

Project Progress Report February 2022: FINAL REPORT

Synthesis

<i>Project Name:</i>	ETSAP-TIAM Phase 1 and 2
<i>Coordinating Partner:</i>	CMA MINES Paris
<i>Partners</i>	<p>IER: Markus Blesl, Felix Lippkau UCC/GCEP: James Glynn UCC: Olexandr Balik ESMIA: Kathleen Vaillancourt E4SMA: Maurizio Gargiulo KANORS : Amit Kanudia UCL : Paul Dodds CMA : Sandrine Selosse, Lucas Desport, Sébastien Folio</p>
<i>Starting Date:</i>	<p>January 2018 (with DTU) July 2020 (with CMA) (for the updated proposal) January 2021 (for the effective start due to data sharing restrictions)</p>
<i>Completion Date: (according to the proposal)</i>	<p>June 2019 June 2021 for the updated proposal</p>
<i>Completion Date:</i>	<p>End of 2021 February 2022 (after last modifications)</p>
<i>Budget:</i>	<p>91,455.32€ Expenses:</p> <ul style="list-style-type: none"> • Calculation server: 4,969.52€ • General management costs: 8,891.8€ (4,572.77€+4,319.03€) • KANORS contribution: 69,600€ • CMA contribution: 8,000€
<i>Short Description of progress achieved:</i>	<p>Model developments</p> <p>Until March 2021</p> <ul style="list-style-type: none"> - A first inventory of the contributions of each partner was carried out and organised: <ul style="list-style-type: none"> ○ At this stage of the project, each partner should contribute according to what they had announced <ul style="list-style-type: none"> ▪ Drivers ▪ Stocks, capacities, trades ▪ SSP data ▪ Fossil fuel resource cost curves ▪ Hydrogen sector ○ Teams by subject should be formed ○ Deadline for first contribution from all: 20 April 2021 - A first inventory of the missing items has been made and will be discussed again after the first developments have been submitted - The decision was taken to revert to a breakdown into 15 regions as initially planned due to the short time frame and the lack of data - The tools to be deployed to facilitate the collaboration and developments to be made to the model by the various contributors are ready:

	<ul style="list-style-type: none"> ○ Collaborative work: Slack ○ Developments: Apache Guacamole (virtual machine, HTML5 web application) and calculation server ○ Technical support with e-mail contact <p>Until September 2021</p> <ul style="list-style-type: none"> - The decision was made to follow the development proposal of Amit (he has made progress on a number of developments) - A discussion was held on the possibilities of making the model open access, this is the path that is being followed (subject to decisions made by ETSAP on this issue) - The decision was confirmed to stay to a breakdown into 15 regions as initially planned due to the lack of data (in particular as regards trades) - Lucas and James are working on the drivers and SSP scenarios. - Lucas is going to update hydrogen production technologies. <p>Until November 2021</p> <ul style="list-style-type: none"> - KANORS developments (see documentation) - CMA developments: Hydrogen chain (see documentation) <p>Until February 2022</p> <ul style="list-style-type: none"> - Model review - Last modifications - Bug corrections - IER's developments (see documentation)
<p><i>Deliverables submitted:</i></p>	<ul style="list-style-type: none"> ● The model is available on GitHub and on Veda online (the model was also sent by e-mail to ETSAP) ● A documentation of the model modifications

Documentation – Model updates

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Further developments

✧ Improvements that need to be done	p.27
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ETSAP-TIAM 2.0

February 7, 2022

This is a summary of the changes made since mid-June 2021.

There is one base-year template for each sector, and energy/emissions (by region and sector) are calibrated to IEA Balances in 2018. Supply (upstream) and electricity sectors have been rebuilt from scratch. End-use sectors still largely rely on the “fuel split by energy service” assumptions of the original TIAM model, but they are much easier to review and change now. There have been major updates in existing/new technology harmonization in all sectors. New techs in transport have been consolidated. New techs that were defined for Industry have been moved to base-year template.

1 Primary energy

Primary energy modeling has been done from scratch.

- 1.1. Each region has a 21-step supply curve, with the base quantity as INDPROD. Base prices, step sizes and elasticities are assumptions.
 - 1.1.1. Energy forms: hard coal, brown coal, coking coal, crude oil, Natural Gas, Industrial and municipal waste, biogas.
 - 1.1.2. NGL is an output of Gas extraction, based on base-year shares from IEA

2 Transformation

Transformation sector has been done from scratch.

- 1.2. Refineries, Coke ovens, blast furnace, transfers, coal to liquids, gas blending
 - 1.2.1. E* used for energy consumption where applicable
 - 1.2.2. Base-year operation fixed
 - 1.2.3. Future bounded for generic transfers and increasingly free for Refineries

3 End-use

The end-use sectors have been restructured, but no new data or assumptions have been introduced.

3.1 Industry

Efficiency assumptions in existing techs were inconsistent. New techs have been removed from the SubRES and moved to base-year template. Future efficiencies and shares can be controlled very easily via scenario files.

3.2 Transport

Future vintages were defined as individual technologies. Vintages have been collapsed into single techs, and efficiency of the “base” future tech has been used for calibration.

3.3 Residential, Commercial, and Agriculture

These sectors have changed the least of all. The main change is to remove the urban/rural split that existed in demands like heating and cooling.

4 Demand projection

Demand projections have been done from scratch.

4.1.1 Drivers

10 sets of GDP projections (IIASA/OECD X SSP1 – SSP5) and 5 sets of population projections downloaded from <https://tntcat.iiasa.ac.at/SspDb/> and aggregated into TIAM regions. There are two sample driver scenario files, which are set up to switch to a different model/SSP very easily.

4.1.2 Elasticities

Only three series have been used – for developed regions, emerging, and an intermediate one for China.

5 Trade

Generic Global markets have been created for 29 commodities: BIOBSL, BIOCHR, BIODST, BIOGSL, COABCO, COACOK, COAHCO, COAOVC, COATAR, ELC, GASETH, GASNGA, OILASP, OILCRD, OILDST, OILFEE, OILGSL, OILHFO, OILJTK, OILKER, OILLPG, OILLUB, OILNAP, OILNCR, OILNGL, OILNSP, OILPTC, BIODST, BIOGSL. Rough transportation costs for coal, gas, and oil have been estimated from EIA data.

6 Power

This has been rebuilt from scratch, and it draws heavily on the work done on the International Electricity Market Module (IEMM in the WEPS+ framework) for Energy Information Administration (EIA, USA) over the past several years.

6.1 Existing stock and new technologies (conventional)

Unit-level information from Platts is aggregated into model plant types, fuels, and regions, by vintage. Efficiencies are assigned to each vintage/size/type configuration based on US data and regional multipliers. Operation and maintenance (O&M) costs are assigned based on IEA data.

New fossil and nuclear capacity options are available for endogenous model investment. Capital costs and efficiencies have been shaped by regional multipliers, to incorporate local costs of materials, labor, policies, etc. Fossil O&M costs are assigned based on IEA data. Nuclear O&M costs are provided by the WEPS+ nuclear module.

6.2 Renewable potential and cost

Detailed country-level potentials for onshore and offshore wind, photovoltaic, and hydro capacity have been used. Wind potentials are segmented by resource class, distance from transmission, and, for offshore wind, depth. Each country-level segment has its own cost, resulting in a detailed global wind supply curve. PV potential is similarly segmented by resource class within each country. Hydro is specified by a three-step cost supply curve.

Hourly wind and solar generation profiles for each country were developed from geospatial solar and wind speed data. These are aggregated into the model timeslices.

Country-level availability factors constrain hydro production at the annual and seasonal level, based upon historic seasonal generation where available, or seasonal precipitation data. Moderate (20 percent) additional seasonal flexibility is provided to represent the capacity for reservoirs to allow seasonal shifting of production.

All these options for new renewable installations are then made available to the model and tracked at the country level, regardless of regional aggregation, to maintain the granularity of the resource supply curve and prevent resources from supplying inappropriately distant load without incurring transmission costs.

6.3 Demand load shapes (COM_FR)

To convert annual sector loads to time-sliced load shapes, sector archetype load shapes have been developed from country-level 8760 hourly load data, where available, along with historical annual sector consumption shares. Because sector-specific load data is rarely available, sector archetypes are based upon assumptions that shapes in the industry and commercial sectors can be expected to vary with season and time-of-day in roughly predictable ways.

From the 8760 load curves, first the deviation of monthly average load from the annual average is computed and apportioned to the end use sectors. Industrial load is assumed to contribute only 10%, because industrial facilities tend to operate at a similar level all year. The remainder of the monthly deviation is then allocated to the commercial and residential sectors, according to historical consumption shares.

