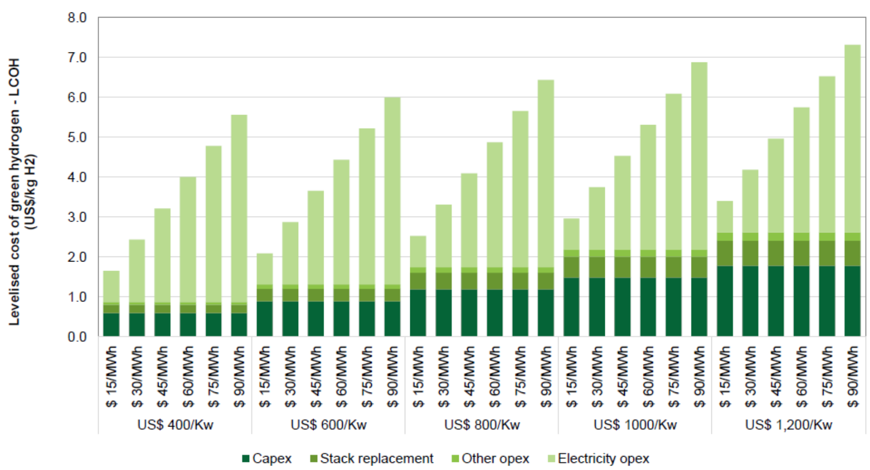
In exhibit 53, an update of exhibit 34 from 2020 is presented. In this exhibit from February 2022 also the production costs based on solid oxide electrolysis cells (SOEC) technology are presented. Unit costs per kg have not changed a lot since then, which is logical as no world-scale electrolyzers have been commissioned during this period. Nevertheless, material cost reductions are expected.

Exhibit 53: **Hydrogen cost of production under different technologies & fuel prices** [38]



Based on an electrolyzer with an efficiency of 64% and operating for 5,000 full load hours per year, an LCOE that is lower than c. $ 30/MWh is required to be at cost parity with blue hydrogen, and lower than c. $ 20/MWh to be at cost parity with grey hydrogen. However, would indeed offshore wind LCOE rise further to Euro 80-90/MWh in 2024 and stays there for the foreseeable future, the levelized cost of green hydrogen (at CAPEX of $ 800/kW) would stay at $ 6.5/kg H2 (Exhibit 54). At such price level, the very first projects require massive subsidies to at least half the LCOH cost. Cost levels presented earlier in exhibits 35 to 41 have improved a bit since 2020, but not yet material. Cost parity of green hydrogen is first expected in the Middle East and Chile where low cost RES is plentifully available, or where gas prices are high, such as in China. This is expected to take place in the 2nd half of this decade. By the beginning of the next decade green hydrogen might become achieve cost parity with blue and grey hydrogen in regions with average RES electricity cost of $ 30-40/MWh, also dependent on regional carbon pricing.

Exhibit 54: **Levelized cost of green hydrogen (LCOH) under various unit CAPEX and levelized cost of electricity (LCOE) scenarios** [38]



As said before, we believe that clean hydrogen begins with the de-carbonization of existing hydrogen end markets to reduce scope 1 and 2 GHG emissions. Therefore, we see the starting point of the clean hydrogen economy as the decarbonization of the c. 10 million tonnes of current dedicated fossil fuel-based hydrogen production in Europe, and c. 70 million tonnes of pure hydrogen preliminary used in oil refining and ammonia globally. Additional end markets will be found in the steel industry and the production of renewable diesel and kerosine (Sustainable Aviation Fuels – SAF).

Oil refining is the largest consumer of hydrogen currently, accounting for c. 41% of global hydrogen demand in 2021 [38]. At a certain moment oil demand enters a period of structural decline, implying lower hydrogen demand for refining. Nonetheless, in the near term, hydrogen demand in oil refining is expected to increase. The production of biofuels and synthetic fuels also requires green hydrogen. Production of advanced biofuels through hydrotreatment (HVO / SAF) is even more hydrogen intense than traditional oil refined products, resulting in further hydrogen demand upside. In aggregate, hydrogen demand in refining is expecting to peak before 2030 and could decrease from c. 38 million tonnes in 2030 to as low as 15 million tonnes by 2050, but could also marginally decrease if the energy transition goes slower than planned.

The chemicals industry consumes about 53% of global hydrogen, primarily as a feedstock for ammonia and methanol production, with both requiring 180 and 130 kg of hydrogen per tonne of product, respectively [38]. As mentioned earlier, the aggregate hydrogen demand in this sector plus in refining is expected to stay flat until 2050. At what price green hydrogen becomes competitive in these industrial sectors is very different per region and highly determined by the combination of RES power prices, natural gas / LNG prices and carbon prices.

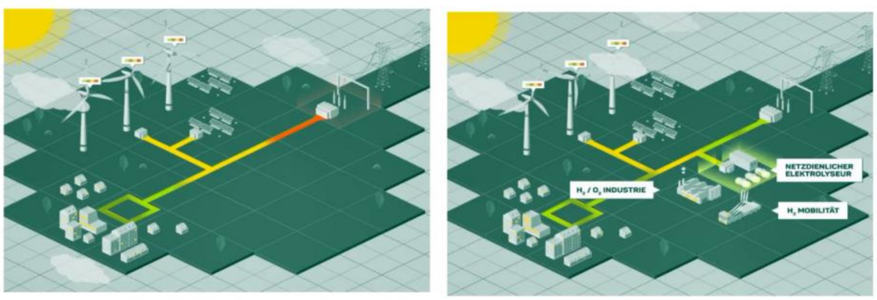
Around 7% of current hydrogen demand (fourth largest single source) comes from the steel industry. Steel manufacturing is also the single highest CO2 emitter among industrial sub-sectors. The European Commission expects that c. 30% of EU primary steel production will be decarbonized with renewable hydrogen by 2030. Based on the earlier presented hydrogen demand scenarios (exhibit 50), global hydrogen demand in steel and iron ranges between less than 5 and more than 15 million tonnes by 2030.

Transportation mostly sits in the high-cost area of the decarbonization cost curve. The mobility sector (cars, light and heavy-duty vehicles, shipping and aviation) ranges between basically neglectable to just 5 million tonnes of hydrogen by 2030. Only post-2030 demand could potentially rapidly increase in the transportation segment. In a base case this could be c. 140 million tonnes by 2050. In the bull case, 50% of the hydrogen demand comes from heavy trucking. In the base case, even 60%. But as mentioned before, improved batteries increases the competition between BEV and FCEV trucks, where BEV travel ranges are increasing and TCO are lower for BEV trucks, but where FCEVs will continue to benefit from lower weight and faster refueling times. Hence the ultimate demand for hydrogen in road transport is currently highly uncertain. Hydrogen demand in shipping by 2030 is expected to be neglectable but could become meaningful in the 2030s and 2040s. Aviation demand looks very similar to shipping with a later start but with higher demand levels by 2050 under all three scenarios.

Transportation and distribution costs for hydrogen are a function of the volume transported, the distance and the type of hydrogen carrier. For local distribution, pipelines can achieve low hydrogen transportation costs, particularly for retrofitted infrastructure utilizing existing assets, such as what state-owned Gasunie is doing in the Netherlands right now. Where such infrastructure is not available and where smaller volumes are required, trucks will be the solution for both hydrogen in liquid and gaseous state. Hydrogen pipelines are notably cheaper compared to electricity transmission lines. For short-distance transmission the most economical solution for hydrogen is also retrofitted pipelines where those are available. Trucks transporting liquid hydrogen (ammonia) seems to be more compelling at larger distances, while the cost of trucking gaseous hydrogen increases notably with distance. As the transmission distances increases, the cost of transporting gaseous hydrogen through pipelines increases at a faster pace than shipping in a liquid state (green ammonia, methanol, LOHC). Levelized costs of transportation including conversion and reconversion is thus highly dependent on the preferred choice of transport mode (pipeline versus trucking versus shipping), distance and volume, and could range between \$ 0.1 and \$ 1.5/kg hydrogen for distances up to 500 km on land, and between \$ 1 and \$ 1.5/kg for green ammonia per ship. In gaseous state, levelized storage costs ranges between \$ 0.25 and \$ 1.5/kg. In liquid state, this ranges between \$ 2 and \$ 3/kg. Costs at the fuel station are currently c. \$ 4.5-5.5/kg. Of course, this will decrease with larger throughputs over time.

Finally, a potential addressable market for hydrogen could be grid blending and grid stabilization, congestion and reliability management. The latter will come from small-scale electrolyzes taking excess RES power at times over ample supply when the grids are constrained to transport all electricity to markets (Exhibit 55). Decentralized grid-serving electrolyzers improve the energy yield from wind and solar plants, make the energy system more resilient and save grid expansion and congestion costs. Electrolyzers with a peak output of up to five megawatts (MW) are particularly suitable for grid-serving operation. Alternative solutions are BESS batteries as described earlier in this report. In Germany, a couple of decentralized grid-serving electrolyzers are in operations. Given the strong government involvement in the utility space, it would be interesting to see how the "utility electrolyzer" and the "industry-electrolyzer" will interact and cause more or less volatility and competition in the market.

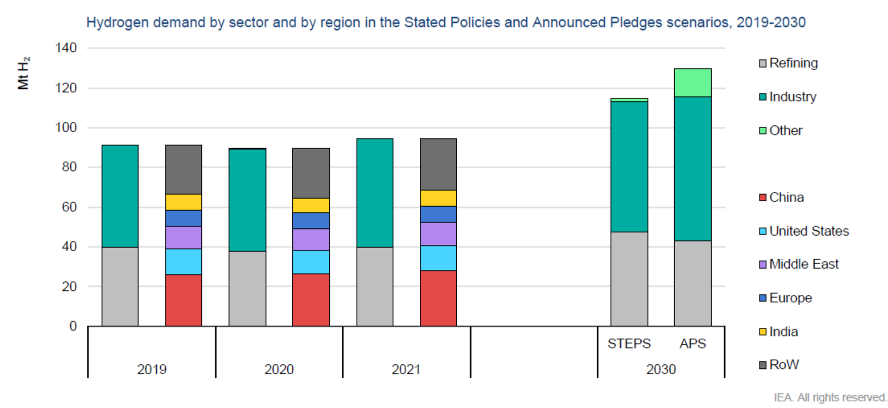
Exhibit 55: **Grid management solutions through small scale electrolyzers [39]**



Shell's latest energy security scenarios, published in March 2023, show a more sober demand scenario for hydrogen than others [40]. In its Sky 2050 scenario, hydrogen use begins to gain a foothold in the mid-2020s. In its Archipelagos scenario this doesn't happen until the early 2030s. In its first scenario, electrolysis will become the dominant methodology to produce clean hydrogen. Between 2030 and 2050 clean hydrogen will grow from c. 10 million tonnes to 230 million tonnes. In the second scenario CCS plays a pivotal role, but total clean hydrogen production stays low, at c. 60 million tonnes by 2050. The Sky 2050 scenario assumes that road freight transition also includes a shift towards electricity. This starts with light vans, municipality trucks and service vehicles, before spreading into medium-haul trucks. But for the very heavy-duty applications and long-haul, high capacity road freight, hydrogen fuel cell vehicles (HFEV) will emerge as the preferred solution. However, with the stronger than expected batteries now coming on the market, competition could start in the long-haul part of this transport segment. Shipping will also start experimenting with clean hydrogen carriers in the mid-2020s, with the expectation that the industry settles firmly on hydrogen-based solutions in the 2030s.

The IEA presented in her most recent global hydrogen review (September 2022) her demand outlook [36]. In 2030 they forecast a global hydrogen demand between c. 115 and 130 million tonnes (Exhibit 56). The high case is further split out in different categories for the world and for Europe in exhibit 57. Expected clean hydrogen demand in Europe is c. 14.5 million tonnes by 2030. This is c. 6 million tonnes higher than current demand. In this high case scenario, there is no decrease of grey hydrogen production, which thus assumes that there will be no substitution of grey into green hydrogen in the refining and industrial sectors. Instead it assumes that growth in demand will in all sectors be supplied by clean hydrogen. We believe that there will be more focus on substitution this decade than assumed in this outlook, also driven by court decisions and shareholder demands.

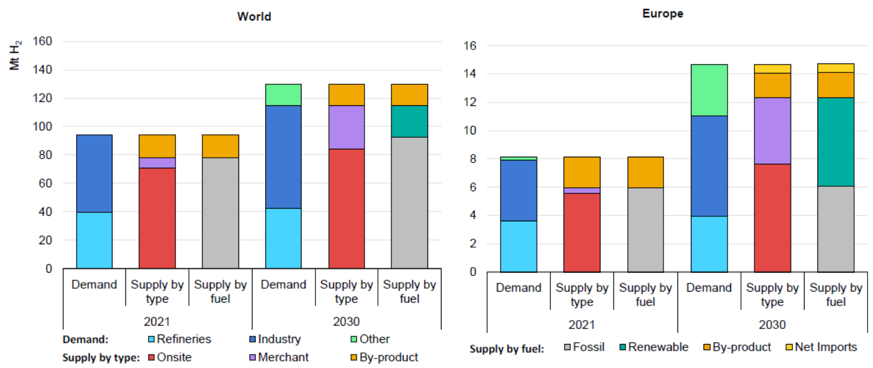
Exhibit 56: **Global hydrogen demand under two scenarios in 2030** [36]



Notes: Mt H_2 = million tonnes of hydrogen; STEPS = Stated Policies Scenario; APS = Announced Pledges Scenario. *Other* includes transport, buildings, power generation sectors and production of hydrogen-derived fuels and hydrogen blending.

Exhibit 56: Global hydrogen demand under two scenarios in 2030 [36]

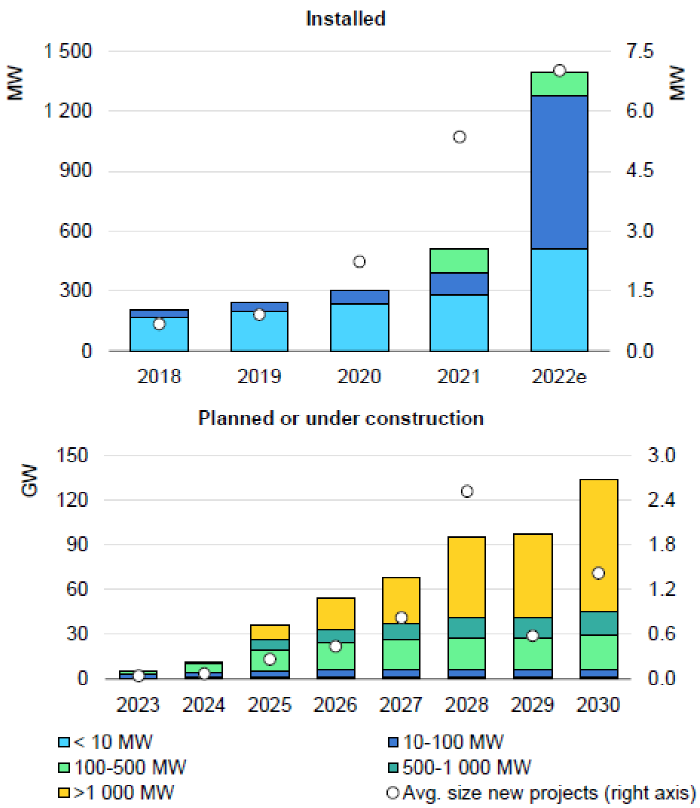
Global and European hydrogen demand by sector, and hydrogen supply by type and fuel in the Announced Pledges Scenario, 2021-2030



Notes: Other includes the transport, power generation and buildings sectors, and synthetic fuels. Europe includes the European Union, Albania, Belarus, Bosnia and Herzegovina, North Macedonia, Gibraltar, Iceland, Israel, Kosovo, Montenegro, Norway, Serbia, Switzerland, Republic of Moldova, Republic of Türkiye, Ukraine and United Kingdom.

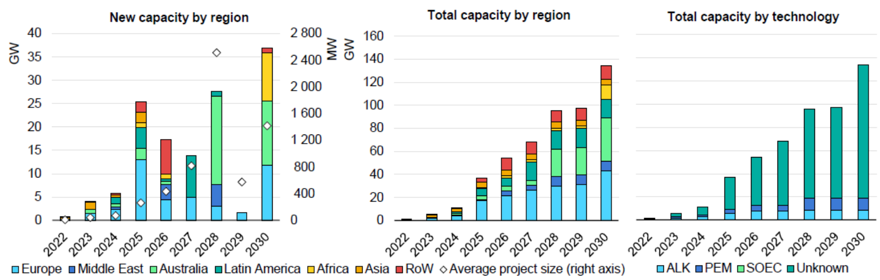
The IEA notes that global electrolyzer capacity could exceed 35 GW by the mid-2020s and reach 134 GW by 2030 based on the current project pipeline (exhibits 57 and 58). By the end-2021, the estimated installed capacity was 510 MW. This implies a 68X increase by the mid-2020s and 263x by 2030. The 134 GW in 2030 is a significant increase over the 54 GW expected for 2030 on the basis of the project pipeline in the 2021 edition of the Global Hydrogen Review (see also further below). At the time of publishing last year, only 175 of the 460 announced projects were under construction or had reached FID, accounting for c. 9.5 GW, while the others were at a less advanced stage. This corresponds with the current situation in the Netherlands, as described earlier in this report.

Exhibit 56: **IEA global electolyzer capacity by size based on project pipeline, 2018-2030** [36]



Notes: e = estimated. Only projects with a disclosed start year for operation are included. Projects at very early stages of development, such as those in which only a co-operation agreement among stakeholders has been announced, are not included.
Source: IEA, Hydrogen Projects Database (2022).

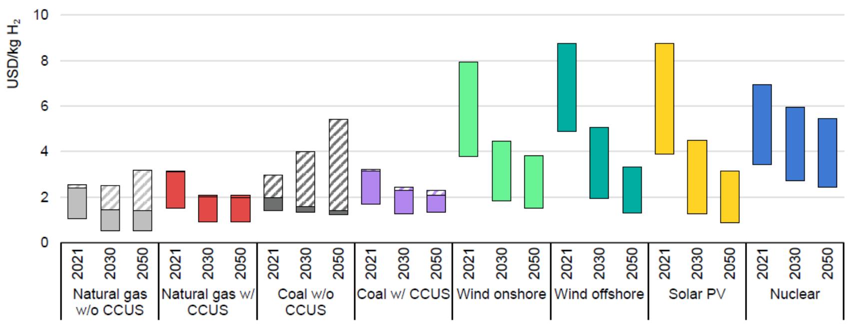
Exhibit 56: IEA Electrolyzer capacity by region and type based on project pipeline to 2030 [36]



Notes: RoW = rest of world; ALK = alkaline electrolyser; PEM = proton exchange membrane electrolyser; SOEC = solid oxide electrolyser. Only projects with a disclosed start year for operation are included. Projects at very early stages of development, such as those in which only a co-operation agreement among stakeholders has been announced, are not included
Source: IEA Hydrogen Projects Database (2022).

In 2021, in most regions the cost of clean hydrogen production was more expensive than the fossil fuels without CCUS route (Exhibit 57). The average cost comparisons were: $ 1.0-2.5/kg H2 from unabated natural gas; $ 1.5-3.0/kg H2 from natural gas with CCUS; and $ 4.0-9.0/kg H2 for production via electrolysis with renewable electricity. At prices of $ 25-45/ MBtu observed in June 2022 in gas markets in Europe, hydrogen production costs from unabated natural gas at $ 4.8-7.8/kg H2 are up to three-times the levels in 2021. Costs for hydrogen from natural gas with CCUS are in the range of $ 5.3-8.6/kg H2, of which $ 4.1-7.4/kg H2 alone is due to natural gas costs. With such prices, according the IEA, renewable hydrogen could become the cheapest option for producing hydrogen today in many regions if production capacity was available. Lower gas prices will increase the competitiveness of hydrogen production from natural gas again

Exhibit 57: IEA Levelized cost of hydrogen production per technology in 2021 and in the Net Zero Emissions by 2050 Scenario, 2030 and 2050 [36]



Notes: Ranges of production cost estimates reflect regional variations in costs and renewable resource conditions. The dashed areas reflect the CO_2 price impact, based on CO_2 prices ranging from USD 15/tonne CO_2 to USD 140/tonne CO_2 between regions in 2030 and USD 55/ tonne CO_2 to USD 250/ tonne CO_2 in 2050.
Sources: Based on data from McKinsey & Company and the Hydrogen Council; Council; IRENA (2020); IEA GHG (2014); IEA GHG (2017); E4Tech (2015); Kawasaki Heavy Industries; Element Energy (2018).

Citi updated its green hydrogen forecast in May 2023 [41]. Large subsidies under the IRA and a relative straightforward framework compared to Europe have attracted many more project developers and manufacturers to announce new clean hydrogen projects in the U.S. This has led to a revised forecast for the U.S., with 45 GW of installed capacity expected by 2030 (from zero in 2022). In their bull case, this could increase to 90 GW corresponding to the U.S. meeting its target of producing 10 million tonnes of green hydrogen by 2030 and a bear case of 15 GW corresponding to a scenario where IRA's green hydrogen subsidies are rolled back. The subsidy of $ 3/kg of green hydrogen produced makes green hydrogen competitive with conventional production methods. Furthermore, the U.S.'s less bureaucratic approach relative to the EU is appealing to manufacturers and developers and will accelerate development. The impact of the subsidies are expected to lower the LCOH with c. $ 1.9/kg. The announced capacity of green hydrogen production by 2030 in the U.S. stands at 5 million tonnes, with most of this related to companies focused on the green hydrogen market. In the bull case, all of the existing hydrogen production will be replaced by green hydrogen by 2030 thanks to subsidy support, requiring 90 GW of green hydrogen capacity.

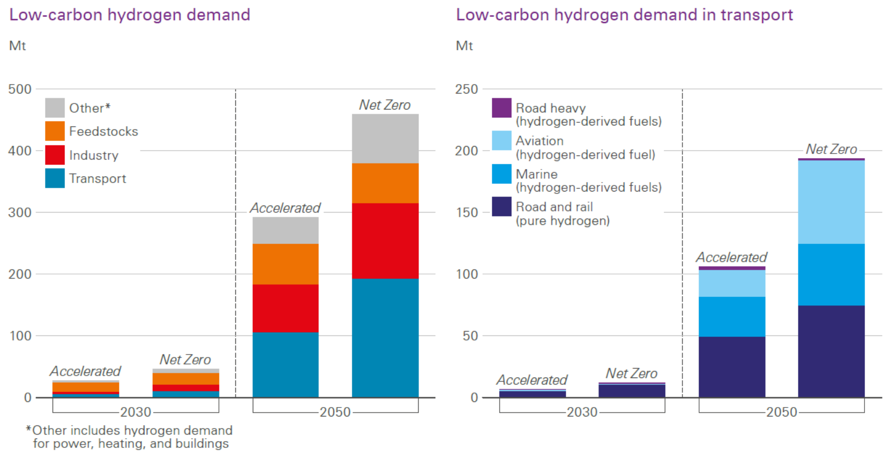
For Europe their base case forecast is 6.5 million tonnes of clean hydrogen production by 2030. Citi flagged the modest progress that has been made in creating the right political framework for the sector, identifying a gap between intentions and reality. They believe the EU's patchwork of policies at both federal and member-state level looks likely to persist, in contrast to the sweeping policies in the U.S. For instance, their calculations suggest that in order to subsidize all of the green hydrogen volume of its base case forecast (6.6 million tonnes per annum of green hydrogen production by 20230), the required budget would need to be Euro 260 billion, not Euro 800 million. As a result, they see the foundation of the Hydrogen Bank as a first step, establishing a mechanism for the development of the green hydrogen market. Citi sees thus the U.S. picking up fast and closing most of the gap with EU by 2030.

They also note that the Netherlands and Germany, the largest consumers of hydrogen in Europe, look likely to be among the biggest spenders of hydrogen. The Netherlands aim to reach 3-4 GW of hydrogen production capability in 2030 and become the world's largest importer of clean hydrogen through its ports including Rotterdam. Germany is currently updating its national hydrogen strategy. Their goal is high security of supply, highest possible share of domestic production and diversification and hedging of domestic imports [39]. There is a strong preference for green hydrogen, but blue hydrogen as a transitional solution is allowed. Although not formally yet announced, the following demand and expansion targets in 2030 are mentioned: 95-130 TWh of hydrogen demand, of which 40-75 TWh additional to today's demand, and national expansion target of 10 GW electrolysis capacity, of which 3.5 GW system-serving. In addition, the government will develop an import strategy.

BP presented in its Energy Outlook: 2023 edition its clean (low-carbon) hydrogen outlook [10]. According their outlook, the growth of low-carbon hydrogen during the first decade or so of the outlook is relatively slow, reflecting both the long-lead times to establish low-carbon hydrogen projects and the need for considerable policy support to incentivize its use in place of lower-cost alternatives. The demand for low-carbon hydrogen by 2030 is between 30-50 million tonnes in their two scenarios, the majority of which is used as a lower carbon alternative to the existing unbated gas- and coal-based hydrogen used as an industrial feedstock in refining and the production of ammonia and methanol – thus a focus on scope 1 and 2 GHG emission reduction.

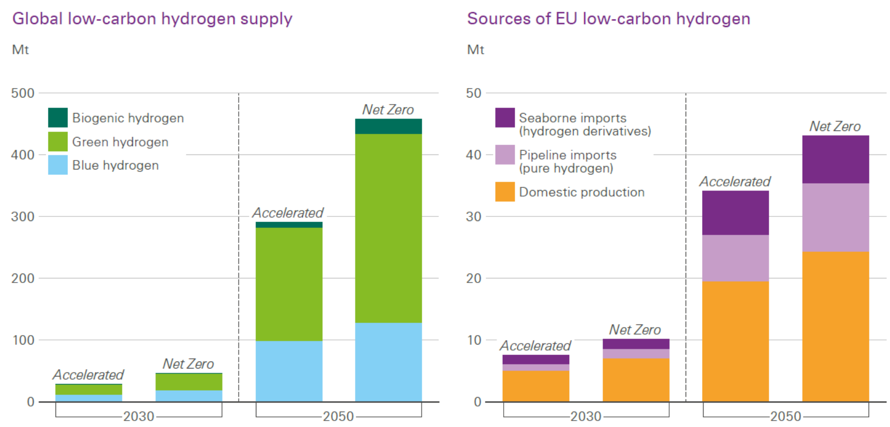
According BP, the pace of growth accelerates in the 2030s and 2040s as falling cost of production and tightening carbon emission policies allow low-carbon hydrogen to compete against incumbent fuels in hard-to-abate processes and activities, especially within industry and transport. Demand for clean hydrogen rises by a factor 10 between 2030 and 2050 in both scenarios, reaching close to 300 and 460 million tonnes respectively. In exhibit 58 the global clean hydrogen demand outlook is presented (left panel) and the demand in transport (right panel).

Exhibit 58: Low-carbon hydrogen demand [10]



In exhibit 59 the global clean hydrogen supply outlook is presented (left panel) and the sources of EU low-carbon hydrogen (right panel). For Europe they see sources of 8 to 10 million tonnes of clean hydrogen. This needs to be added to grey hydrogen demand in Europe, which is currently 8.7 million tonnes, and could be partly replaced by clean hydrogen. Also it expects that the EU will produce c. 70% of its clean hydrogen it uses in 2030, with that share falling to c. 605 by 2050. Of the clean hydrogen it imports, around half is transported as pure hydrogen via pipeline from North Africa and other European countries (Norway and the UK); the other half is imported by sea in the form of hydrogen derivatives from global markets.

Exhibit 59: Low-carbon hydrogen demand [10]



DNV presented in its hydrogen forecast the electrolyzer capacity by region in 2030, 2040, and 2050 (Exhibit 60) in June 2022 [42]. In Europe, they forecasted 111 GW of electrolyzer capacity in 2030, producing 6.6 million tonnes of clean hydrogen at the regional operating hours average of 3,000 hours/yr, falling short of the 10 million tonnes ambition by 2030 in its RePowerEU plan.

Exhibit 60: Electrolyzer capacity by region [42]

Units: GW

		2030	2040	2050
NAM	North America	10	120	305
LAM	Latin America	4	27	83
EUR	Europe	111	351	574
SSA	Sub-Saharan Africa	4	16	66
MEA	Middle East & North Africa	8	35	147
NEE	North East Eurasia	3	13	22
CHN	Greater China	258	899	1248
IND	Indian Subcontinent	18	80	263
SEA	South East Asia	3	27	123
OPA	OECD Pacific	45	180	244
World		**465**	**1748**	**3075**

They forecast production levels (all colors) of c. 17 million tonnes in Europe in 2030, of which 6.6 million tonnes green hydrogen (Exhibit 61). U.S. clean hydrogen production is still a meagre 1 million tonnes. However, this is still before the IRA was announced. In 2030, the largest green hydrogen producer is Greater China with 258 GW capacity installed and c. 11 million tonnes of green hydrogen production. Overall, they expect c. 25 million tonnes of green hydrogen in 2030 and 185 million tonnes by 2050. In addition, they expect c. 20 million tons blue hydrogen in 2030 and 90 million tonnes in 2050. Grey hydrogen production is in 2030 still as large as today, at c. 85 million tonnes, but by 2050 it has decreased to 50 million tonnes (exhibit 62). In aggregate, they forecast 130 million tonnes of hydrogen production globally in 2030, of which 45 million tonnes clean hydrogen.