A similar procedure is then used to apportion the variation of average hourly load within each month. First, a "flattened" industrial portion of the deviation is calculated. Then, a profile for hourly commercial load, based upon the assumed time course of daily lighting, equipment, and space conditioning demands, is used to shape the commercial deviation. Finally, the remaining deviation is assigned to the residential sector.

These procedures result in country-level load shape archetypes for each sector with 288 slices each (12 months times 24 hours). These are then converted into power units using the most recent historical sector consumption level, to allow consumption-weighted aggregation of country shapes to the regional level. Countries without historical 8760 data receive user-assigned shapes from a country with similar climate and economic characterization. The 288-slice archetypes are then aggregated to the model timeslices.

The resulting time-sliced sector archetypes are assigned as the COM_FR to demands from the respective sectors. [Scen_Base_Electricity sheet YFRs]

6.4 Controlling Solar and Wind penetration

[Scen_Base_Electricity sheets UCs and Grids_Bounds]

Electricity demand at the regional level is supplied by country-level resource tranches. In multi-country regions, as well as in large countries, resources may not be located near loads, and transmission capacity may not exist from resources to load. We do not want the model satisfying an unrealistic portion of regional load with renewables that may be in a small and potentially distant portion of the model region.

To provide a generic structure to control the penetration of these technologies, each *country* is allowed to produce a maximum level of generation from wind-plus-solar before it must incur a grid extension cost. To allow generation beyond that limit, three levels of "grid extension" investment, notionally representing short distance, medium distance, and long-distance transmission, have been provided each with assumed bounds and investment costs.

The bounds for the initial maximum generation and the three levels of grid extension are initially driven by projected country load, based upon a logistic curve that is fitted to minimize the sum of squared errors of per capita consumption from historical values and population projections.

For each country n , a user constraint requires:

$$\begin{aligned} \text{Annual Generation from VRE}_n \\ \leq \delta \times \text{ProjectedLoad}_n + (\text{SDGrid}_n + \text{MDGrid}_n + \text{LDGrid}_n) \times 8.76 \end{aligned}$$

The maximum capacity of each of the three additional "grids" is bounded as a share of *Projected Load (PL)*:

$$SDGrid_n \leq \alpha \times PL_n / 8.76$$

$$MDGrid_n \leq \beta \times PL_n / 8.76$$

$$LDGrid_n \leq \gamma \times PL_n / 8.76$$

Values $\delta = 0.25$, $\alpha = 0.2$, $\beta = 0.2$, and $\gamma = 1.25$ are arbitrary assumptions that can be revised, if needed. Similarly, costs for short/medium/long distance grids are assumed to be \$900/1350/2025 per GW, which can be revised easily.

Note that these constraints are implemented at the *country* level, regardless of how countries are aggregated into model regions. They are intended to prevent, for example, Iceland's abundant wind resources from powering all of Europe's load, without appropriate transmission investment.

Similar constraints may be added to prevent over-utilization of hydro resources in countries with large potential, without corresponding transmission investment.

6.5 Data sources

Existing generation stock: The Platts UDI World Electric Power Plants Database (WEPP) is used for existing/under construction capacity by country and state. Capacity and generation for historical model years are calibrated to EIA International Energy Statistics data.

Operating and maintenance costs: Country-level O&M costs are based on the 2010 and 2015 IEA Generation Cost studies¹, which provide national O&M cost estimates for new units. Due to incomplete coverage, countries were divided into five reporting peer groups, and data from the Bureau of Labor Statistics on international wage differentials was used to establish which countries were most closely aligned in labor costs. On this basis, non-reporting countries were assigned to a peer group paired with countries that did report. Calculations based on the two capacity factor scenarios IEA reported were used to distinguish fixed and variable O&M. Data from the recent Sargent & Lundy study for EIA on operating costs of US generation was used to develop ratios for large versus small units. This ratio was applied to the base costs for all countries.

Wind and solar potential: Wind resource data by country come from a resource assessment performed at the National Renewable Energy Laboratory (NREL) based on the National Center for Atmospheric Research's (NCAR) Climate Four-Dimensional Data Assimilation (CFDDA) mesoscale climate database². Resources are defined by country and resource quality. Onshore supply curves are further differentiated by distance to nearest large load or power plant, and offshore by distance to shore and water depth. Resources are calculated from hourly wind velocity vectors at a 40km grid at 90m hub heights. Output is derated for outages and wake losses to obtain the net capacity factor. Protected, urban, and high-elevation areas are fully excluded, and certain land cover types are fractionally excluded. Offshore, area within 5 nautical miles of or farther than 100 nautical miles from shore are excluded, as are protected marine areas. Marine areas are assigned to countries based on exclusive economic zones; unassigned or disputed areas are excluded.

¹ <https://www.oecd-neo.org/ndd/pubs/2015/7057-proj-costs-electricity-2015.pdf>

² <https://catalog.data.gov/dataset/global-cfdda-based-onshore-and-offshore-wind-potential-supply-curves-by-country-class-and-912c6>

The following resource categorizations are used by NREL:

Onshore wind is categorized by its:

- Distance to transmission
 - Near: 0-80 km
 - Trans (a.k.a., transitional): 80-161 km
 - Far: > 161 km
- Resource class (C1-C9)

Offshore wind is categorized by its:

- Water depth
 - shallow: 0-30 m
 - trans (a.k.a., transitional): 30-60 m
 - deep: 60-1,000m
- Distance to transmission (Near, Inter, Far)
 - Near: 0-80 km
 - Trans (a.k.a., transitional): 80-161 km
 - Far: > 161 km
- Resource class (C1-C8)

The estimated solar potential is obtained from NREL and represents an annual average of the daily total solar resource averaged over surface cells of 10km resolution at the country-level. The data is based on the State University of New York/Albany (SUNY) satellite radiation model, which uses hourly radiance images from geostationary weather satellites, daily snow cover data, and monthly averages of atmospheric water vapor, trace gases, and the amount of aerosols in the atmosphere to calculate the hourly total insolation (sun and sky) falling on a horizontal surface output over 12 years (1998-2009). The values returned are kilowatt hours per square meter per day (kWh/m²/day) available to fixed, flat plate systems tilted toward the equator at an angle equal to the latitude. The total solar resources within each country are then organized by class, starting at 3 kWh/m²/day or less and increasing in 0.5 kWh/m²/day increments with the highest solar class being 6 kWh/m²/day or more. Each solar class in each country is then converted into total potential solar energy available per year as a function of land area per solar class, conversion efficiency (10%), and number of days per year (365).

Hydro potential and generation profile: Hydropower potential and installed cost are based on Gernaat et al. (2017)³, in which only data for river power plants (or conventional hydropower) was evaluated. Currently, countries with specific cost and potential include Angola, Argentina, Australia, Bolivia, Brazil, Cameroon, Canada, Central African Republic, Chile, China, Colombia, Congo (Brazzaville), Democratic Republic of Congo, Egypt, Ethiopia, France, Gabon, India, Indonesia, Italy, Japan, Madagascar, Malaysia, Mexico, Mozambique, Myanmar, Nepal, New Zealand, Pakistan, Papua New Guinea, Peru, Russia, Sudan, Tanzania, Turkey, Uganda, United States, Venezuela, Vietnam, and Zambia. Countries with no specific installed cost information use regional costs, which are based on

³ Gernaat, D. E. H. J., Bogaart, P. W., Van Vuuren, D. P., Biemans, H., and Niessink, R. "High-resolution assessment of global technical and economic hydropower potential," *Nature Energy*, Vol 2 (October 2017), p. 821-828.

data from International Renewable Energy Agency (IRENA, Renewable Power Generation Costs in 2017) and Oak Ridge National Laboratory (ORNL).

The annual availability factor for hydropower generation for each country is an average capacity factor, calculated from historical (2000 to 2015) capacity and generation data from EIA International Energy Statistics. Monthly capacity factor is based on historical hydro generation for OECD countries, Argentina, Brazil, China, Colombia, India, Russia, and Vietnam. For other countries with no historical hydro generation, monthly capacity factor is based loosely on monthly share of precipitation.