Exhibit 61: Production of hydrogen by production route and region [42]

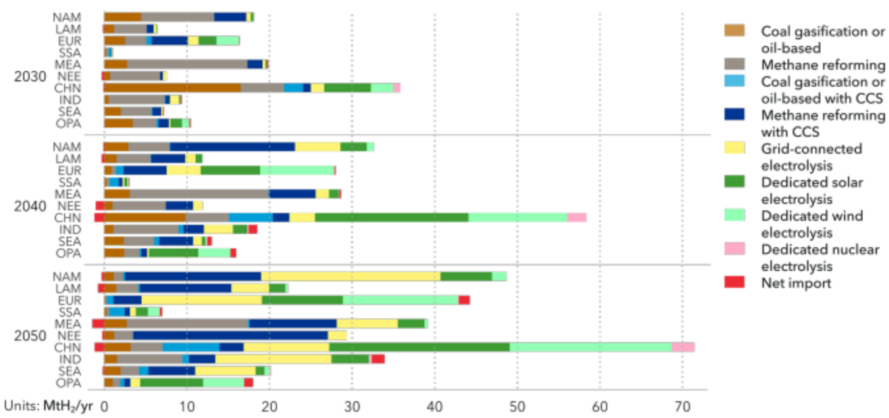
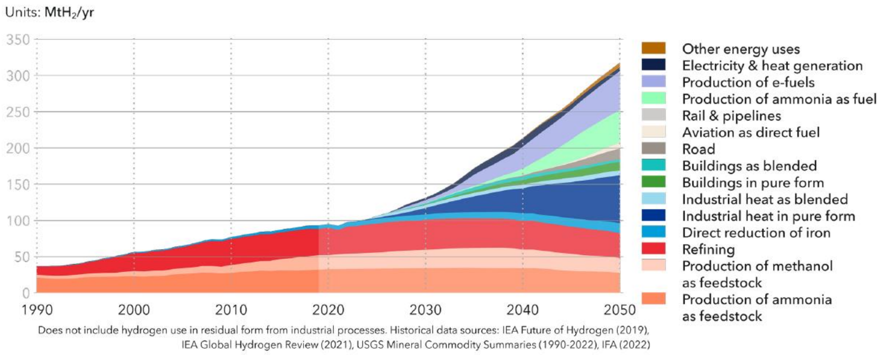


Exhibit 62: World hydrogen production by production route [42]

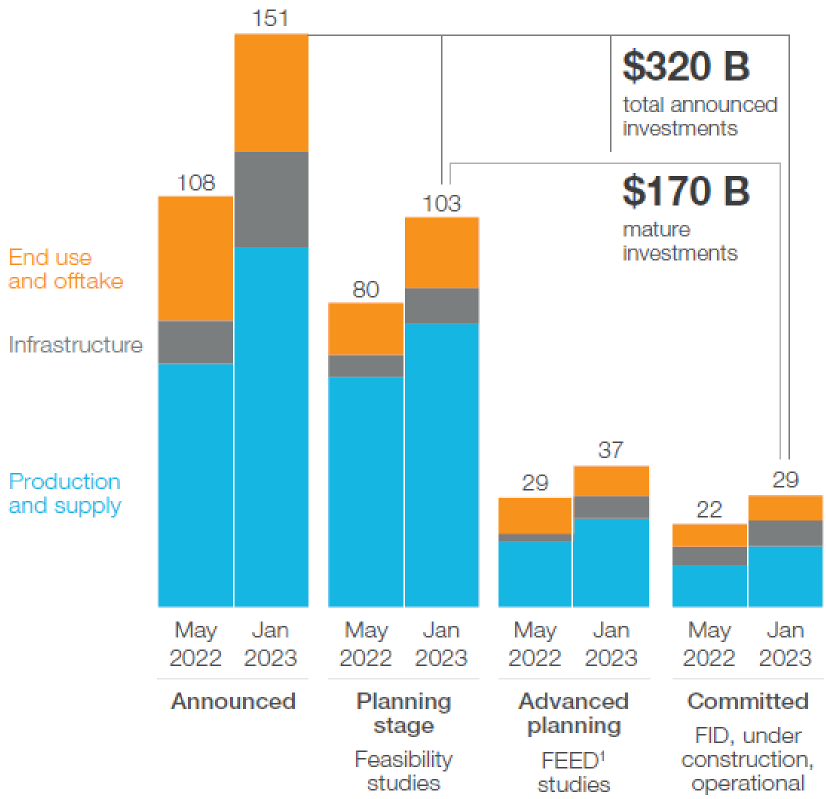


Finally, the Hydrogen Council / McKinsey & Company presented its hydrogen insights 2023 in May 2023 [43]. Globally, the industry has announced more than 1,000 large-scale project proposals as at the end of January 2023. Of the total, 795 aim to be fully or partially commissioned through 2030 and represent total investments of $ 320 billion of direct investments into hydrogen value chains through 2030.

Giga-scale project proposals (over 1 GW of electrolysis for renewable hydrogen supply or more than 200,000 kt p.a. of low-carbon hydrogen) account for 112 project proposals (requiring about $ 150 billion investment until 2030). Of these 112 proposals, 91 are renewable (green) and 21 are low-carbon (blue) hydrogen. In addition there are 553 large scale industrial projects, 191 projects in mobility, 94 integrated in the hydrogen economy, and 96 infrastructure projects.

Despite a positive trend, less than 10% of the $ 320 billion announced investments through 2030 are real committed capital (Exhibit 63). The industry is maturing in strained supply chains, including supply of electrolyzers, solar panels and wind turbines, slow permitting processes and unclear outcomes, labor shortage and EPC capacity constraints, increasing inflation and interest rates, complexity in deal making among parties along the value chain, price uncertainty (both of RES electricity purchase and hydrogen sales), and lack of public support in many markets, all of which may slow deployment. Closing the gap is challenging: by 2030, committed capital must increase more than twentyfold to track a net-zero scenario.

Exhibit 63: Direct hydrogen investments until 20230 in $ billion [43]

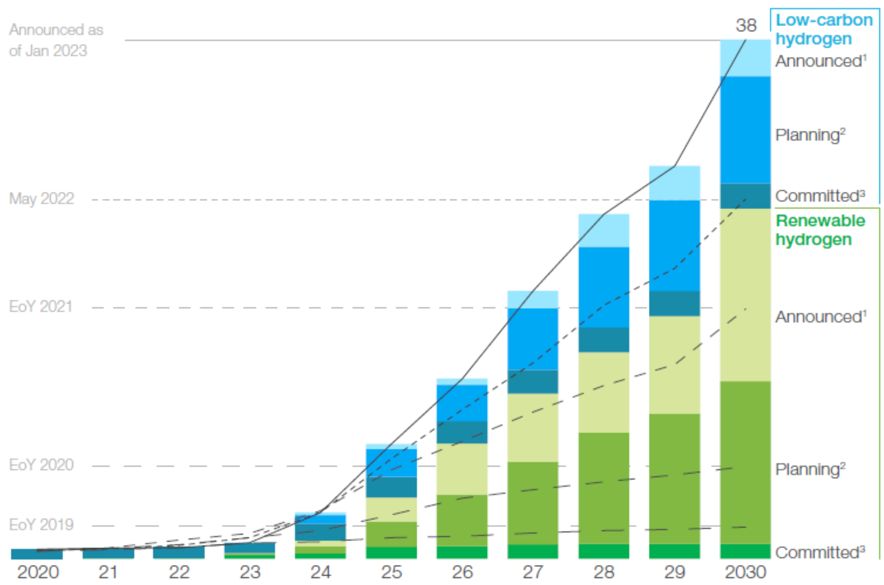


The average investment size of a project that has passed FID (280 projects) is about $ 100 million on average, whereas projects in the early stage (i.e., announced) require about $ 600 million investment on average. Besides the 280 projects on which FID has been taken, under construction, or operational, there are 83 projects in FEED studies, 172 in feasibility studies and 260 in preliminary studies or press announcement stage.

Companies have announced 38 million tonnes per annum clean hydrogen production plans globally for 2030, of which about half is in the planning stage or has committed capital

(Exhibit 64). More than two-thirds of the 38 million tonnes p.a. are renewable (green) hydrogen (about 25 million tonnes p.a.), and the remainder is low-carbon (blue; about 13 million tonnes p.a.). Today, 700 MW of electrolyzers are operational. This installed capacity equals c. 90 kt (0.09 million tonnes, or 1/277th of the 25 million tonnes p.a. announced) of green hydrogen. This is based on the assumption that the electrolyzer runs at 70% load factor and 67% efficiency.

Exhibit 64: Cumulative production capacity announced, million tonnes per annum [43]



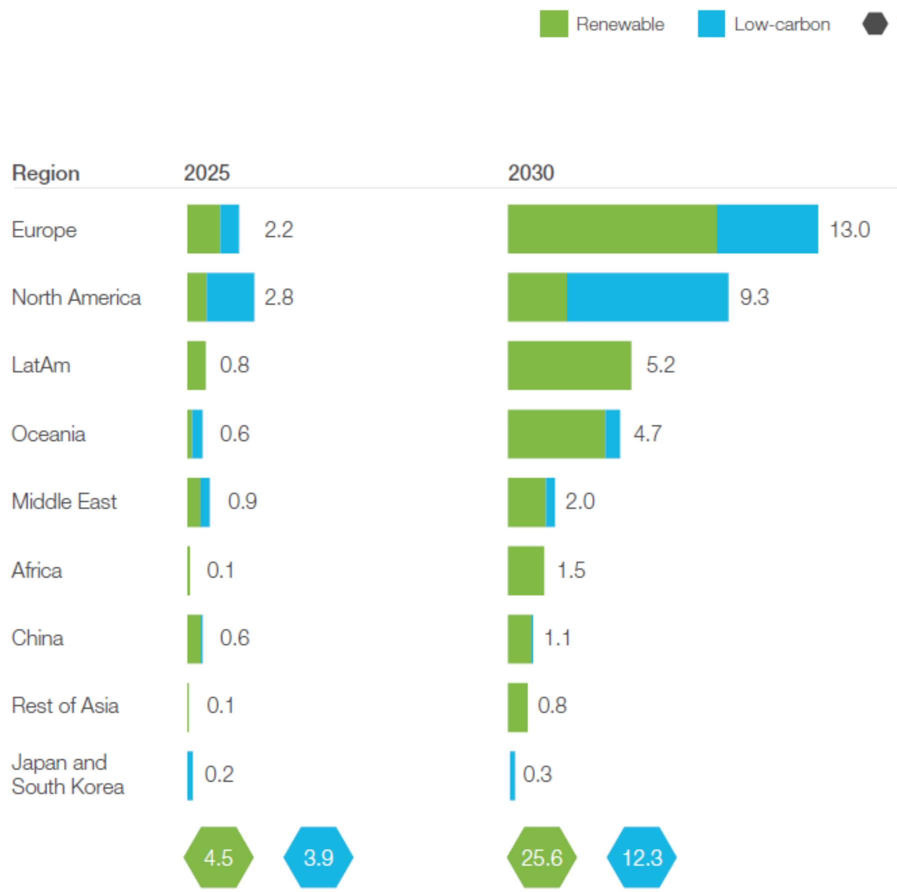
The next three to five years represent a significant scale-up challenge: nearly 3 million tonnes p.a. of capacity has passed FID (of which only 0.8 million tonnes p.a. is operational in addition to c. 2.1 million tonnes p.a. clean hydrogen under construction, of which c. 1.1 million tonnes p.a. is low-carbon (blue and 1 million tonnes p.a. is renewable (green) and should be deployed in the coming years. This is predominantly in North America (about 70% of volumes), followed by Asia-Pacific (about 15%, most of which is in China) and the Middle

East (8%). In 2030, 38 million tonnes p.a. is roughly half what is needed to be on track to a net-zero scenario (75 million tonnes p.a. in 2030) [43].

Despite Europe's clear position as leading on announced volumes, this is not reflected in the maturity of the project funnel, of which only 5% are committed volumes. Other regions have a significantly higher share of mature volumes. Of the total announced supply in China, about 40% is committed, while in North America, the share is 20%. The low announced volumes in China particularly could be due to fewer companies announcing their plans or different public support schemes.

In North America, more than 70% of the capacity announced is low-carbon (blue) hydrogen, which, in many cases, is lower cost for the end user. Developers in the U.S. have received tax credits to capture and store CO2 (45Q credit in place before the IRA). Further, low-carbon hydrogen is less capital intense at about $ 2.5 to $ 3.5 billion per million tonnes capacity versus $ 4.5 to $ 7 billion per million tonnes capacity for renewable hydrogen. This could explain the higher maturity of the project pipeline in North America. Exhibit 65 presents the clean hydrogen volumes announced. The chart makes it clear that before 2025 most work in in the pre-construction / pre-FID phase (as was the case in oil and gas between 2000 and 2004 as earlier described in this report). This must result in high construction activity between 2025 and 2030 in order to mature the announced projects and to get them operational.

Exhibit 65: Clean hydrogen volumes announced, million tonnes per annum [43]



It is important to note that millions of tonnes of hydrogen production is highly sensitive to the input parameters assumed, not only from a maturity of development point of view but also on chosen load factors.

As mentioned before, according the Hydrogen Council, companies have announced c. 25 million tonnes per annum green hydrogen production plans globally for 2030. More than 230 GW of electrolysis capacity has been announced through 2030, including 80 GW in Europe (of which c. 32 GW in the planning stage or beyond). More than half of this capacity (c. 120

GW) is considered mature. (i.e. undergoing feasibility or FEED studies (nearly 111 GW) or has passed FID (c. 9 GW). Of the 9 GW that have passed FID, 5 GW is in China and 1.35 GW each in the U.S. and Europe. This compares with 700 MW of electrolyzers (0.7 GW) currently deployed (producing 0.09 million tonnes of green hydrogen). Of the 700 MW of installed electrolyzers, c. 300 MW is located in China, followed by Europe (c. 180 MW).

5. Chapter 5

5.1 Hydrogen price formation

A commodity is a product that it is indistinguishable from any other product of the same type in the eyes of the purchaser, regardless of its origin. This frequently applies to raw materials such as (non) ferrous metals, oil and natural gas, and agricultural products. However, transformed raw materials and manufactured products, including hydrogen and ammonia, can also be classified a commodity under certain conditions. The distinguishing feature of a commodity is that it is a good with a standard quality whose product characteristics are, in principle, verifiable before purchase. Information on the product characteristics – including production, storage, transport, and substitutability factors – is available at low cost to prospective purchasers of a commodified good. This entails that the demand for commodities is intrinsically sensitive to price fluctuations. Actors looking to purchase a commodity can 'shop around' [44]. In effect, unlike with differentiated products, commodity prices are based on the supply and demand function of the market, rather than the properties of the individual product. The reducibility of commodities to relatively homogenous products means that product characteristics do not generally translate to competitive advantages or disadvantages to businesses trading in the good. Standardization of a commodity lends itself to relatively high substitutability, and hence price generally becomes the main determinant for transactions to take place. Price itself is influenced by a variety of factors, which have lent commodity prices a high degree of volatility. This means price discovery and setting functions are key to the formation and operation of a commodity market. Of course, scarcity, by nature or man-made will have its impact on the price of the commodity. Geo-politics play a large role in the price formation process. Equally, geo-finance plays a role, including the U.S. dollar Fx rate, economic growth and forecasts, and positions traders, market makers, speculators, commodity producers, and commodity buyers take on the commodity exchanges. It is the interaction between supply-demand fundamentals, geo-politics, and geo-finance that drives the price of the commodity. Moreover, commodities are inherently physical, not financial. Commodity futures are not the same as equities or bonds. Commodities are spot assets, that are largely a function of prompt balances versus equities and fixed income that are discounted future cash flows. Equities are a “share of” a company, granting rights to future profits (via dividends) as well as rights to vote on the direction of the company. On bonds you earn interest. Commodities are futures contracts, specified for a particular physical good on a specific month. Commodities price what is happening today, not tomorrow, and has no strong expectation value somewhere in the future. Furthermore, commodity futures obligate the holder to take physical delivery, if held to expiry (for which the taker has to arrange storage for which he/she has to pay a service fee). Most importantly, commodities are spot assets (i.e. a spot asset class) , reflecting today’s level of supply and demand and the actual mismatch between both at a single day, and thus driven by demand levels relative to supply levels. Hence this is the reason that ’the world’ is constantly predicting levels of inventories on a daily basis, and to test those forecasts with actual quoted stock inventories, where the price of a commodity goes up when actual commercial inventories turn to be lower than forecasted, and vice versa. Similarly, we now count hours of wind and solar much more precisely, per the hour, the day, the week and seasonally. In that respect you can remain bullish commodities as long as demand levels are still above supply levels (or expected to be so in the foreseeable future). Because of being a spot assets, commodities do not depend on forward growth rates but on the level of demand relative to the level of supply today and the levels of commercial inventories, and in the case of oil, strategic reserves levels and OPEC+ voluntary closed-in production levels – i.e. spare capacity – that can be brought back to market instantly. In that respect, the market functioned perfectly well since Russia invaded Ukraine, both during the initial period of sharply rising commodity prices and subsequently during the period of rapidly lower prices when inventories gave comfort that there was adequate supply to meet demand. Thus while forward-looking risk assets (such as equities) can price the forward fundamentals, spot assets such as oil and gas remain largely driven by current realities. The same counts for coal, electricity and hydrogen once the latter has developed itself as a true commodity.

In contrast to commodities that are a spot asset class, bonds and equities are anticipatory assets and are driven by the growth rate of demand, real and perceived risk profiles and communicated future interest or dividend streams.

Fundamental to the functioning of commodity markets is price discovery. Price formation of a commodity is influenced by the key drivers presented in exhibit 66 and the frequency and volume of individual transactions in that commodity, generally at a commodity exchange – a pricing center. In general, more buyers and sellers for a particular product leads to more transactions, which in turn leads to more liquidity in the market and a narrower the bid-ask spread, which therefore arguably leads to a better price discovery mechanism in the market.

Exhibit 66: Key drivers of commodity price formation [44]

Product Characteristics	Supply Factors
Quality	Product convertibility and capital intensity
Storability	Horizontal and vertical integration
Renewability	Storability and transportability
Recyclability	Industry concentration
Substitutability	Geographical concentration (emerging markets)
(Final) usability	Technological developments
	Supply peaks and future trends
Demand Factors	**Exogenous Factors**
Income growth and urbanisation	'Financialization process' and monetary policies
Technological developments and alternative uses	Subsidies programmes
Long-term habits and demographics	General government intervention (e.g. export bans)
Economic cycle	The economic cycle and other macroeconomic events
	Technological developments
	Unpredictable events (e.g. weather)
Demand Factors Exogenous Factors	
Micro-structural developments (e.g. competitive setting)	
Functioning of internationally recognised benchmark futures or physical prices	
International trade	
Expansion of commodities futures markets and 'non-commercial' investors	
Futures markets infrastructure	

In commodity trading there are two different market types [44]:

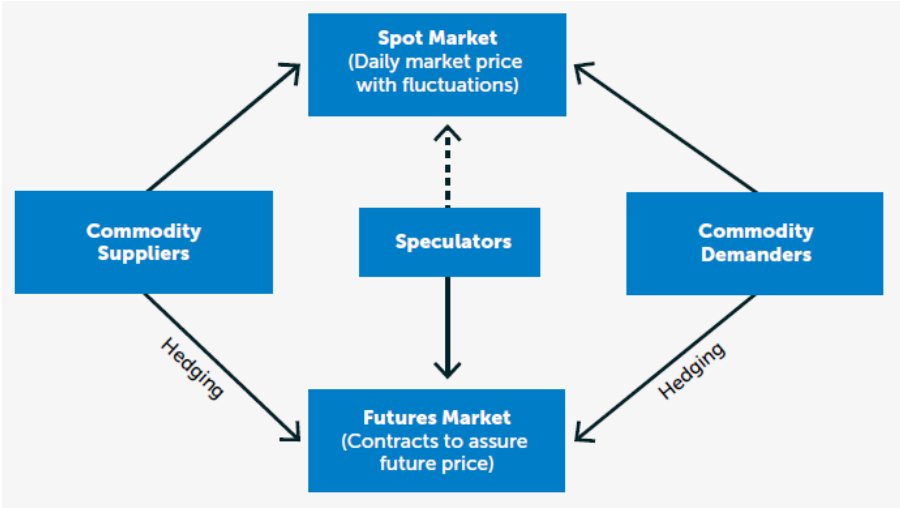
1) **Spot or 'cash' markets** consist of over-the-counter, bilateral, day-to-day transactions between buyers and suppliers (either directly or sometimes through commodity exchanges) and in which the physical commodities change ownership immediately with undisclosed prices and customized contracts. Since a physical exchange takes place (which can be coordinated from a distance), these spot markets tend to locate near ample supply and demand locations, with optionality for transformations in time, space, and form. As is often the case, spot markets may be located at large port-industrial clusters where the conditions of ample supply, concentrated demand, and sufficient optionality for transformations are met. Examples include the ARA, New

York Harbor or the U.S. Gulf Coast for oil products (gasoline, LPG, kerosene, naphtha)

2) **The futures market** is the trade in future delivery contracts with standardized dates, volumes and delivery locations on exchanges. It is mainly used to hedge against or mitigate price risks (by commodity merchants, large suppliers, and off-takers) and to speculate on price fluctuations (by investment banks, investments funds, private equity). It is a centralized market in which the exchange is the counterparty for both buyer and seller, and transactions are centrally cleared by the exchange or by a certified clearing house.

This is schematically presented in the following exhibit [44]:

Exhibit 67: Relationship between spot and futures markets for the trade of commodities [44]



Both markets strive to address and accommodate demand and supply disequilibria by way of providing a market clearing price at all times, for all traded quantities, and within reasonable time frames. To that end, it is necessary that both of these markets are competitive and aim to achieve high liquidity.

Being a spot asset class leads to distinct properties for commodities:

Commodities are physical, not financial assets: Chemistry ultimately dominates the physical market. Futures contracts are written for specific amounts of commodities (e.g. 1,000 barrels of West Texas Intermediate (WTI) crude oil), at specific quality grades, delivered to specific places (e.g. Cushing, Oklahoma, USA) in a specific time window. Each commodity has its own unique technology and supply-demand dynamics – including GHG emissions. Investors cannot treat an investment in one commodity as interchangeable with any other in physical terms.

Commodities are fungible: While there are different grades of each commodity, exchanges are set up to maximize the fungibility of the commodities in storage, allowing end buyers to receive a consistent product. Minimum quality requirements are required to write contracts on the commodity, and once on exchange, an order can be filled with stock from any combination of producers. Investors therefore do not know exactly who they are giving risk capital to, creating a "lemons" problem.

Investors transfer risk: The reason why commodity markets were established was to allow physical producers & wholesale consumers to move spot market price risk (e.g. a bad harvest) off their balance sheet. Producers want to sell their future production, and consumers want to buy contracts over the short to medium term (usually up to 6 months), in both cases to reduce operational and balance sheet risk. This time mismatch is covered by investors, who in turn receive both a passive stream of income for this service (roll yield) as well as exposure to long-term price trends (which can help hedge risks elsewhere in their portfolios.) Investors therefore do not get a direct vote in how each commodity is produced or consumed – rather they must indirectly express their preferences through liquidity / risk-capital allocation. With the arrival of oil in the 1860s, this agriculture dominated futures market was expanded with oil futures in West Virginia, USA, followed by New York, and much later with natural gas futures and the establishment of many more commodity price centers around the world.

Commodities form a complex web of inputs and outputs, making emissions hard to track: While companies are ramping up their ESG disclosure efforts, it is not always simple to track emissions accurately at the aggregate commodity level. Outputs from one market are often inputs into another (e.g. crude oil and oil products, grain and livestock), and co-production (multiple products being simultaneously produced from the same resource) is common for both metals and shale oil / natural gas. Investors therefore should pay close attention to exactly how greenhouse gas emission calculations are conducted. This is even more complex for clean energy sources, especially for those that are comingled or traded simultaneously with grey energy resources in such way that it is difficult to determine the origin for each electron or molecule. To solve this issue, governments, including the European Commission but also the individual member states and institutions working on certificates of the various products, the so-called Guarantee of Origin certificates and Renewable Fuel Units in the Netherlands and the Low Carbon H2 certificates at the EU level. Consistency and transparency in the setup is key to avoid fragmented markets with poorly designed products.

Commodities are interest rate sensitive: A rapid rise in the cost of capital lowers the incentive to hold either physical inventories or paper risk, distorting price discovery as financial markets generally respond faster than the real economy, and thus foster price movements.

Commodity prices, unlike financial markets, perform an economic function of balancing supply with demand: Prices will continue to rise to rebalance the market in the short term (i.e. to curtail economic demand growth while stimulating investments in future supply expansion), until the high price is no longer needed, and the price comes (crashing) down as demand destruction occurs and growth slows. If there is ample supply and commodities are in the exploitation phase where there are plenty of (commercial) reserves available to meet (expected) long-term demand and no large investments in new future supply are required, prices tend to stay low and trend towards the marginal cost of supply – today being U.S. oil and gas shale. Such phase normally takes 10+ years. However, geological decline rates – the reduction in the annual rate of production of oil fields after the peak – imply that global supply would fall, in case of crude oil by around 5% each year in the absence of investment in existing or new projects. Thus at a certain moment, the period of ample reserves start to shrink and commodities come to the end of their exploitation phased and enter the investment phase. At times of accelerated economic growth, like in 2000 with the arrival of the BRIC countries, this could trigger commodity super cycles. Early in the 2000s, long-dated oil prices started to rise on rising supply-side uncertainty about costs, as the market shifted from the exploitation phase, with the depletion of excess capacity, to a new investment phase where oil and gas companies recycled their increased revenues from higher commodity prices into the construction of new projects to expand supply. Unfortunately, such CAPEX will at first only create cost inflation as it did 2004-2008 (and in the late 1970s during the earlier investment phase) given the extended period of underinvestment. And precisely because demand growth can slow as yet demand levels continue to rise, commodities can continue to appreciate in price – as it did in 2007 and ultimately crashed in 2008 during the GFC. While not necessarily consensus, supply – demand fundamentals could require, but not necessarily trigger, a new investment phase. This is highly dependent on the success of failure of the energy transition on a global scale and the strength of the investment phase in the RES and hydrogen markets (to fill the gap caused by underinvestment in the traditional oil and gas space.

Time lag between FID decision and COD (Commercial Operation Date): It takes years to debottleneck the economy to absorb new CAPEX whether green, blue or grey. Today, investors may require a premium in long-dated prices to compensate for the increased investment risk from high uncertainty about demand. A rise in long-dated prices on increased demand uncertainty would mirror the rise in long-dated prices on supply uncertainty in the 2000s bull market. Indeed, the large uncertainty about long-run demand incentivizes investors to delay investment, especially for long-cycle projects. The energy transition to cleaner energy and fuels exacerbate this and lowers management willingness to sign off projects and investors willingness to hold their equity in commodity futures. The related fear of "stranded assets" raises the real option value of waiting for clarity on demand and of delaying investment. Such underinvestment in production leads to a depletion of inventories, removing a key buffer against fundamental shocks in prices, raising price volatility and lowering the willingness or ability of investors to get exposure to commodity derivatives. In the meantime, projected investments in the production of clean energy and fuels must not derail or be confronted with delays as that would trigger deep stagflation. But without sufficient CAPEX to create spare supply capacity – in whatever commodity, fossil or RES – commodities will remain stuck in a state of long run shortages with higher and more volatile prices. This interexchange between fossil fuels and RES is important because it drives the appetite to invest in RES production and determine the (relative) profitability of each type of commodity resource.

Price connectiveness and inter-relationships: As described before, RES commodity prices are currently largely set by the price of natural gas (and LNG), coal and CO2. Ammonia prices follow natural gas prices and so does grey hydrogen today, and the shift to BEV cars is a function of oil product prices versus electricity prices (assuming the CAPEX investment price is subsidized to bring them in range). For the time being, we might not have entered a new Supercycle, but it is not years away. Commodity super cycles never move in a straight line, rather they are a sequence of price spikes. In 1999, "everybody" was convinced oil prices would stay low forever, dubbed the 10 dollar oil world. However, when the Economist was quoting this on the believe of BP and Shell that prices would indeed stay low for the foreseeable future, it was exactly at the time that the then running exploitation phase was coming to an end. But it took the industry at least 4 years to accept this phenomenon and to understand the investment phase has started and a new super cycle was ongoing. Again, this is highly likely to happen again once U.S. shale can't grow any longer which is expected to occur in the 2026 – 2028 time frame. By then we are not ready (yet) with our energy transition. On clean hydrogen, at best we are in the construction phased of many projects. On RES and more specifically on offshore wind, we have indeed increased annual additions to levels described before. Because we are now in an exciting race between a new investment phase and a compelling substitution phase, and it is highly uncertain which one is going to win, there is a strong need to come to grips and accept more is needed to avoid a starved energy transition. At best, we buy time characterized by low but stable economic growth for the rest of the decade so that annual energy demand growth stays within the lower bounds of the forecasts made for the years ahead.

The exploitation > investment cycle is summarized in the following exhibits 68 [45] and 69 [46]. As noted the race is on whether we will be able to break out this cycle and the substitution phase will win, or that the historic commodity cycle will continue for the time being and the substitution phase will only come after another (perhaps short and partly) investment phase instead of a relatively smooth transfer from the late stage exploitation phase we are currently in directly into a full substitution phase.