New database on hydrogen production

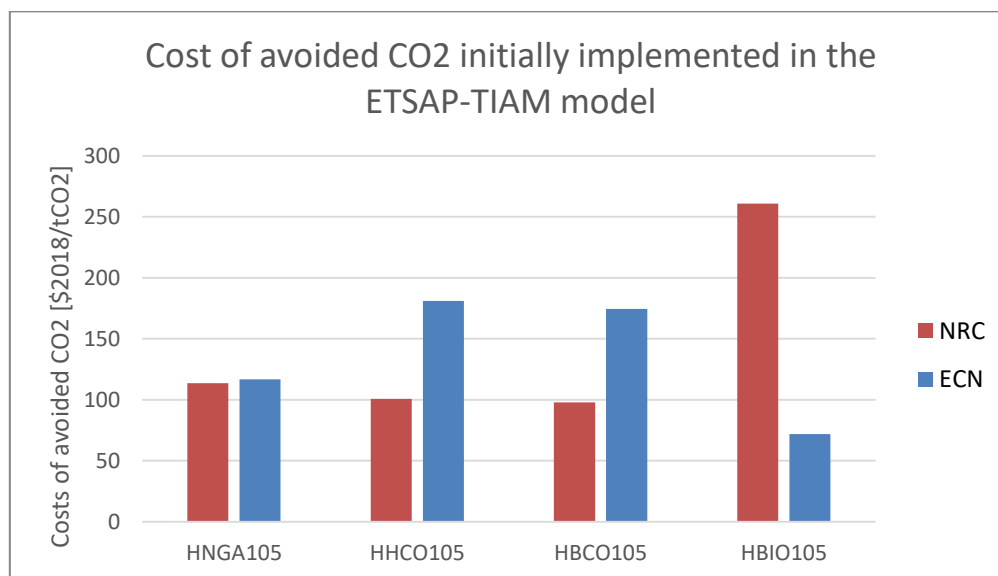
Lucas DESPORT, CMA

Foreword

These developments on the ETSAP-TIAM model mainly concern the hydrogen sector, especially the update of the production processes including grey, blue, and green hydrogen.

Modelling blue hydrogen involves modelling CO₂ transport and storage, that was added the SubRES_CO₂ Sequestration to the model. This SubRES is coming from the old ETSAP-TIAM model.

The initial representation of hydrogen production is in fact double: one in the SubRES_HydrogenECN, and one other in the SubRES_SequestrationC. Analyzing the associated FI_T tables, we calculated the costs of avoided CO₂ for both SubRES and realized that they are not in line with current trends, notably SMR and coal gasification being too expensive (IEAGHG, 2017). Same conclusion for the electrolysis process with a CAPEX of roughly 2600 \$2010/kWH₂ (Schmidt et al., 2017). We also realized that there are big differences from one reference to another. Besides, quite old data (2011) is used to describe the performances of the hydrogen value chain.



Facing this gap, CMA handled the update of the production part by reviewing the literature and gathering expert's opinions of TotalEnergies, the ETSAP working group and the MIT. The final purpose is to build a transparent database the most representative of current trends and showing clearly the assumptions that make up de DB, so that we would be comfortable in justifying our technology assumptions underlying the outputs. One can notice that the transparency of hydrogen-

related assumptions is often neglected in research works, (e.g. (IEA, 2021)), so data rely solely on publicly available documents.

In this document, the assumptions about the performances and costs of each production route, present and future are justified one by one. At the end, the new database that would be used in our model to describe the hydrogen production sector and compare the production routes with various indicators is presented.

Methodology

The literature review points out that there are large ranges of values to describe the costs (mainly CAPEX or directly LCOH) and the performances (lifetime and efficiencies) of hydrogen process. Most of scientific publications focus on specific production routes such as electrolysis or SMR (Binder et al., 2018; Chen et al., 2012; Christensen, 2020; IEAGHG, 2017; IRENA, 2020; Yates et al., 2020). Thus, it is difficult to find a detailed and referenced database that integrates all production routes. But, when implementing a new value chain (here hydrogen) we need to give the model a certain hierarchy in terms of techno-economic performances of each link of the chain to 1) be as realistic as possible and 2) be able to analyze the results ultimately.

One option could have consisted in gathering one by one the information contained in each TEA for each production route, in a bottom-up manner. This methodology was found difficult to apply because each TEA is subject to too many assumptions related to the context of the study so that it is hard to make cross-comparisons. To illustrate that volatility, Table 1 below shows the large range of values depending on the reference considered.

Table 1: some values of CAPEX for coal and natural gas routes

Technology	CAPEX [\$/kW]	Reference
Coal gasification	966	JRC-EU-TIMES (Sgobbi et al., 2016)
Coal gasification	2670	IEA - The Future of Hydrogen
SMR	313 - 1149	JRC-EU-TIMES
SMR	900	IEA - The Future of Hydrogen
SMR	671	IEA - Technology Roadmap

N.B.: all costs and performances are expressed in \$2018/kWh₂ (LHV).

However, a unique review paper concentrating on all production routes and estimating the levelized cost of hydrogen (LCOH) at the facility gate (Parkinson et al., 2019) gives the desired hierarchy between each production route (see Figure 1) but without providing other important details on the performances of the processes (CAPEX, OPEX, efficiency, lifetime, etc.), present and future.

Table 4 Summary of the cost inventories available in the literature from Section 4 compared to the re-estimates in this study. Literature estimates are a summary of the full range of literature values presented in Section 3

Technology	Literature estimates (\$ kg ⁻¹ H ₂)			Our estimates (\$ kg ⁻¹ H ₂)		
	Low	Central	High	Low	Central	High
SMR	1.03	1.26	2.16	1.03	1.26	2.16
SMR w. CCS ^a	1.22	1.88	2.81	1.93	2.09	2.26
Coal	0.96	1.38	1.88	0.96	1.38	1.88
Coal w. CCS ^b	1.4	2.17	3.6	2.24	2.46	2.68
CH ₄ pyrolysis ^c	1.03	1.75	2.45	1.36	1.76	1.79
Biomass	1.48	2.24	3.00	1.48	2.24	3.00
Biomass w. CCS ^d	—	2.27	—	3.15	3.37	3.6
Electrolysis wind ^e	3.56	5.24	10.82	4.61	7.86	10.01
Electrolysis solar ^e	3.34	8.87	17.3	7.1	12.00	14.87
Electrolysis nuclear ^e	3.29	4.63	6.01	4.99	6.79	8.21
S-I cycle	1.47	1.81	2.71	1.47	1.81	2.71
Cu-Cl cycle	1.47	2.13	2.7	1.47	2.13	2.7

Figure 1: Estimations of production costs (Parkinson et al., 2019)

As a matter of fact, the main components of hydrogen production costs are the supported by fuel expenditures and the CAPEX (NREL, 2018). As the cost of fuel is determined upstream in TIMES modelling, the crucial information we need to retrieve from the production costs of (Parkinson et al., 2019) is the CAPEX of each installation, in a top-down approach.

$$CAPEX = \frac{OH}{CRC} \times \left(LCOH - \frac{FIXOM}{OH} - VAROM - FC - T\&S \right) \quad (1)$$

Where:

- *OH* are the operating hours based on the availability factor [in hours]
- *CRC* is the capital recovery charge [%/year]
- *FIXOM* is the fixed operating and maintenance costs [\$/kW.y]
- *VAROM* is the variable operating and maintenance costs [\$/kWh]
- *FC* is the fuel cost [\$/kWh], given in (Parkinson et al., 2019), see Table 2
- *T&S* is the cost of transport and storage of CO₂ [\$/kWh] (only for CCS plants naturally)

This sure requires making assumptions on the parameters above, but it appears that those values are not really discussed in the literature. As a matter of fact, I assume that the *FIXOM* value is a certain ratio of the CAPEX value. Consequently, I calculate the *CAPEX* value with the following equation:

$$CAPEX = (LCOH - VAROM - FC - T\&S) \times \frac{OH}{CRC+R} \quad (2)$$

Where:

- *R* expressed the percentage of CAPEX used to calculate *FIXOM* with $FIXOM = R \times CAPEX$

Assumptions

General assumptions

I assume no electricity importation for fuel-based plants (only the fuel). About the economic life of projects, I assume that the production units without CCS run for 25 years, and 20 years for production units with CCS, considering that the capture units are not expected to last as long as the production unit itself. The capture ratio is set on 90%. I set the availability factor at a maximum of 90% for every process. I also assume a discount rate of 10% for all production routes. The emissions factors report direct CO₂ emissions only.

From the scenarios presented in Figure 1, I select the central scenario of their literature review (“Literature estimate – Central”), that I call CentralBase, plus the three scenarios produced by the authors (“Our estimates – Low, Central and High”). For each of those four scenarios, here is the cost of fuel assumed by the authors.