Exhibit 68: Ready for a supply-constrained oil world? [45]

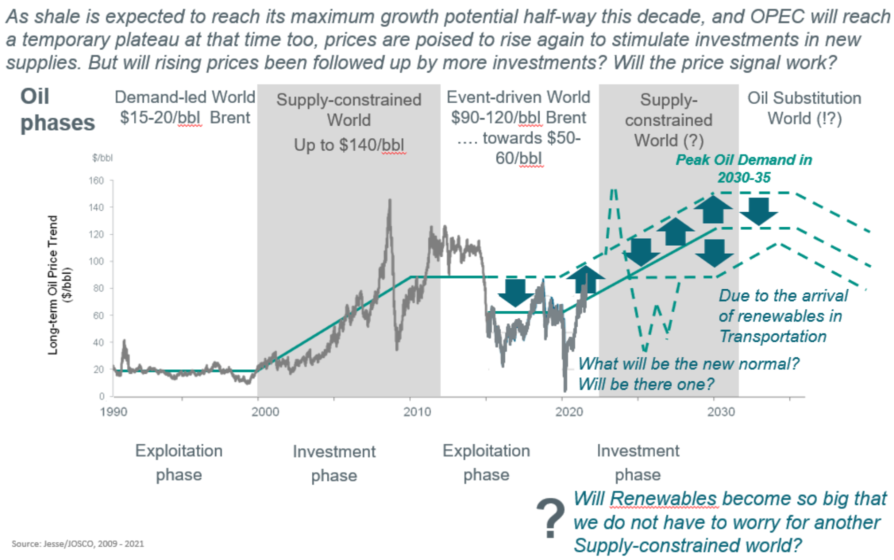
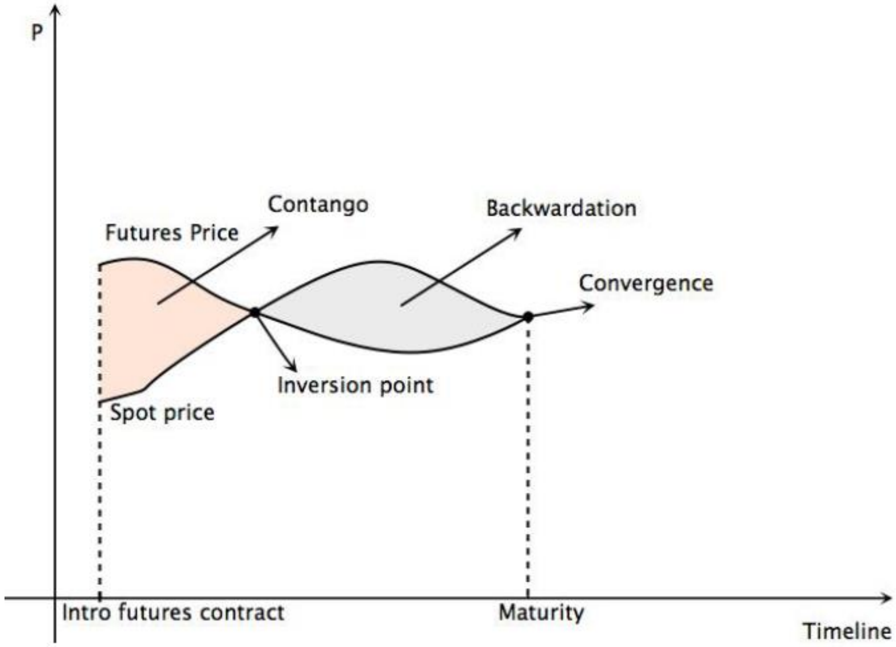


Exhibit 69: The commodity inflation – duration – investment cycle [46]

The most common type of market setting for the trading of commodity futures is an auction system handled by commodity futures exchanges. This auction system – nowadays through an electronic trading platform – is open to anyone who meets the financial requirements needed to trade these standardized contracts (among which is a margin call). The nature of an auction requires the market to be fully transparent with regards to membership rules, types of order that users can introduce into the system, and prices of each lot of underlying contracts. Auction markets, in addition, have lower transaction costs and can ensure a more efficient flow of information into prices. The interaction in price formation between futures and physical markets materializes in two phases: during the duration of the futures contract, and at maturity. During the duration of the futures contract, information about inventory levels and exogenous factors fuel increasing or decreasing divergence of futures prices with spot prices (Exhibit 70) [47].

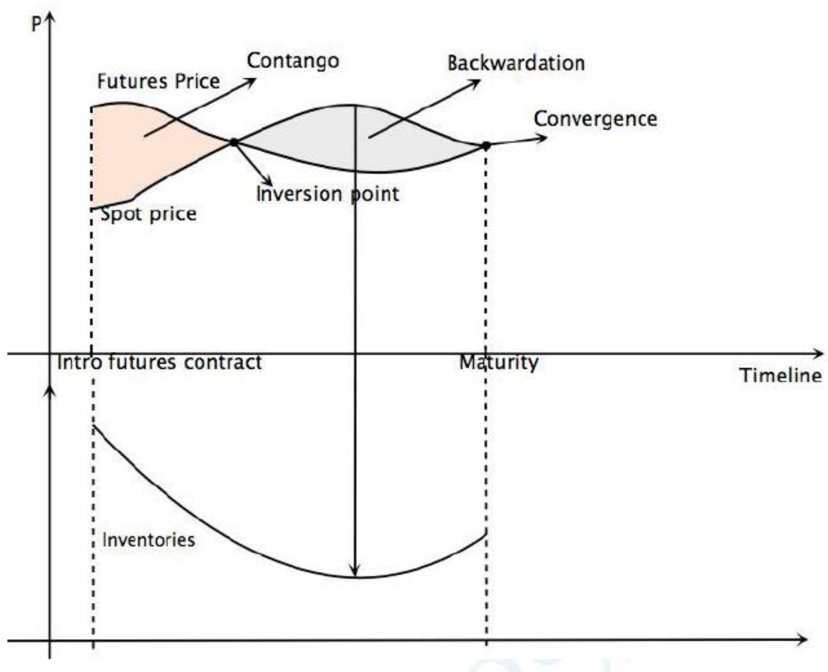
Exhibit 70: Futures and spot prices interaction [47]



When the futures price is above the spot price, i.e. the basis (difference between spot and futures price) is negative, the market is in 'contango'. When the futures contract price is below the spot price (i.e. the basis is positive), the market is in 'backwardation'. At maturity, the price of the futures should converge to the spot price due to the "commitment to deliver", which does not allow arbitrage to become systematic.

Both exogenous and endogenous factors (expectations) can affect inventories and, through them, the futures and spot price relationship. The relationship between storage and price is bidirectional. The level of storage sends important signals that influence price formation in both spot and futures markets. For instance, when situations of scarcity arise for a given commodity, reflected in low inventories, the spot price will tend to exceed futures prices and the spot price will show greater volatility than the futures price. The market is then in backwardation. In such situation of scarcity, i.e. when the basis is positive and thus when the spot price is higher than the futures price, the futures price is insufficient to cover interest foregone and the cost of warehousing (exogenous factors). Under such circumstances there is therefore an incentive to sell the storable commodity immediately, which results in a reduction in inventory levels. This will continue until spot prices are so high that demand falls and inventories recover and futures prices begin to regain ground to converge at maturity. Ample supply, as measured in part by inventories, will then generally depress the spot price in relation to the futures price and will subdue price volatility on both spot and futures markets. The following exhibit 71 illustrates the relationship between inventories and the marginal convenience yield, which ultimately affects the basis and so futures prices, creating a direct link between physical and futures markets.

Exhibit 71: Futures - spot price interaction through inventories [47]



European Hydrogen – whatever color - today is not (yet) a commodity. The pricing of hydrogen is regional and subject to requirement and volume in the industrial application. Many sources are captive. Much of the current production is co-located with demand. In the commodity sense, clean hydrogen is broadly uncompetitive. Therefore adoption will be a function of the industries that have customers who are willing to pay for a renewable claim. Alternatively there will be a structure of subsidies and taxes to ensure the adoption of hydrogen technologies. Expectations are that clean hydrogen will come down in price, and with reasonable learning rates this is probable. That said, this looks years away and so far markets are highly optimistic. Depending the clean hydrogen evolution in the coming decade clean hydrogen and its derivatives could potentially develop into a true commodity where price discovery and assessment takes place like in any other commodity. But such outcome is still uncertain and the journey towards such commodity market even more.

In that respect, one can learn a lot from the liberalization of power markets in the U.S. in the 2nd half of the 1990s, led by Enron at that time, and the natural gas markets, led by Shell. In 1998 for instance at Shell we developed Coral Energy as premier wholesale gas and electric marketer by establishing an asset based platform to become a leader in the deregulating North American natural gas and power market. However, today, we see the opposite occurring, a reregulation of energy markets. In how far this would enable and foster, or limit and constrain the development of clean hydrogen (and RES power) into true commodities is top of mind. In the late 1990s natural gas markets were liquid markets with established players, pricing points and basis relationships. There was an established forward curve and risk management was well established. In the U.S. power market, however, the market was very immature and highly regionalized. Electricity was thinly traded in most regions. And the regions were quite stand-alone with limited connection capacity. There were only a few established national players. The power market lacked transparent discovery and inter-regional price relationships. Regional forward curves were not well developed and hence price risk could not be sufficiently hedged. Risk management tools were limitedly available. The aim was to converge both markets by enabling the transition of the power and gas industries from district industries into a single dynamic Btu industry where perfect substitutability of electricity and gas for one another was not necessary for convergence to occur. It was absolutely clear that deregulation that had already started was the key driver in the process of convergence.

Like then, electricity markets in Europe are still highly regional and generation fuel mix differs sharply across the member states, characterized by significant difference in marginal production cost curves, low correlation between electricity prices among countries, while natural gas markets are less regional and regional price correlations are higher, especially all EU countries are now dependent on LNG imports. Also at that time there was low transfer capability between regions. Although this has strongly improved in the European electricity markets lately, in hydrogen we start from scratch.

Moreover, production of green hydrogen is based on renewables (still to be built) that are weather dependent (intermittent). This creates hourly, weekly, and seasonal volatility in the supply of green hydrogen. If the hydrogen is converted into e.g. green ammonia for export it will come per ship like LNG and needs to be stored in a receiving terminal (like FSRUs for LNG), who can then either sent a constant (24/7) green ammonia flow to customers, or first reconvert the green ammonia (liquid) back into green hydrogen (gaseous) before emptying its storage tanks on a 24/7 basis. However, when the green hydrogen is produced domestically, it comes in a gaseous state and can't be easily stored at site. Although studies are conducted to store clean hydrogen in caverns, generally the storage and buffering capacity will be much lower than currently is the case for oil and gas. In comparison with a natural gas network, the supply volatility of green hydrogen is likely much higher. Comingling green hydrogen with blue hydrogen could be a solution to produce more base load clean hydrogen.

In order to develop a liquid and transparent clean hydrogen market, you need the current major gas and power marketers to expand their trading and marketing capabilities at a certain moment in time into all kinds of colors of hydrogen and its derivatives. In the late 1990s it was seen that a successful Btu player would have a number of key characteristics [48]:

- A clear defined, focused strategy – something only a handful of EU Btu companies currently have with respect to RES and clean hydrogen trading and marketing.
- A "leveragable" physical asset base with access to physical commodity and low-cost generation plants in key regions, the control of, or access to, transportation assets in key producing / consuming areas, and to have (access to) flexible "in-the-market" storage.
- Financial strength and trading skills including physical and financial trading skills and risk management skills and systems, capital to support the trading business and access to "real-time" information.

- A customer-driven approach consisting of an established sales force and innovative services packages and marketing strategies
- Proved execution experience, especially of cross energy source / fuel, financially complex transactions.

Thus in order to create a good working clean hydrogen market supplied by domestically produced clean hydrogen from RES power and by clean hydrogen derivatives imports, there is a need for international and integrated players over the full spectrum of products: all type of RES power, all types of hydrogen, natural gas, and all types of credits and certificates. Those companies must be “leveraged” with dedicated assets to win a distinct edge over others and to build positions in the profit zones of the future energy value chains. At the same time assets along the value chain needs to stay unbundled. Also asset access provides better information about the commodity supply and delivery system, which is critical to the success of trading.

Different (future) customers in the new RES / clean hydrogen space can be identified. In the industrial space, one can classify two type of customers: **price buyers** who go after lowest cost energy and risk management execution. Those customers will always go for the cheapest energy resources that is legally allowed to “burn” or be cleaner as long as subsidies or credits make more expensive products within reach. In any case, they demand transaction cost leadership. Many of these customers in Europe are in basis industries who have to compete with others who have access to cheaper resources and/or based in countries with less restrictions (with respect to climate change objectives). It is questionable whether those price buyers have a future in Europe or that tax payers should do everything to keep them in. An example is Hoogovens, the Tata Steel company in the Netherlands and the largest emitter in the Netherlands, and whether they will adjust their production because clean hydrogen for their steel manufacturing processes is too expensive. Similarly, Yara, with a world-scale fertilizer plant in the Netherlands, has to compete against low cost producers, where analyses show that clean energy fueled fertilizer production is cheaper in for example Saudi Arabia than in the Netherlands. It can’t be excluded that those energy-intensive industries will “cash-cow” there existing installed base, and in the meantime take a wait and see position for as long as possible before deciding to make new massive CAPEX investments in Europe or ultimately to do them somewhere else (such as BASF has announced to do). Only the energy-intensive companies who have Europe as their captive market, have no good alternative option than to make the transition as quick as possible, with a strong focus on scope 1 and 2 emission reductions. Many of them will most likely fall in the second group of customers, the service buyers who want commoditized supply and transmission products and services, as well as risk management advice and execution. Generally, these companies are willing to pay premium prices for premium products, including uninterrupted (clean hydrogen) supplies and price (margin) certainty. They want price guarantees under different economic scenarios. This will require strong, sophisticated risk management capability by the seller. For the supplier, firm sales require some level of firm supply, all the way from the starting point of the value chain onwards. In this second category of service buyers are also the power producer utilities, who are pushed in the direction of system-serving electrolysis by governments.

Ultimately, in origination it is key to understand the customer with respect to his strategic drivers, resource constraints and risk profile and appetite, to understand value at risk (VAR), including the impact of all sources of risk and their impact on key value drivers and to track individual and portfolio positions in real time. This requires to have distinctive daily balancing skills, knowledge of network code, combined shipper / beach / flow balancing and monitoring capacity systems, access to storage, series of standard contracts and a wide network of industry contacts to become successful in building a top tier product aggregation and balancing, and trading and wholesaling platform. It is ultimately to the company to decide its degree of exposure (primarily hedged versus unhedged) versus scope of trading (internal system requirements and assets versus third-part deals and interdependency). The product and service mix is and will continue to change rapidly, which require continuously investment in new capabilities. PPAs are now the flavor of the day, being heavily promoted by the European Commission to reduce price volatility and to improve visibility. Recent communication by several industry players show that there is definitely scope to make improvements in this field, as many were overtaken by unexpected / unforeseen events that put their incumbent strategies at risk. Key is to know where you can make money as loss leaders are generally poor strategies.

Besides the wholesale and industrial customer base there are the retail marketeers and end-users. Those generally want bundled products and services, extremely firm delivered supply including volume variations for load swings and multiple pricing alternatives. The best examples are found in the retail markets in mobility and in the transport segment. Midstream, many parties might give preference for tolling agreements, delivering a service while not taking commodity price risk. But someone must take price risk. Especially in the early phase of clean hydrogen market development in the coming years when markets are non-existent or in an embryonic state, many will give preference to be in the back-to-back business through tolling agreements and classic SPA/PPA contracts, which spell out any possible trigger to a price change. Collars and indexed price formula's (such as in early LNG sales and purchase agreements where LNG prices where managed by so-called S-curves) are good examples to mitigate project specific commodity price risks. But even if as much as possible price risk, liquidity risk and correlation market risks are managed, due to the nature of the business, and especially in case of long-term SPAs/PPAs, there is a credit risk, and there are general business risks (operational, legal, regulatory) that remains and needs to be managed.

To be a trustable energy trader and marketer in clean hydrogen (and all the other energy and related products and services), from a corporate point of view, you need to have a strong balance sheet with access to capital, a strong brand name, scale, skills, scope, systems, reliability, dedicated supply, superior market insights, access to deal flow, superb valuation, and deal structuring capabilities to name a few. In the asset group you need (re-)regulated market expertise (different than in the late 1990s when you needed to have deregulated market expertise), valuation and deal making expertise, cost efficiencies and distinctive operational capabilities, merger and acquisition experience (for e.g. generation sales/aggregation and power procurement/aggregation) and technical and operational expertise. In the trading group you need fully-fledged marketing and fuel procurement skills, trading skills, market and price intelligence, forward price curve generation and ancillary services. Those could be industrial process energy optimization, different energy products and fuels supply portfolio management, financial risk portfolio management, hub services, transport and logistics asset management, facilities management and/or billing and accounting consolidation. Pending chosen strategy, traders, marketers and portfolio aggregators have different ways to participate; i) arbitrage and back-to-back trading; ii) position trading at liquid points; iii) multi-fuel relationships along geography, time and volatility; iv) asset backed trading; or v) financial only trading. Regarding financial products that could be offered, examples are fixed and option pricing for the various products including grey, blue and green hydrogen, sun and wind power together with nuclear and gas-fired power, weather hedging, cross commodity structured products, “import/domestic-buy-produce-sell” cross-market arbitrage pricing strategies, risk/return analysis and solutions, deal structuring and financial engineering, and foreign exchange and interest rate products.

Finally, spot prices represent credible and fair value for commodities (and becomes index). Long-dated prices give visibility and show transparency. Deviating away from these base characteristics of commodity markets limit the development of a market and create artificiality in the market and in its function of price discovery and price assessment process. The over-arching question is of course if the European Union and its member states actually want to see clean hydrogen to develop into a truly commodity and see the development of a distinctive group of traders and marketers with skills and capabilities as described hereabove. or whether they want to re-regulate RES power markets “away from a market dominated by traders in power commodities. Ultimately, there are five key factors affecting the new wholesale RES and clean hydrogen market place:

- Government de/re-regulation with open access to markets
- Sponsors ready to invest in physical assets along the value chain
- Willing buyers and sellers
- Building scale to achieve lower costs and liquidity
- Convergence of green electrons with green molecules and both with grey ones

Together, they will define the wholesale energy market evolution, and agree in how far the current model is under pressure and which, how, and when new emerging models will replace the incumbent model. Whatever is chosen, the successful market must meet the requirements regarding price discovery, price formation and price assessment and must allow participation options available for players in the market.

While there is no commodity market for hydrogen, many governments, institutions and companies are working on the commodification of hydrogen and ammonia as the most promising hydrogen derivative for large traded volumes. Three phases could be conceptually identified along which route this might happen over time. For both hydrogen and ammonia, the market today is small, not transparent, and comprises largely of captive production where current production is co-located with demand, and where this is not the case, it is arranged through bilateral long-term contracts. There is no international trade in hydrogen and only for a small percentage (roughly 10%) in ammonia. Through these long-term contracts between sellers and buyers a market equilibrium is reached. Spot trade can exist in this market, but it is negligible in volumes and activity. Interactions tend to be informal, highly specialized, and/or incidental. General terms and conditions are confidential. In (the later part of) this first phase, bilateral markets will eventually convert into market hubs with sufficient concentration of demand and supply where bilateral over-the-counter spot and forward contracts are struck between two parties, usually the producer and the end user. Contracts can have different tenors for immediate (spot) or long-terms deliveries. These bilateral contracts are highly customized and lack transferability. This exposes the parties to flat price and credit risk.

When volumes grow in volume and diversification of demand, and activity increases, generally participants start asking for more liquidity, transparency and visibility. This normally goes hand-in-hand with the development and the construction of infrastructure and other hardware for the commodity's supply, storage and transport to buyers and end-users of the commodity. More information about the commodity and the trade becomes available and information systems become more sophisticated. Generally, government and regulatory bodies become involved in the permitting of the construction and operations of the physical assets and the allowance of the commodity to make use of the transportation infrastructure. With this, a more regulatory environment develops in response to the diversification of demand.

The European Commission and some of its member states, notably Germany and the Netherlands as potential large clean hydrogen consumers, and Spain and Portugal as potential large clean hydrogen producers, do everything to make this first phase as short as possible and to stimulate investments that enable this accelerated growth towards the next phase. For instance in the Netherlands, the hydrogen backbone will be completed by 2030, linking the main ports with all major industrial clusters and beyond into Germany and Belgium. In parallel, the Netherlands will continue to award offshore wind licenses, which will feed the electrolyzers to be built. There is well organized and funded initiative to establish a new hydrogen exchange (HyXchange) in the Netherlands with Rotterdam as the pricing center for Europe. The Netherlands aim to reach 3-4 GW of hydrogen production capability in 2030 and become the world's largest importer of clean hydrogen through its ports including Rotterdam. In Germany a new hydrogen grand strategy will be published later this year. Their goal is high security of supply, highest possible share of domestic production and diversification and hedging of domestic imports [39]. There is a strong preference for green hydrogen, but blue hydrogen as a transitional solution is allowed. Although not formally yet announced, the following demand and expansion targets in 2030 are mentioned: 95-130 TWh of hydrogen demand, of which 40-75 TWh additional to today's demand, and national expansion target of 10 GW electrolysis capacity, of which 3.5 GW system-serving. In addition, the government will develop an import strategy.

Still, those government-led 2030 strategies are ambitious. To reach 3-4 GW of electrolyzers by 2030 in the Netherlands, industries have to develop 15 to 20 times the 200 MW Shell-size hydrogen factories in the coming 5 years and to have them built and up and running by 2030. Moreover the seven projects that already received Euro 800 million of subsidies (through the 2nd wave of EU IPCEI-hydrogen funds – Important Project of Common European Interest) for their green hydrogen plans in the Netherlands, only one (Shell) is under construction, and with an aggregate installed capacity of 1.150 MW, they collectively represent only 1/3rd to 1/4th of the target. Those corporations are all large industrial companies and front runners in hydrogen. Under the European IPCEI, Euro 1.6 billion has been allocated to the Netherlands to be payable in four waves (of which now half has been allocated to those seven project developments). If the costs per MW will be equal to Shell's plant, the total downstream electrolyzer costs would be c. Euro 15 to 20 billion. The allocated subsidies would most likely be too small to enable the sponsors to take FID on their projects.

In addition, some of those industries serve different segments in the transport sector. During this first phase, they plan to start selling clean hydrogen or hydrogen derivatives to this sector through their retail outlets and/or whole sale fuel marketing and logistics businesses. But for reasons mentioned earlier in this report, notably the fact that LCOEs and LCOHs are too high, the number of hydrogen customers in the mobility sector are still slim, and because of the many challenges project developers are confronted with, we believe that the 2030 targets are too ambitions and not realistic under current circumstances. We expect many years of delays and therefore a slower ramp up in production volumes and thus in trading hydrogen (derivatives).

Finally, you have the power production sector, been pushed in the direction of system-servicing electrolysis. These operations require flexible deployment of electrolysis primarily at times of low residual load and moderately low full-load hours. Green hydrogen production will only take place if RES power is available against low prices. Hence, supply is also variable, pending the capacity to store.

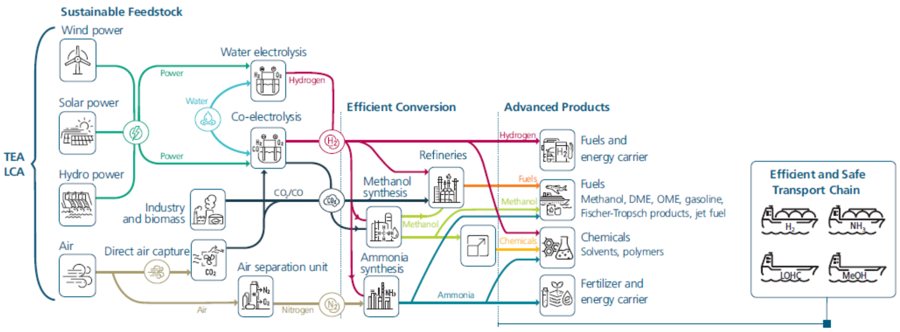
But at a certain moment, the hydrogen market will evolve towards phase 2. In this phase more new players will enter the market and demand will diversify. Production capacity will become more flexible. Assuming upstream infrastructure has expanded, and total CAPEX unit costs have improved materially, the volumes produced will gradually increase through efficiency gains and further investments to meet growing demand. The increased supply volumes allows producers to capture new markets and to sell excess production on the spot market. Hence, this phase will be dominated by more transparent spot market trading, which balances supply with demand, introduced customized forward contracts, and sets the benchmark for long-term contracts. This is a crucial step for building confidence for the use of the commodity in key parts of the energy system, as market players can access more and better information, leading to improved price discovery, and therefore further balancing of supply, demand, and price. Feedback loops will attract more market players – enabled by government policies and subsidies [44]. In turn, with a larger and more diversified demand for the commodity, the spot market is expected to grow materially. Over time, clients have a greater need to hedge their price risk. Also other type of risks arising out of larger trading volumes, such as flat price, basis, spread, margin, volume, liquidity and operational risks, will demand more sophisticated trading instruments, currently already in place for risk management of other key commodities. If trading houses have not entered in phase 1, they will do so in phase 2 as there is a growing role for trade and aggregation.

The question is whether hydrogen producers who will enter into long-term sales and purchase contracts with end consumers for selling clean hydrogen, will also enter back-to-back into long term PPAs with one renewable energy producer, or give preference to a utility who can provide electricity from a mix of sources, or combine this with spot power purchases. Ultimately, each player along the clean hydrogen value chains have to define their risk appetite and absorption capacity. Forward contracts, which are generally highly customized bilateral agreements, must help to hedge against price volatility on the spot markets and help manage open positions and speculative length.

The final phase 3 – still many years out - focuses on the growing role of the commodity exchange and the commodification of clean hydrogen and its derivatives through the standardization of forward contracts to ease liquidity. These standardized contracts, known as futures contracts, are more readily transferable. ICE – one of the two dominant exchange for commodities in the western hemisphere – must decide at a certain moment that the market has evolved and sophisticated enough that there is a need for the introduction of clean hydrogen futures and clean ammonia futures, should ammonia be chosen over competing carriers. In this phase, financialized instruments are introduced on the commodity exchanges. Such futures will become the benchmark for the markets its serve and play a key role in price discovery. Price formation emerges from interaction on both physical and futures markets, which feed back into the market as price signals. Price discovery will then take place at the exchange through the liquidity provided. It is particularly this liquidity that is the main factor in determining whether a market price (the benchmark) will become the reference point. Price transparency will be secured with the futures price converging to the spot price as contracts mature. New financially driven market makers will arrive in the market, as well financial institutional investors and hedge funds and other speculators. Those parties trading in futures do not have the intention of completing the underlying transaction of the physical good. In fact, a seller of the future contract may not be in possession of the physical good, and the buyer may not have the intention of receiving a physical delivery. This detachment from the physical good is, in essence, a reduced barrier to entry into the market, allowing actors across the world to trade in futures contracts on centralized futures exchanges – such as ICE. Futures markets generally enjoy higher liquidity with the growth of a large pool of new participants.

Development of new exchanges is not easy and takes years to become successful and accepted by market participants. Examples are abound in e.g. the oil market with a relatively new exchange in Shanghai, and the many regional power and gas exchanges in Europe. In that respect, there will be many possible pathways how we will arrive to phase 3 and how phase 3 will look like. Different than with crude and oil products, electricity, or natural gas and LNG, which are vertically organized, clean hydrogen is also horizontally organized through its pool of different clean energy suppliers, different end markets in the stationary and mobility sectors, both in wholesale and retail, and most importantly because of its derivatives where hydrogen will arrive in end markets in liquid state (ammonia, methanol, LOHC), while domestic production will be in gaseous state. The power to liquids process chain is complex and will have various specific elements that are only applicable to one particular product but less so for another. Exhibit 72 presents the power to liquids process chain [49].

Exhibit 72: Power to liquids process chain [49]

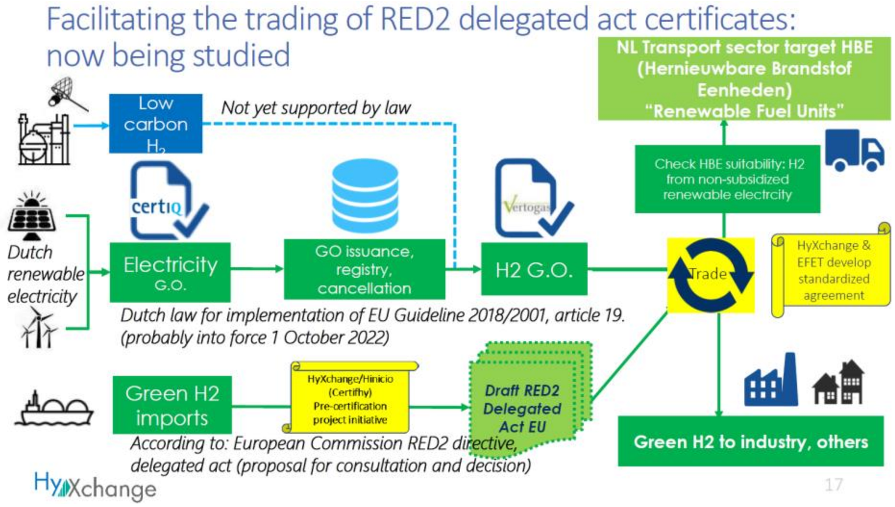


In Europe there is now a trend where governments want to intervene in power markets (through the proposed reconstruction of European power markets) and want to have a big say in the development of the futures hydrogen market and its exchanges. For instance, the HyXchange is an initiative of the Dutch government. In how far this would impact the development and the pace of the development of liquid clean hydrogen markets (and for its derivatives) is to be seen, especially if each country develops its own solution and causes fragmentation. This said, HyXchange is a very successful initiative: its overarching initiative is to establish a hydrogen exchange based on a (state-owned) Gasunie hydrogen backbone and with sufficient diversity of players. It recognizes the need of open access and network operations by an independent network operator (i.e. GTS, a Gasunie subsidiary acting as the national TSO), with a single access rate (postage stamp tariff). In addition there is a need for ancillary services, where market participants supply products to the network operator for the operation and quality assurance of the hydrogen network.