Table 2: Fuel costs by scenario (Parkinson et al., 2019)

Parameters	Unit	CentralBase	Central	Low	High
Natural gas cost	USD/GJ	4,0	4,0	3,3	8,4
Coal cost	USD/GJ	2,0	2,0	1,3	2,7
Biomass cost	USD/GJ	4,0	4,0	2,9	5,0
Electricity cost	USD/kWh	0,07	0,07	0,07	0,07

I point out that, for electrolysis processes, the values of Parkinson et al. have not been used. Other literature references helped (see section Electrolysis routes)

For the CCS routes, the cost of T&S is sure included into the LCOH but varies from 0 to 16 \$/tCO₂ according studies. I did not find the cost of T&S the authors assumed in their own estimation, so I set it empirically to 10 \$/tCO₂.

The coal gasification route w/wo CCS

Table 3: Assumptions for coal gasification w/wo CCS

Parameter	Unit	Value woCCS	Reference	Value wCCS	Reference
FIXOM	%CAPEX	5%	IEA - The Future of Hydrogen	5%	IEA - The Future of Hydrogen
VAROM	\$/GJ	0,19	JRC-EU-TIMES	0,26	JRC-EU-TIMES
Efficiency LHV	%	60%	IEA - The Future of Hydrogen	58%	IEA - The Future of Hydrogen
Emissions	tCO ₂ eq/tH ₂	20,2	IEA - The Future of Hydrogen	2,1	IEA - The Future of Hydrogen

For the FIXOM values, I found only one other reference (IAMC, 2021) assuming a ratio of CAPEX of roughly 3% (calculated value), much lower than the one assumed here. About the efficiency, there is

only a small decrease due to the highly CO₂-concentrated flue gas of the gasification unit, requiring little additional energy to capture the CO₂, which explains the low costs of avoided CO₂ (see section

Cost of avoided). This “two-points-of-percentage decrease” seems to make consensus in the literature for the same reasons.

Table 4: CAPEX decrease assumptions for coal gasification with CCS (IEA, 2015)

Year	CAPEX decrease
2030	-23%
2050	-27%

I emphasize that the decline in cost for coal gasification only concerns assets equipped with capture units. Noteworthy, in The Future of Hydrogen, IEA assumes no cost decrease at all for coal gasification routes (IEA, 2019), contrary to the Technology Roadmap (IEA, 2015). I take the position that the cost of capture units will decline over time, but the cost decrease of the gasification units themselves is negligible.

The SMR route w/wo CCS

Main information here is that important additional costs are due to the capture unit, as well as additional electricity needs to run it. The loss in efficiency is higher than that of coal gasification because of the flue gas that is less concentrated for SMR.

Table 5: Assumptions SMR w/wo CCS

Parameter	Unit	Value woCCS	Reference	Value wCCS	Reference
FIXOM	%CAPEX	5%	IEA - The Future of Hydrogen	3%	IEA - The Future of Hydrogen
VAROM	\$/GJ	0,09	JRC-EU-TIMES	0,62	JRC-EU-TIMES
Efficiency LHV	%	76%	IEA - The Future of Hydrogen	69%	IEA - The Future of Hydrogen
Emissions	tCO ₂ /tH ₂	8,9	IEA - The Future of Hydrogen	1,0	IEA - The Future of Hydrogen

The cost decrease is assumed both for assets with and without CCS. This assumption stems from the fact that large capacities of SMR with CCS are expected to be developed, so consequently cost improvement are expected on the SMR unit itself. The values come from the Technology Roadmap.

Table 6: CAPEX decrease assumptions for SMR (IEA, 2015)

Year	CAPEX decrease woCCS	CAPEX decrease wCCS
2030	-20%	-49%
2050		-51%

The biomass route w/wo CCS

I noticed that there is a broad knowledge gap in the biomass gasification route, even more with carbon capture. This is due to the low TRL of these technologies. I find strange that the VAROM is the same with and without CCS, according the JRC. I find lower efficiencies than coal and gas routes that have an impact on the CAPEX estimation, as the results show. I also have to assume a certain energy content of the solid biomass gasified in order to calculate the cost of fuel in \$/GJ.

Table 7: Assumptions for the biomass route

Parameter	Unit	Value woCCS	Reference	Value wCCS	Reference
FIXOM	%CAPEX	5%	IEA - Technology roadmap	5%	IEA - Technology roadmap
VAROM	\$/GJ	1,09	JRC-EU-TIMES	1,09	JRC-EU-TIMES
Efficiency	%	55%	JRC-EU-TIMES	36%	JRC-EU-TIMES
LHV					
Emissions	tCO ₂ /tH ₂	0		-11,7	Parkinson et al.
LHV biomass	GJ/t	19	(Forest Research, 2021)		

For costs decrease, I make the same assumptions as for the coal route.

Table 8: CAPEX decrease assumptions for biomass gasification with CCS

Year	CAPEX decrease
2030	-23%
2050	-27%

Electrolysis routes

For the electrolysis routes, I did not consider the findings of Parkinson et al. because they provide aggregated data that are not based on the electrolysis technology (PEM, alkaline SOEC) but the source of the electricity (nuclear, PV or wind), while TIMES models decide upstream on the electricity mix. For this emergent route, I drew most of my assumptions from the DNV-NL report which is quite exhaustive regarding the details on values and their evolution in the future. I decided not to integrate the SOEC technology because of its too low TRL and the big underlying assumptions about the future performances of this technology.

Figure 9: Assumptions for the electrolysis process (DNV-GL, 2020)

Technology	CAPEX	unit	VOM unit	FOM unit	Efficiency/ losses	unit	TRL	Year
Alkaline Elect.								
Low	450	EUR/kWe	52.9 kWh/kgH ₂		63.0 %			2019
High	1260	EUR/kWe	47.6 kWh/kgH ₂		70.0 %			2019
Today (2020)	700	EUR/kWe	52.0 kWh/kgH ₂	2.0 % of CAPEX p.a.	64.1 %		9	2020
Future (2030)	621	EUR/kWe	49.0 kWh/kgH ₂	2.0 % of CAPEX p.a.	68.0 %			2030
Future (2040)	539	EUR/kWe	48.0 kWh/kgH ₂	2.0 % of CAPEX p.a.	69.4 %			2040
Future (2050)	497	EUR/kWe	47.0 kWh/kgH ₂	2.0 % of CAPEX p.a.	70.9 %			2050
PEM Elect.								
Low	990	EUR/kWe	59.5 kWh/kgH ₂		56.0 %			2019
High	1620	EUR/kWe	55.5 kWh/kgH ₂		60.0 %			2019
Today (2020)	1160	EUR/kWe	55.0 kWh/kgH ₂	2.0 % of CAPEX p.a.	60.6 %		8	2020
Future (2030)	663	EUR/kWe	50.0 kWh/kgH ₂	2.0 % of CAPEX p.a.	66.6 %			2030
Future (2040)	497	EUR/kWe	48.0 kWh/kgH ₂	2.0 % of CAPEX p.a.	69.4 %			2040
Future (2050)	414	EUR/kWe	47.0 kWh/kgH ₂	2.0 % of CAPEX p.a.	70.9 %			2050
SOEC Elect.								
Low	2,520	EUR/kWe	45.0 kWh/kgH ₂		74.0 %			2019
High	5040	EUR/kWe	41.1 kWh/kgH ₂		81.0 %			2019
Today	3083	EUR/kWe	41.0 kWh/kgH ₂	1.0 to 2.5 % of CAPEX p.a.	81.3 %		5 to 7	2018
Future (2030)	1706	EUR/kWe	37.7 kWh/kgH ₂	1.0 to 2.5 % of CAPEX p.a.	88.5 %			2030
Future (2050)	1248	EUR/kWe	37.7 kWh/kgH ₂	1.0 to 2.5 % of CAPEX p.a.	88.5 %			2050

I make one important hypothesis on the economic life of an electrolysis process. I assume that the whole installation lasts 20 years, but the stack needs to be replaced before this time. I take my assumptions of the stack lifetime from (Schmidt et al., 2017), ranging from 6 to 9 years. In terms of modelling, setting the life of an electrolysis facility either on 20 years or 6 years would be incorrect. Thus, I chose empirically to take the average value of stack's lifetime and plant's lifetime. The most rigorous way would be to model the replacement of the stack each 6 to 9 years, but I need to take some time to figure out how to model it.

Results

Calculation of CAPEX for coal natural gas, and biomass routes

In the following paragraph, I show the CAPEX calculated according to the estimate of Figure 1. This only includes the non-electrolysis routes and the scenarios "Central" of the "Literature estimate" as well as the three other scenarios of authors' estimate, as resumed in Table 2.

For the CentralBase scenario, I am comfortable in stating that the CAPEXs are in line with literature, except maybe for the biomass gasification route for which there is poor and contradictory literature. To me, the CAPEX of biomass gasification seems too small compared of the other routes, although consistent with the conclusions of the IEA (Binder et al., 2018). Back to equation (2), the low CAPEX of biomass gasification is mainly due to the high fuel cost, itself due to the low efficiency and the low energy content of biomass. There is also a dramatic decrease of SMR+CCS CAPEX for 2050 (830 \$/kWh₂) which may not be consistent compared to the value without CCS (733 \$/kWh₂). I have reservations about this value even though one can see in next section that the future cost of avoiding CO₂ looks consistent.

Table 10: CAPEX estimation of fossil and bio-based routes in the CentralBase scenario

Technology Unit	CapEx 2020 \$/kWH ₂	CapEx 2050 \$/kWH ₂
Coal gasification	1412	1412
SMR	917	733
Biomass gasification	1653	1653
Coal gasification with CCS	2133	1558
SMR with CCS	1625	830
Biomass gasification with CCS	2731	1995

In the Central scenario, I note one inconsistency that is the CAPEX of Biomass gasification with CCS that is really close than that of coal. Other values look correct to me.

Table 11: CAPEX estimation of fossil and bio-based routes in the Central Scenario

Technology Unit	CapEx 2020 \$/kWH ₂	CapEx 2050 \$/kWH ₂
Coal gasification	1412	1412
SMR	917	733
Biomass gasification	1653	1653
Coal gasification with CCS	2545	1859
SMR with CCS	1964	1004
Biomass gasification with CCS	2731	1995

For the Low scenario, same remarks than for the Central scenario besides that the biomass gasification CAPEX is also smaller than that of coal, *without* CCS, which seems impossible. This is explained the very low LCOH assumed by the authors is the Low scenario, which is 1.48 \$2016/kg.

Table 12: CAPEX estimation of fossil and bio-based routes in the Low Scenario

Technology Unit	CapEx 2020 \$/kWH ₂	CapEx 2050 \$/kWH ₂
Coal gasification	996	996
SMR	575	460
Biomass gasification	574	574
Coal gasification with CCS	2232	1631
SMR with CCS	1706	872
Biomass gasification with CCS	2419	1767

This High scenario is really not consistent since I find CAPEX with capture smaller than assets without CCS for the SMR. This is due to the assumptions took on the CAPEX reduction of SMR with CCS from the IEA (IEA, 2015). So, this hypothesis should be revised for the High scenario.

Table 13: CAPEX estimation of fossil and bio-based routes in the High Scenario

Technology	CapEx 2020	CapEx 2050
Unit	\$/kWH ₂	\$/kWH ₂
Coal gasification	1946	1946
SMR	2253	1802
Biomass gasification	2732	2732
Coal gasification with CCS	2857	2087
SMR with CCS	3125	1597
Biomass gasification with CCS	3058	2234

Cost of avoided CO₂

In this section, I calculate for each scenario, present and future, the cost of avoiding CO₂ for the coal, biomass, and gas routes. Noteworthy, the cost of transport and storage of CO₂ is included.

$$\text{Cost of avoided CO}_2 = \frac{LCOH_{woCCS} - LCOH_{wCCS}}{CO2_{wCCS} - CO2_{woCCS}}$$

From this simple formula, one can see that the High Scenario is showing strange values for the future invalidating again the hypothesis for CAPEX decline. However, with the same assumptions, the Central and CentralBase scenarios appear to be realistic in terms of absolute values. In terms of relative values, SMR is more expensive to decarbonize with CO₂ capture than coal gasification and this is also true for biomass gasification. Again, we have poor information about biomass gasification I do not really know whether this is consistent or not.

Interestingly, the low scenario is related to lower production costs indeed (Figure 1), but higher costs of avoided CO₂, and the contrary is true for the High scenario with high production costs but lower costs of avoided CO₂.

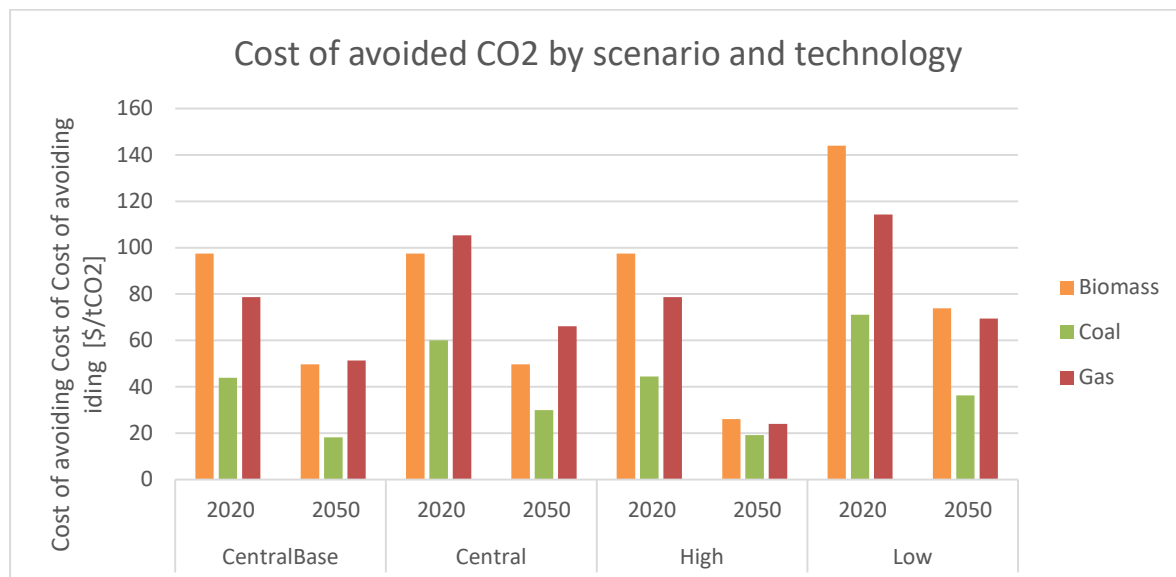


Figure 2: Cost of avoided CO₂ by scenario and technology

The cost of avoided CO₂ is always cheaper for coal but, we need to think in terms of cost of mitigating CO₂ to better appreciate the cheapest assets of both mitigating CO₂ and delivering affordable products. This is what is discussed in the following section.

Cost of mitigating CO₂

In the context of climate mitigation, the levelized cost of CO₂ mitigation (LCCM) is defined as ratio of the financial penalty to environmental gains. To calculate this, the financial penalty must be appreciated compared to the cheapest production route available that is SMR. So, the LCCM of a given technology TECH is

$$LCCM_{TECH} = \frac{LCOH_{TECH} - LCOH_{SMR}}{CO2_{SMR} - CO2_{TECH}}$$

Consequently, the cost of mitigating CO₂ through SMR and CCS is equal to the cost of avoided CO₂ with SMR and CCS.

The estimation of LCCM reveals that the SMR route is the cheapest of the CCS ways to decarbonize hydrogen production. Nonetheless, we note for the Central and Low scenarios in 2020 that the costs of mitigating CO₂ would be lower through biomass gasification. This conclusion is also highlighted by the authors, but they remain prudent knowing that biomass gasification is not currently available. So, I advocate to delay the availability of biomass gasification for 2030. We also note that the LCCM are cheap for the High scenario and coal gasification becomes cheaper than SMR in 2050. Other values look quite consistent.