However, given the fact that the backbone will only arise over time, it is also considering launching an exchange in the start-up period at an already completed or existing physical point (or points) for hydrogen if there is sufficient market diversity. It is also conducting extensive studies and simulation activities that should lead to the trade in “Guarantees of

Origin" of green or decarbonized hydrogen between such locations, also in the period prior of the backbone. The HyXchange G.O. pilot was initiated in January 2022 in anticipation of the Dutch law on the implementation of Guarantees of Origin from renewable sources, including hydrogen [50/51]. A large group of 18 potential producers, traders and consumers are participating in this pilot, including Vitol, the Dutch largest company. It includes the facilitation of the trading of European RED2 delegated act certificates (exhibit 73). An important difference between commodity markets and the future hydrogen market is the expectation that a large part of the emerging hydrogen market will be driven by compliance targets. The compliance targets can either be mandatory, derived from EU or national member state policies, such as the EU Renewable Energy Directive (REDIII) and national environmental laws, or can be voluntary as set by companies' corporate social responsibility (CSR) strategies.

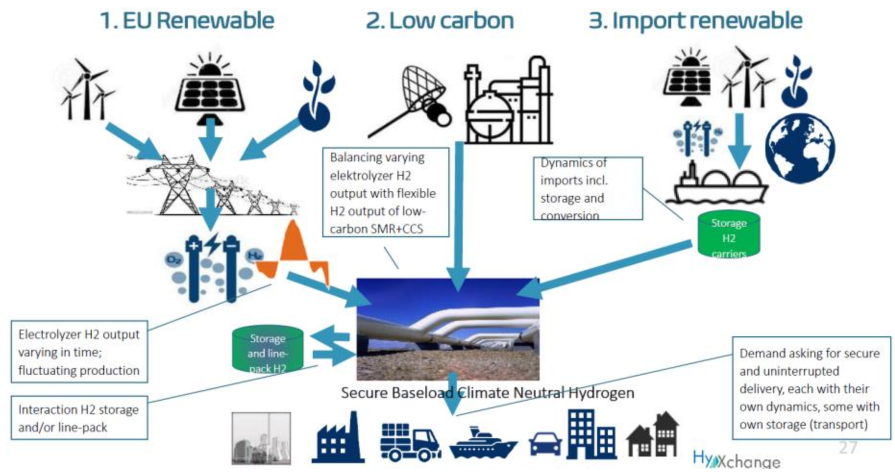
Exhibit 73: Certificates of Origin in Europe [51]



Companies are expected to pay premium prices for hydrogen that has the specific environmental attributes that allows them to meet their compliance targets. These hydrogen attributes could be a low greenhouse gas footprint, or production via renewable electricity. For the market to recognize and verify such environmental attributes, certification is a proven approach. Guarantees of Origin (G.O.) certificates allow markets to verify the production origin of the hydrogen. Thus through the purchase of Guarantees of Origin, companies can provide evidence that their hydrogen is produced from renewable sources and/or has a low carbon footprint. G.O.s can be traded freely, allowing the physical consumption of the renewable hydrogen to be administratively separated from the consumption of the actual molecule with its own physical supply chain.

Another focus area is the launch of a hydrogen price index based on a so-called “pricing panel” in which the various market participants are regularly consulted on the current trading price. However, there is a good chance that this will be taken over by S&P Global Platts and Argusmedia, the premier commodity price assessment institutions who are already doing so for grey hydrogen and for ammonia price assessment and market data information.
Since the 2nd half of 2022 is HyXchange conducting extensive spot market simulations on which it regularly communicates [51/52]. The simulation must give insights into likely development of a hydrogen spot market in Northwest Europe (with Rotterdam as pricing point), based on a variety of clean energy sources, load factors and demand patterns. The hydrogen spot market and balancing simulation is on a (inter) national hydrogen grid, which is unique in the world. The simulation balances varying electrolyzer hydrogen output with flexible blue hydrogen output of low carbon SMR+CCS. Hydrogen hourly electrolyzer overproduction is stored or utilized in gas fired power plants. Storage is through line-pack in the hydrogen backbone and salt caverns in the Netherlands converted from gas storage into hydrogen storage. Imported hydrogen (clean hydrogen) is included each with storage, conversion and flexibility. The Dutch market for hydrogen is connected to Germany and Belgium. And finally, the simulation identifies all key consumer segments: industry sectors; housing; transport, each with their own demand pattern (Exhibit 74). The simulations are conducted for 2027 when some regional connected networks and 2030 when the backbone is fully operational.

Exhibit 74: The hydrogen market with its different sources, demand, and dynamics [52]



The model assumes different types of hydrogen as per exhibit 74 hereabove, based on conversion from electricity (electolyzer) and natural gas (SMR or ATR with CCS), hydrogen storage and line-pack, as well as storage of imports (ammonia, LOHC) and conversion of that storage into hydrogen. The model recognizes a diversity of customers each with their own demand patterns. The model connect the RES production locations and the industrial clusters through the back-bone with demand centers in the Netherlands and adjacent countries. The model calculate annual profiles with hourly optimization on variable costs, resulting in hourly prices at regional level, and price difference/convergence depending on transport capacity and congestion. The marginal costs for hydrogen production are determined by the following methodology and input parameters (Exhibit 75) and aspects that are included and excluded in the simulation (Exhibit 76). For instance, given the huge uncertainty about CAPEX investment costs, the capital costs for the electrolyzer and other fixed costs are excluded.

Exhibit 75: Methodology and input parameters [52]

The marginal costs for hydrogen production are determined according to the following methodology (hourly).

$$\text{HYCLICX} = \sum fixOPEX + \frac{Elec\ Price + Elec\ tax + GO}{\eta} + \frac{Spec\ Water\ Cost \cdot Spec\ Water\ Demand}{HHV}$$

Selected cost parameters*		HYCLICX Green	HYCLICX Blue	HYCLICX Grey
	Unit	Electrolysis	CH4 + CCS	CH4 (no CCS)
Operation & Maintanence (O&M), *fixed part*	EUR/MWh	13.72	7.51	6.06
Efficiency (UHV)	%	76.83	82.74	88.65
Electricity and gas levies (incl. Green GOe)	EUR/MWh	7.465	4.01	4.01
Water cost	EUR/m³	4	-	-

Exhibit 75: Starting point spot market modelling [52]

HYCLICX: what is included

Marginal-price costs associated with producing additional MWh of hydrogen

- Electricity spot price (hourly variable)
- Green guarantee of origin for renewable electricity (monthly)
- Tax on electricity demand electrolyser not into stack (auxiliary power)
- Water cost
- O&M costs
- Stack replacement cost

For blue and grey hydrogen:

- Gas price (daily variable), CO2 price (daily variable) and/or CCS storage cost

What is not included

Costs that are independent of producing additional MWh of Hydrogen

- Capital cost of investment of Electrolyser
- Upfront project preparation cost
- Fixed administration and overhead cost
- One-time electricity grid connection fee or cost
- Yearly fixed electricity grid tariff, capacity related
- Hydrogen grid: all shipper tariffs, connection fees
- Cost for other transportation (by ship or trailer)
- Commercial margin

For blue and grey hydrogen:

- Same principles apply as above

The starting point of the spot market modelling is as follows (Exhibit 76), whereby one has to keep in mind the phases in the buildup of the hydrogen system (regional clusters between 2025-27 only; coupled by large scale hydrogen infrastructure and storage (2027-2029); and connections to Germany and Belgium and integrating ammonia from 2030 onwards.

Exhibit 76: Starting point spot market modelling [52]

Starting Point Spot Market Modelling

System simulation

Market design as in power & gas (double-sided, sealed bid, pay-as-cleared, etc.)
Auction-based trading only
Competitive market, i.e. marginal cost bidding
Perfect foresight to all market players
Pareto efficiency minimizes system allocation cost

Assess dispatch dynamics of coupled markets:

- Blue & green H2
- H2 storage & line-pack
- Shipping, conversion and pipelines
- Profile imbalances supply & demand

Market design aspects:
- Hourly vs daily clearing H2

Market simulation

Market design as in power & gas (double-sided, sealed bid, pay-as-cleared, etc.)
Auction-based trading & Long-term contracts
Imperfect private and public foresight
Public and private uncertainty
Tending to pareto efficiency under competitive conditions

Assess impact of alternate contracts, bid behaviour and uncertainty

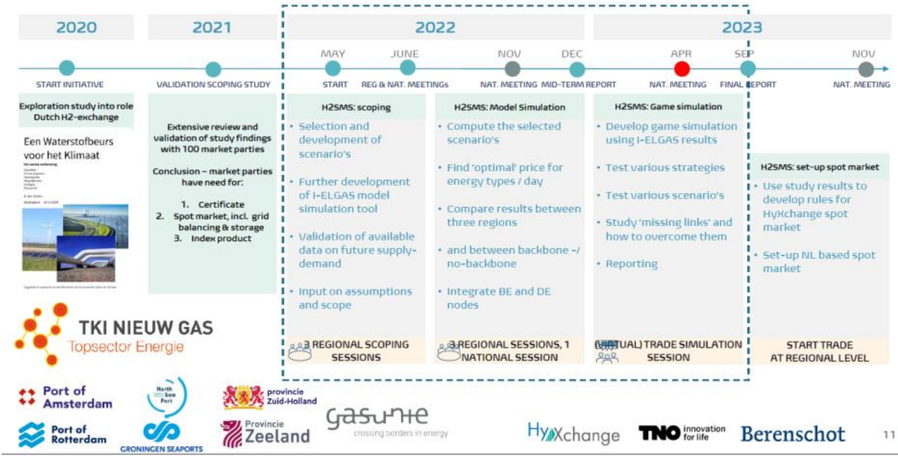
- Differing spot products (like fill-or-kill block bids)
- Alternate contracts (like PPA's)
- Alternate bid strategies (non-marginal cost based)
- Bidding under uncertainty (like weather forecasts)

The simulation is run to better understand the dynamics of the Dutch / Northwest European hydrogen system, both for physical and Guarantees of Origin flows. Purpose of this simulation project is to learn about:

- How do we balance the green production variations (SMR flex, imports, H2storage)?
- What is the timeframe of the daily balancing?
- How does one maintain supply in dunkelflaute/ worst storm situations?
- What are the opportunities for connecting the clusters (+ international)?
- What are possible opportunities for market parties?

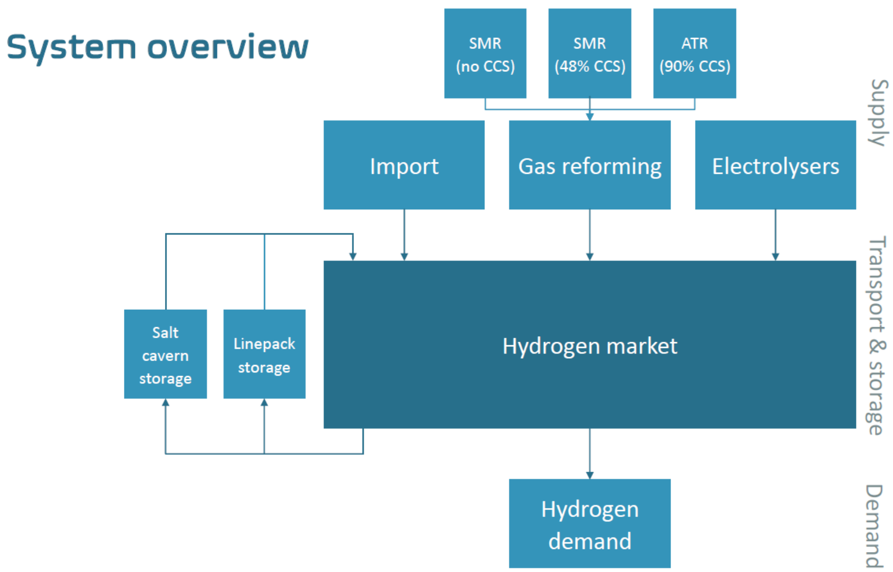
The agenda for the simulation studies is as follows (Exhibit 77)

Exhibit 77: HyXchange (spot market project) development and timeline [52]



The system overview used for the modeling and simulation is as follows (Exhibit 76). The model includes grey, blue and green hydrogen production in the Netherlands, the latter through electrolysis, as well as imports of hydrogen carriers. The model also assumes hydrogen storage in salt caverns.

Exhibit 78: HyXchange system overview [52]



The model has taken the following assumptions, presented in the following exhibits.

Exhibit 79: HyXchange assumptions dispatch simulation - supply [52]

The 2030 scenario contains assumptions for:

- Seaborne (green ammonia) import
  - Costs based on dedicated green ammonia production in Morocco (€30,- /MWh LCOE)
  - 7 Mton NH_3 to 1 Mton H_2 cracker (80% efficiency, marginal cost on hydrogen market €66,- /MWh)
  - *Note: based on feedback during the session additionally blue ammonia import will be added to the simulation. We expect that total import volume in the base case remains equal due to the position of blue ammonia in the merit order / price of imported blue ammonia.*
- Gas reforming
  - SMR (no CCS) with 81% efficiency
  - SMR (+48% CCS) with 77% efficiency
  - ATR (+90% CCS) with 82% efficiency
  - All able to ramp within the hour (assuming oxygen buffer for ATR), no minimum load modelled
- Electrolysers
  - Assumed 75% efficiency (PEM)
  - Subsidy in place for electrolysers to run ≥ 4200 Full Load Hours

Hydrogen by new definitions	Hydrogen by colour	
Renewable hydrogen (sometimes referred to as clean hydrogen)	Green hydrogen (renewable electricity through electrolysis)	Electricity from grid (electrolysis)
Low-carbon hydrogen	Blue hydrogen (natural gas with CCS)	
Fossil-based hydrogen (without CCS)	Grey hydrogen (natural gas), brown hydrogen (brown coal), black (black coal)	

Data source: Author's compilation based on Hydrogen in the Energy Transition, Florence School of Regulation, July 2022.