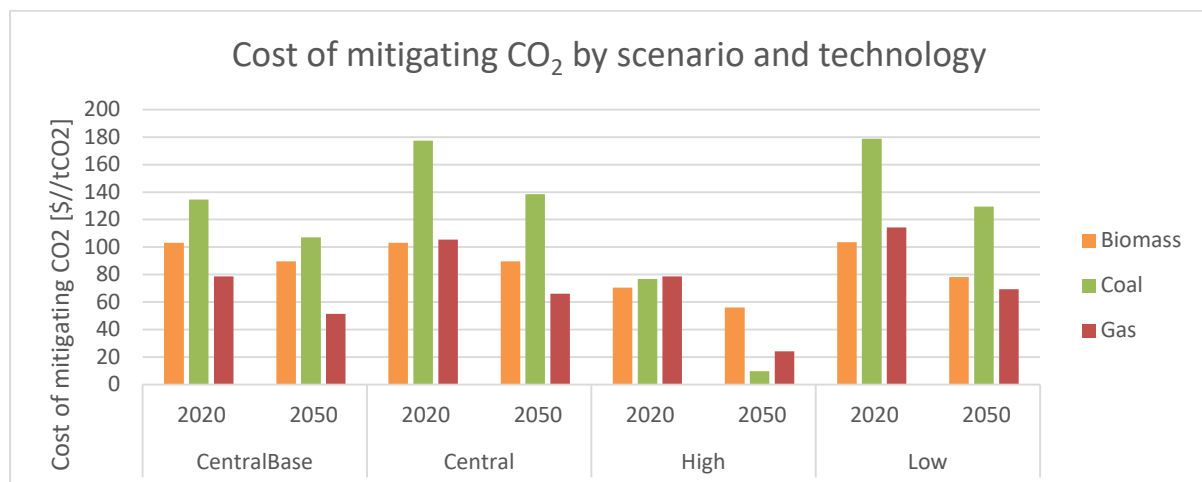


Figure 3: Cost of mitigating CO₂ by scenario and technology

In Figure 4, I explore the competition of SMR with electrolysis processes according to the cost of electricity, in the CentralBase scenario. I assume an electricity carbon footprint of 10 kgCO₂/MWh (EcoInvent). Conclusions are that, in the CentralBase Scenario, PEM and alkaline technologies start competing with SMR and CCS for a cost of electricity between 20 and 30 \$/tCO₂, in the future. Today, the electrolysis technologies are not ready to compete with SMR+CCS even for low electricity costs.

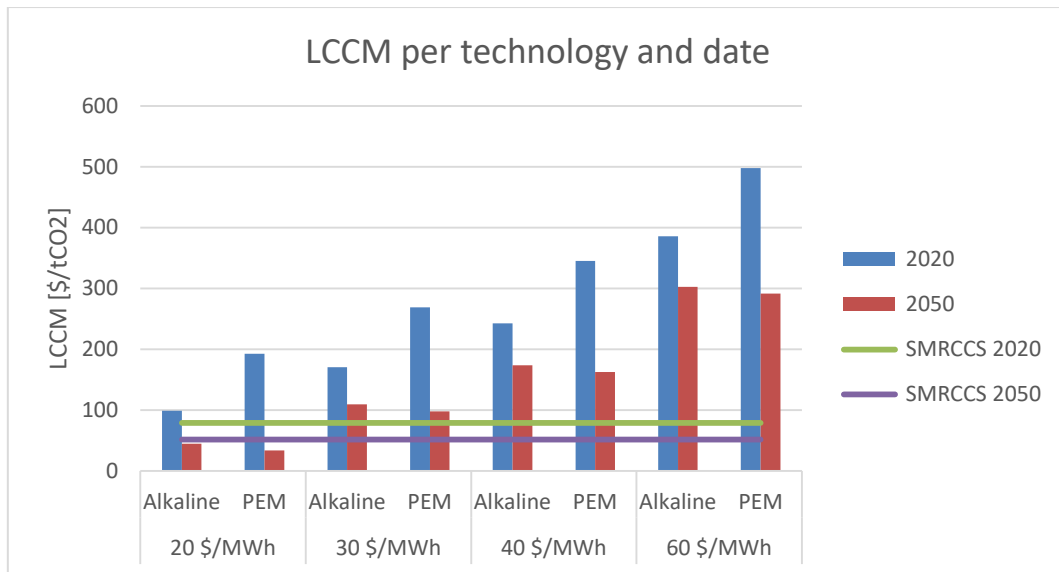


Figure 4: Competition between SMR and electrolysis processes according to the technology and the price of electricity in a CentralBase Scenario

Competition between production routes

Considering only the production costs in the CentralBase scenario, I assess the assumptions I took in terms of CAPEX decrease by calculating the future production costs and thus identify the economic trends for hydrogen production.

In Figure 5, I consider an electricity cost of 60 \$/MWh. The values in blue are those given by Parkinson et al. in Figure 1 but the future costs in orange are calculated considering the assumptions on CAPEX decrease (see section Assumptions). The graph simply shows that SMR with and without CCS as well as coal gasification are the cheapest routes, currently and future for hydrogen production. Electrolysis routes are disqualified due to the high electricity costs they depend on.

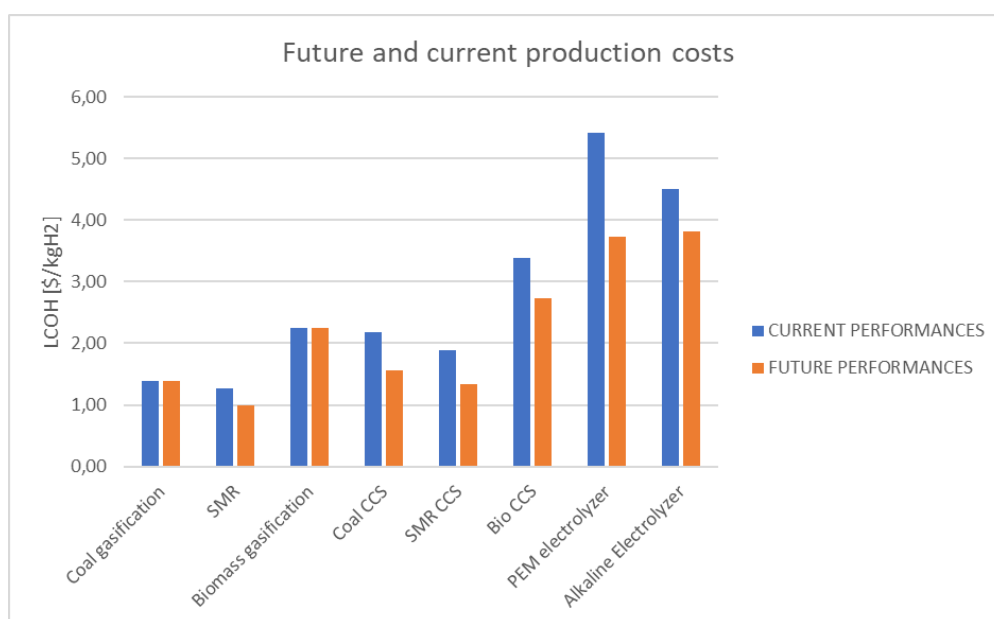


Figure 5: Production costs of hydrogen with a cost of electricity of 60 \$/MWh

If we assume a low cost of electricity (20 \$/MWh), SMR with and without CCS remain the cheapest routes but electrolysis routes start competing with them and with coal gasification. In the future, electrolysis becomes cheaper than biomass or coal gasification with CCS.

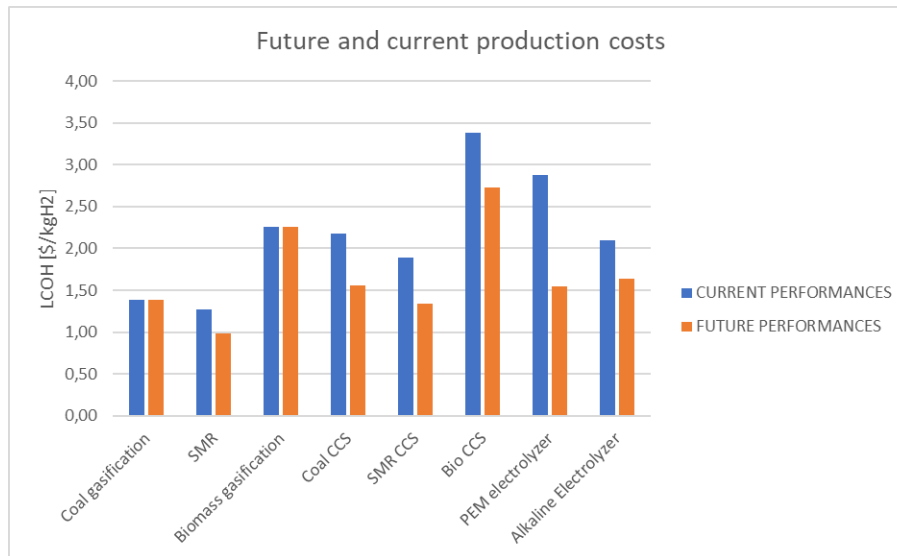


Figure 6: Production costs of hydrogen with a cost of electricity of 20 \$/MWh

Modelling

SubRES_H2

In this SubRES, one can find:

- In the green sheets: the references used for building the new DB
- In Commodities and Processes: only the declared commodities and processes
- In the UPS sheet: the main data with technoeconomic values and assumptions
 - o A table with parameters and assumptions
 - o A colour code to associate an assumption to a reference
 - o In cells N16 and O16, the user can define the scenario to select more or less optimistic data
 - o The calculated costs of avoided CO2 and costs of mitigation
- In the T&S and DMD sheets are the originally implemented processes for the transport and distribution of hydrogen and the vehicles running on hydrogen. No changes have been operated.