Exhibit 80: HyXchange assumptions dispatch simulation – transport and storage [52]

Underlying assumptions for the 2030 scenario

The 2030 scenario contains assumptions for:

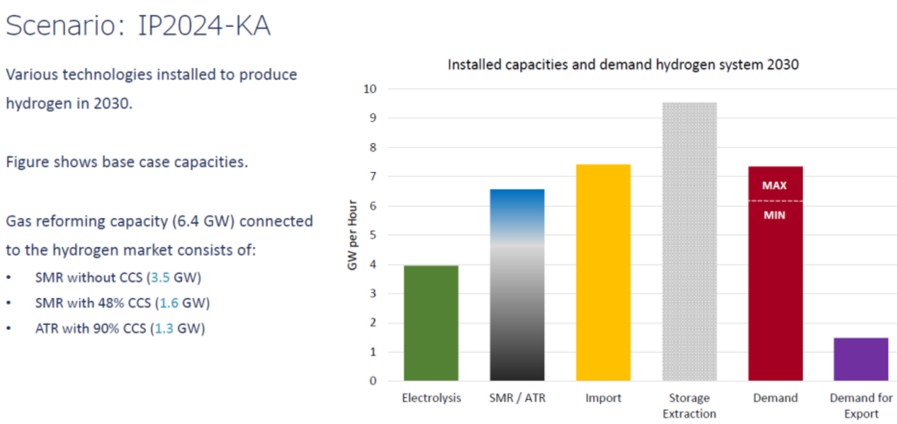
- Hydrogen transport
  - The backbone connects five industry clusters.
  - Model includes an east-west connection, not specified where it is located.
  - Pipeline capacities are assumed not to be limiting transport.
- Hydrogen storage
  - HyStock: four salt caverns at 33 kton capacity hydrogen storage.
  - Linepack: storage with rates relative to cluster demand and production.
- Import options
  - Ammonia as feedstock is not part of the market simulation, as such no choices were made how ammonia is e.g. transported to OCI.
  - LOHCs and other H2 carriers are not included for now. They could provide an alternative to green and blue ammonia depending on their price.

Exhibit 81: HyXchange assumptions dispatch simulation – demand and market [52]

The 2030 scenario contains assumptions for:

- Hydrogen demand & export
  - National demand from IP2024-KA assumes limited fertilizer and TATA demand (44 TWh).
    - We assume 50% hydrogen demand for fertilizers on market (+8 TWh).
    - We assume TATA switching between hydrogen and methane for DRI 1 (+7 TWh) .
    - Total demand Netherlands thus amounts to 61 TWh.
  - 0,5 TWh hydrogen demand in Gent, connected to backbone (Antwerpen area, other demand in Belgium unknown if it is connected).
  - Demand in Nordrhein-Westfalen about 45 TWh, of which 8 TWh sourced in the region.
    - We assume 67% of total demand NRW supplied through Nedersaksen (due to significant planned pipe-capacity and low local demand)
    - Total demand NRW sourced through Netherlands thus amounts to 12 TWh hydrogen.
- Hydrogen market
  - Constraint for industry: 42% of non-by-product hydrogen consumption is green
  - Market clearing is hourly, similar to electricity markets
  - ETS price / CO2-levy of €136,-

Exhibit 82: HyXchange installed capacities – base case [52]



The base case results are presented in exhibits 83 - 86. It is interesting to learn that on their premises the electrolyzers run c. 4,200 hours a year, while ammonia imports are the whole year required in 2030.

Exhibit 83: Results 2030 scenario: Hourly dispatched - base case [52]

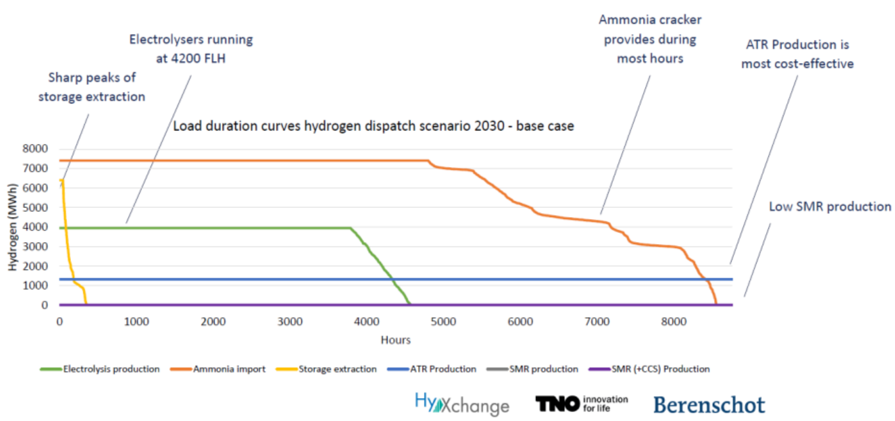


Exhibit 84: Results 2030 scenario: Weekly dispatched - base case [52]

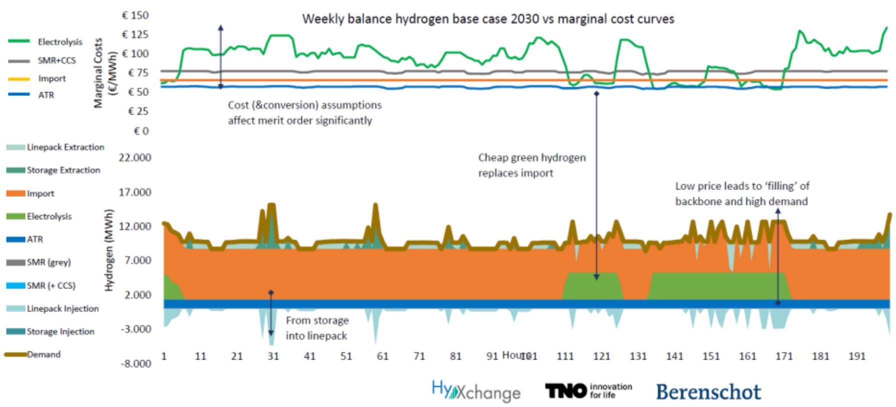


Exhibit 85: Results 2030 scenario: Annual production volumes - base case [52]

- (green) Ammonia imports cover most of the hydrogen demand, due to its relatively low marginal costs
- Limited use of storage due to plenty available flex through import route
- Electrolysis contributes 50% to the green hydrogen demand of 42%

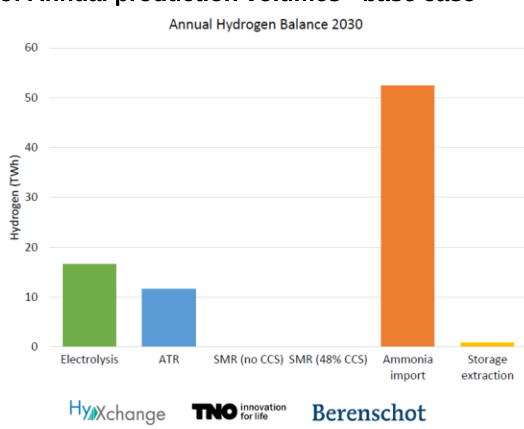
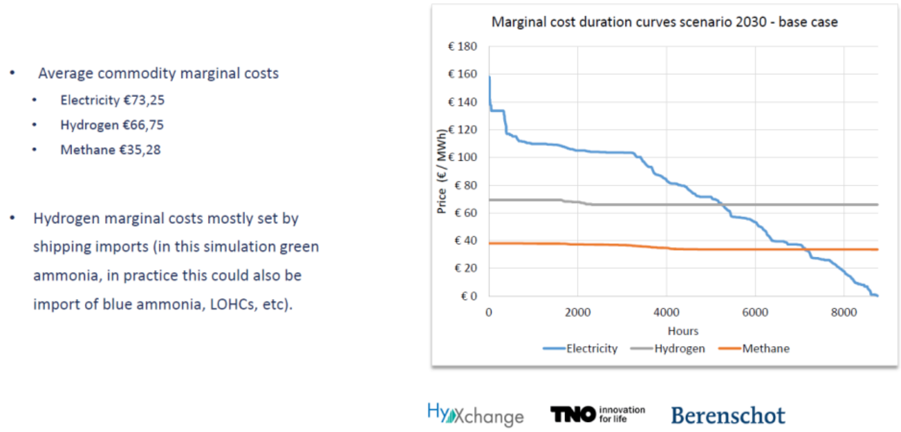


Exhibit 85
Results 2030 scenario: Marginal costs - base case [52]



Subsequently, HyXchange run several variants to the base case, both physical p and market variations, to assess the dynamics of the hydrogen spot market. The HyXchange spot market simulation has been subsequently used to develop the HYCLICX spot market indicator.

On June 7, 2023, HyXchange published its first issue of the hourly HYCLICX spot market indicator for hydrogen based on lowest-priced electricity hours during its EU Green Week event in Brussels. The indicator is an instrument to estimate variable production cost for renewable hydrogen from electrolysis in the Netherlands.

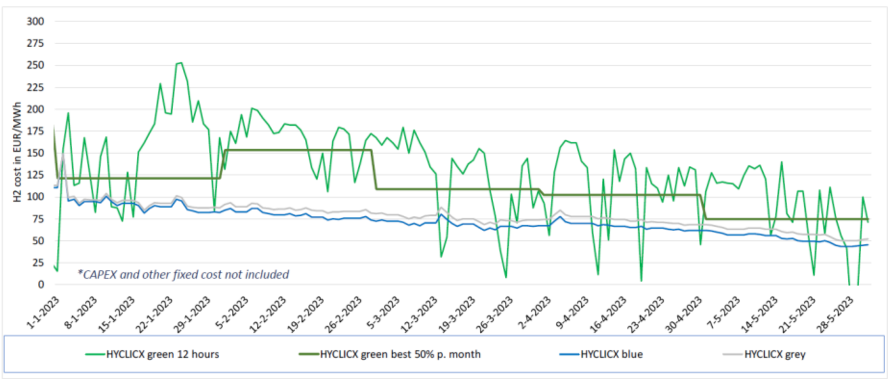
The renewable HYCLICX price indicator is linking the variable price component of hydrogen to the hourly electricity spot market, reflecting the electrolysis as a source for green hydrogen. By selecting the lowest set of volatile hourly power prices, mostly occurring in two varying blocks per day in the Netherlands, hydrogen can be produced in the cheapest way. The hours are largely coinciding with a high share of renewable electricity production from wind and solar, also providing alignment with certificate rules and the EC Delegated Act on hydrogen. As a general main indicator, the HYCLICX publishes the cost price for the lowest-priced 50% of hours of electricity each month. The 505 approach is linked to the average time synchronous availability of renewable electricity

Selected indicators: HYCLICX publishes on a monthly interval a selection of relevant indicators for hydrogen:

- HYCLICX green (daily, 2x 6 hour blocks): The cost price for the cheapest (fixed) 12 hours of electricity each day.
- HYCLICX green (month): The cost price for the lowest-priced 50% of hours of electricity each month.
- HYXCLICX blue (daily): The cost price for blue hydrogen, to allow for comparison.
- HYXCLICX grey (daily): The cost price for grey hydrogen, to allow for comparison.

The HYCLICX will be published on a monthly basis, showing both in detail the hydrogen production price for the previous months as well as the development dating back 1 year. In addition, a weekly update will also become available on our website. The first results are presented here below (Exhibit 86):

Exhibit 86: HYCLICX: January – May 2023, overview [53]



HyXchange

Exhibit 87: HYCLICX: green best 50% between January and May 2023 [53]

Date*	HYCLICX Green best 50% €/MWh HHV var.cost	HYCLICX Green best 50% €/kg var.cost	HYCLICX Green best 50% €/MWh LHV var.cost
January	121,41	4,78	143,51
February	153,38	6,04	181,30
March	109,94	4,29	129,95
April	102,10	4,02	120,69
May	**74,52**	**2,93**	**88,08**
June			
Juli			
August			
September			
October			
November			
December			

- Prices primarily in Eur/MWh HHV higher heating value, full H2 energy content
- Aligned with indexes for natural gas (e.g. TTF), rules of Dutch H2 grid and green G.O
- Conversion factor P/MWhHHV to P/kg: 0.03939 ~ 4 / 100
- Conversion factor MWhHHV to MWhLHV: 1,182

**CAPEX and other fixed cost not included*

HyXchange

The HYCLICX model is based on the following formulae and input parameters (Exhibit 88 and 89):

Exhibit 88: HYCLICX: marginal and total cost formula [53]

The marginal costs for hydrogen production are determined according to the following methodology (hourly).

$$\mathbf{HYCLICX} = \frac{Spec\ Invest \cdot \sum OM}{\eta \cdot FLH} + \frac{Elec\ Price + Elec\ tax + GO}{\eta} + \frac{Spec\ Water\ Cost \cdot Spec\ Water\ Demand}{HHV}$$

$$\mathbf{Total\ cost} = \frac{Spec\ Invest \cdot ANN}{\eta \cdot FLH} + \frac{Spec\ Invest \cdot \sum OM}{\eta \cdot FLH} + \frac{Elec\ Price + Elec\ tax + GO}{\eta} + \frac{Spec\ Water\ Cost \cdot Spec\ Water\ Demand}{HHV}$$

Selected cost parameters*		HYCLICX Green	HYCLICX Blue	HYCLICX Grey
	Unit	Electrolysis	CH4 + CCS	CH4 (no CCS)
Depreciation period	A	20	20	20
WACC	%	8	8	8
Spec. Invest cost	EUR/kWel or EUR/kWh_H2	1000	1450	800
Operation & Maintanence (O&M)	% of Invest	4.42	3.00	4.70
Efficiency (UHV)	%	76.83	82.74	88.65
Electricity and gas levies (incl. Green GOe)	EUR/MWh	7.465	4.01	4.01
Water cost	EUR/m³	4	-	-

**Basic calculation method and most parameters provided by consultant E-bridge, in line with their HYDEX index for hydrogen in Germany. Approach to assess green hydrogen product cost per hour (and select blocks of operational hours) for HYCLICX provided by HyXchange based on its hydrogen market simulation project and discussions with market parties.*

HyXchange

Exhibit 89: HYCLICX: detailed parameters for the calculation [53]

Selected cost parameter		HYCLICX green	HYCLICX blue	HYCLICX grey
	Unit	Electrolysis	Reformer + CCS	Reformer w/o CCS
Lifetime/depreciation period	a	20	20	20
WACC	%	8	8	8
Specific invest cost	EUR/kW_e or EUR/kW_H2	1000	1450	800
OPEX Component for stack replacement	% of invest	2.42	-	-
Operation & Maintenance (O&M)	% of invest	2.20	3.00	4.70
Lower heating value Hi / LHV	kWh/kg_H2	33.32	33.32	33.32
Higher heating value Hs / HHV	kWh/kg_H2	39.39	39.39	39.39
Efficiency (ref. to lower heating value Hi / LHV)	%	65.00	70.00	75.00
Efficiency (ref. to higher heating value Hs / HHV)	%	76.83	82.74	88.65
Full-load hours *(12h, 2 6h blocks per day)*	h/a	4380	7000	7000
Water cost	EUR/m³	4	-	-
Water demand	m³/kg_H2	0.01	-	-
CO2 transport and storage cost (only operational part, no CAPEX)	EUR/t_CO2	-	35	-
CO2 emissions for natural gas	t_CO2/MWh_NG	-	0.201	0.201
Sequestration rate for CCS	%	-	90	0
Additional cost for electricity (Electricity tax and green electricity GO))	EUR/MWh_e	0,115 + 7,35	-	-
Additional cost for natural gas (Gas tax)	EUR/MWh_NG	-	4.01	4.01

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