SubRES_H2_Trans

In the Param_Transformation sheet, we kept the original regional variation as it was implemented before in the model. In the FLO_EMIS table, I made sure that any emissions coming from a hazardous COMEMI table are cancelled so that we keep control of process emissions directly in the UPS sheet.

SubRES_CO2Sequestration

As there are some capture processes in the SubRES_H2, I implemented the CCS value chain from the original ETSAP-TIAM.

SubRES_CO2Sequestration_Trans

I added a COM_BNDNET table so that any SNK*CO2* commodity in output of CCS equipped hydrogen process is sure to be an input of a SINK* process.

~TFM_INS

TimeSlice	LimType	Attribute	AllRegios	Cset_CN
ANNUAL	FX	COM_BNDNET		SNK*CO2*, 0 SNK*CO2

Conclusion

This work has made it possible to design a database that is dependent on a scenario chosen by the user. I argue that the possibility of this choice is important because the performances of hydrogen production are very dependent on the level of optimism or pessimism. This can also make it easy to study the impact of the cost of hydrogen production on the model results and in particular its competition with CCS or other energy carriers. However, caution should be exercised with the High scenario which still has some inconsistencies that need to be specifically addressed. The CentralBase and Central scenarios seem realistic in terms of production costs, cost of avoided CO₂ and cost of mitigating CO₂, with the difference that the CentralBase is more optimistic on costs.

Besides, one must remain cautious with these calculated data as they are very dependent on the numerous assumptions considered, notably on the fuel costs, which are themselves dependent on the regions of the world. The lifetimes, the regional variability of the CAPEX as well as the costs of transporting and storing CO₂ are other parameters that remain important in the estimation of the cost.

Finally, I am raising attention to the gasification of biomass because the data is still uncertain and diverse in the literature, yet for some of them you get more interesting LCCM than with SMR, which is interesting but strange still. On the one hand, I call for solid references on biomass gasification and on the other hand, I plead for postponing the availability of these technologies for 2030. Or we can artificially increase the cost of these technologies to prevent models from being too attracted unrealistically to these processes.

Better modelling of this sector would focus on two points. For CCS assets, it would be to model the replacement of capture unit only, instead of considering a total replacement of the production unit. The other would be to model the costs of replacing the electrolysis stacks rather than replacing the entire electrolysis unit. Also, I have only explored the production costs of hydrogen, but other important assumptions need to be appreciated downstream for the storage and distribution of the molecule.

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TIAM V2 Model Update IER - Documentation

Overview of Updates

- Decommissioning Curves for Power Sector
- Renewable Energy Potentials for On- & Offshore Wind, Solar PV, Solar CSP, Biomass, Hydro Power & Geothermal

In depth documentation of Model Improvements

Decommissioning Curves for Power Sector

To estimate the decommissioning curves, the installed capacity in the base year, 2018, was needed. Therefore [IRENA Data](#) was used and summed up for the TIAM regions and all technologies (e.g. Solar PV, Wind On- & Offshore etc.), see Figure 7.

TIAM Regions	2 005	2 006	2 007	2 008	2 009	2 010	2 011	2 012	2 013	2 014	2 015	2 016	2 017	2 018	2 019	2 020	
AFR	23 481	23 486	23 654	23 900	25 939	26 828	26 967	27 626	28 820	28 911	29 436	31 360	34 616	35 990	36 660	37 269	MW
AUS	14 037	14 040	14 048	14 078	14 008	14 014	14 014	14 153	14 165	14 165	14 183	14 183	14 188	14 440	14 455	14 458	MW
CAN	71 978	72 838	73 458	74 407	74 687	75 078	75 573	75 537	75 537	79 420	80 259	80 831	81 004	81 053	81 058		MW
CSA	124 255	127 129	131 003	132 473	134 019	137 411	140 651	142 697	144 950	149 606	153 672	163 753	167 551	172 523	177 766	178 952	MW
CHI	117 390	130 290	148 230	172 604	196 290	216 057	232 980	249 470	280 440	304 860	319 530	332 070	343 775	352 261	358 040	370 160	MW
EEU	23 185	23 216	23 310	23 544	23 664	24 160	24 278	24 597	24 997	24 990	25 241	25 424	25 767	25 877	25 941	26 083	MW
FSU	66 501	66 872	67 894	68 246	69 495	69 885	69 984	72 119	73 436	75 050	75 268	75 530	76 136	76 559	77 652	77 923	MW
IND	34 192	36 681	38 081	39 486	39 548	40 651	42 417	43 035	44 173	45 407	47 103	47 624	49 517	50 060	50 203	50 680	MW
JPN	47 291	47 358	47 313	47 341	47 243	47 736	48 419	48 994	48 932	49 597	50 035	50 117	50 014	50 031	50 008	50 016	MW
MEX	10 598	10 800	11 577	11 433	11 474	11 597	11 571	11 626	11 633	12 464	12 223	12 580	12 642	12 642	12 671	12 671	MW
MEA	22 640	23 689	24 896	25 215	25 982	27 982	29 547	32 610	35 810	38 328	42 577	43 612	44 546	45 711	46 005	48 797	MW
ODA	47 744	48 370	49 968	50 764	54 118	57 693	60 960	66 478	71 292	73 347	77 009	79 897	81 287	85 152	87 379	89 362	MW
SKO	3 883	5 485	5 492	5 505	5 515	5 525	6 418	6 447	6 452	6 467	6 471	6 485	6 489	6 490	6 508	6 506	MW
USA	98 887	99 282	99 771	99 788	100 678	101 023	100 943	101 107	101 589	102 162	102 240	102 692	102 703	102 847	102 769	103 058	MW
WEU	167 331	167 685	169 349	170 538	171 875	172 744	174 368	175 414	176 951	177 245	179 505	182 540	183 706	184 579	185 282	185 984	MW
Global	870 650	894 669	925 760	957 070	991 707	1 025 562	1 056 729	1 089 846	1 136 714	1 175 603	1 211 620	1 246 725	1 272 642	1 295 025	1 311 301	1 331 889	MW

Figure 7: Table for Hydro power generation in all TIAM regions (IRENA, 2020).

Based on the annual production the availability was roughly estimated for all technologies in all TIAM regions, see Figure 8.

Avail %	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
AFR	48%	49%	48%	49%	48%	48%	48%	48%	48%	50%	49%	45%	43%	43%
AUS	33%	34%	33%	29%	31%	33%	36%	31%	35%	36%	32%	35%	35%	35%
CAN	57%	55%	57%	58%	56%	53%	57%	57%	59%	58%	55%	55%	54%	54%
CSA	55%	56%	57%	56%	57%	56%	58%	56%	53%	51%	48%	47%	45%	43%
CHI	39%	38%	37%	39%	36%	38%	34%	40%	37%	40%	40%	41%	40%	40%
EEU	30%	28%	22%	24%	27%	33%	22%	21%	28%	28%	26%	27%	22%	27%
FSU	42%	41%	41%	39%	40%	39%	38%	37%	39%	39%	37%	38%	39%	39%
IND	30%	34%	36%	35%	33%	31%	34%	35%	33%	35%	33%	31%	30%	31%
JPN	21%	23%	20%	20%	20%	22%	22%	20%	20%	21%	19%	21%	21%	20%
MEX	30%	32%	27%	39%	27%	37%	36%	31%	27%	36%	29%	28%	29%	29%
MEA	33%	35%	29%	20%	22%	28%	28%	28%	26%	18%	23%	23%	20%	20%
ODA	39%	41%	40%	41%	38%	40%	40%	40%	40%	39%	36%	39%	42%	41%
SKO	15%	11%	10%	12%	12%	13%	14%	14%	15%	14%	10%	12%	12%	13%
USA	34%	37%	32%	32%	34%	32%	39%	34%	33%	31%	30%	32%	36%	35%
WEU	33%	32%	33%	34%	33%	34%	31%	34%	35%	35%	33%	33%	30%	32%

Figure 8: Example of the availability estimation of hydro power in all TIAM regions (IRENA, 2020).

Based on this data the decommissioning curves are modeled in the ELC-BY-Sheet, see Figure 9.

MAINELEC				-FI-T													
AFR	EFF	RESID	AF	TechName	TechDesc	Comm-IN	Comm-OUT	Region	Units	Sets	AFA	EFF	RESID	RESID-2020	RESID-2030	RESID-2040	RESID-2050
OIL	34%	732.2	0.20	EOILGEN00	EPLT: Exstln ELCOIL	ELC	ELC	AFR			0.20	34%	732.2	732.2	488.1	162.7	0.0
GAS	55%	2774.1	0.44	EQASGEN00	EPLT: Exstln ELCNGA	ELC	ELC	AFR			0.44	55%	2774.1	2774.1	1949.4	616.5	0.0
COAL	39%	2585.3	0.73	EQCOGEN00	EPLT: Exstln ELCDOA	ELC	ELC	AFR			0.73	39%	2585.3	2585.3	1723.6	574.5	0.0
BIO	33%	0.0	0.27	EBIOGEN00	EPLT: Exstln ELCBIO	ELC	ELC	AFR			0.27	33%	0.0	0.0	0.0	0.0	0.0
HYDRO	100%	469.5	0.50	EHYDGEN00	EPLT: Exstln ELCHYD	ELC	ELC	AFR			0.50	100%	469.5	469.5	469.5	469.5	469.5
NUC	33%	126.3	0.74	ENUCGEN00	EPLT: Exstln ELCNUC	ELC	ELC	AFR			0.74	33%	126.3	126.3	84.2	28.1	0.0
GEO	100%	186.7	0.88	EGEOGEN00	EPLT: Exstln ELCGEO	ELC	ELC	AFR			0.88	100%	186.7	186.7	124.5	41.5	0.0
WIN_onshore	100%	30.2	0.28	EWINGEN00	EPLT: Exstln ELCWIN	ELC	ELC	AFR			0.28	100%	30.2	30.2	22.6	7.5	0.0
WIN_offshore	100%	0.0	0.28	EWINGEN11	EPLT: Exstln ELCWIN	ELC	ELC	AFR			0.28	100%	0.0	0.0	0.0	0.0	0.0

Figure 9: Decommissioning curve modeled in the BY-Sheet for ELC. Example of the electricity production in AFR.

As the data is based on 2018, it is estimated, that the installed capacity in 2020 remains the same for all technologies. In 2030 2/3 of the installed capacity is still available while only 1/3 of the installed capacity is available in 2040. In 2050 the technologies of the BY-Sheet are out of stock, except hydro power. For hydro power it is estimated that the capacity remains the same for the whole model horizon, as the lifetime of hydropower is 100 years or even more.

The technologies used for the decommissioning curves start with “E” if the technology is related to energy production, with “CHP” if it is related to CHP plants or with “HET” if they are related to district heat. Furthermore, they all contain “GEN” in the name, so it is possible to filter “*GEN*” for the assessment later on.

The method is applied to all technologies in all TIAM regions.

Renewable Potentials

To estimate the potentials a literature review was done. This review especially included the latest papers on solar pv and onshore wind, as they are mostly used for the renewable energy transition, see Figure 10 and Figure 11.

PV			[GW]					
TIAM Regions	Country Code	Country	TUM	FZJ	Siala2016a	Ruiz2019a	low	high
Africa			149,418.60	61,509.96			10,239.12	149,418.60
Australia			36,586.98	224,475.53			2,630.57	224,475.53
Canada	CAN	Canada	15,852.73	49,944.02			712.68	49,944.02
Central & South America			70,934.37	56,906.74			13,789.04	70,934.37
China	CHN	China	36,774.72	86,051.53			36,774.72	99,067.16
Eastern Europe			1,793.32	117.40		751.00	117.40	56,950.28
Former Soviet Union			107,716.71	63,912.20			1,510.87	107,716.71
Germany	DEU	Germany	283.80	193.49		988.00	193.49	2,032.62
India	IND	India	11,444.06	4,496.45			4,496.45	19,787.95
Japan	JPN	Japan	863.92	3.22			3.22	3,295.99
Mexico	MEX	Mexico	8,743.43	19,148.30			2,429.40	19,148.30
Middle East			30,591.80	56,824.63			6,374.86	56,824.63
Other Developing Asia			33,046.88	9,408.17	3,103.71		3,103.71	1,119,097.07
South Korea	KOR	Korea (the Republic of)	176.30	1.95			1.95	252.23
United States of America	USA	United States of America (the)	34,543.66	63,806.34			27,410.32	63,806.34
Western Europe			8,920.76	2,789.15		6,016.00	2,789.15	140,313.18
Global			547,629.05	699,589.07	3,103.71	7,755.00	236,807.28	2,764,815.74

Figure 10: Literature review on solar pv potential for each TIAM region.

Wind Onshore			[GW]													
TIAM Regions	Country Code	Country	TUM	FZJ	IRENA2019a	Bosch2017a		Chu2020a	Eurek2017a	Bosch2018b	Paul2019a		Ruiz2019a		low	high
						min	max				min	max	min	max		
Africa			149,418.60	13,362.11					4,290.00	4,630.00	601.50	2,767.30			601.50	149,418.60
Australia			37,442.01	41,831.80			21,500.00	27,230.00	29,510.00	7,290.00					776.28	41,831.80
Canada	CAN	Canada	16,862.73	16,141.50			17,780.00	27,800.00	4,960.00						3,672.12	27,800.00
Central & South America			86,787.10	17,693.66			12,830.00	26,500.00	23,620.00						2,782.80	86,787.10
China	CHN	China	36,774.72	21,837.66					19,810.00						19,810.00	36,774.72
Eastern Europe			1,726.35	701.08			1,540.00	19,100.00		16,800.00			537.00	1,117.00	537.00	19,100.00
Former Soviet Union			107,716.71	39,037.65			20,020.00	21,600.00	12,640.00						8,221.08	107,716.71
Germany	DEU	Germany	283.80	294.77											107.00	294.77
India	IND	India	11,444.06	7,031.32			1,020.00	12,600.00					107.00	308.00	1,020.00	12,600.00
Japan	JPN	Japan	863.92	225.82					470.00						225.82	863.92
Mexico	MEX	Mexico	8,743.43	5,802.10					4,230.00						1,207.24	8,743.43
Middle East			30,591.80	9,276.49			24,270.00	24,800.00							569.92	30,591.80
Other Developing Asia			63,638.68	11,421.35											2,872.26	63,638.68
South Korea	KOR	Korea (the Republic of)	176.30	28.90											28.90	176.30
United States of America	USA	United States of America (the)	34,543.66	31,427.98			9,820.00	19,300.00	16,950.00				2,389.00	3,411.00	5,171.68	34,543.66
Western Europe			8,920.76	1,768.42					490.00	630.00					490.00	8,920.76
Global			594,928.61	217,862.49	5,055.00	239,290.00	290,400.00	84,000.00	116,840.00	85,640.00	601.50	2,767.30	3,043.00	3,411.00	47,873.70	927,947.14

Figure 11: Literature review on wind onshore potential for each TIAM region.

The potentials on the remaining technologies were used on the given research. Beside the potentials, the price-potential curve was modeled as well. For the wind onshore 4 technologies were used to model the expansion. It was estimated that 50% of the related area for wind onshore built up can be used without further cost. The next 25% cost roughly 25% more, while the range of 75%-100% cost 150% according to the base scenario, compare Figure 14.

For solar pv it is estimated that the technology is highly scalable and therefore no further cost will occur due to expansion, compare Figure 15.

The technology cost for renewable energies are taken from Pietzcker et al., see Figure 12 and Figure 13.

Techno-economic characteristics of power plants. When efficiency ranges are given, they refer to plants installed from 1970 to 2015, with plants installed after 2010 having the value at the upper end of the range.

	Investment costs (€/kW)	Efficiency (%)	Autocons. (%)	Fixed O&M (%/yr)	Variable O&M (€/MWh)	Min load (%)	Lifetime (yr)
Nuclear	7000	33	5	3	5	40	60
Hard Coal	1800	38–50	8	2	6	30	45
Hard Coal CCS	see Table 2	43	8	2	29	30	45
Lignite	2100	36–47	8	2	9	50	55
Lignite CCS	see Table 2	42	8	2	34	50	55
Gas CC	900	54–60	3	3	4	40	45
Gas CC CCS	see Table 2	52	3	3	18	40	45
Gas CT	400	41	3	3	3	0	45
Oil	400	42	9	4	3	0	40
Hydrogen CC	945	57	3	3	4	40	40
Hydrogen CT	420	39	3	4	3	0	40
Hydrogen FC	see Table 2	45	3	2	3	0	40
Waste	2000	22	2	4	3	0	40
Other gases	900	76	8	3	3	40	40
Biomass	2000	42	5	4	6	0	40
BECCS	see Table 2	42	30	2	6	0	40
Hydro	2500	100	2	2	0	0	80
Wind Onshore	see Table 2	100	0	3	0	0	25
Wind Offshore	see Table 2	100	0	3	0	0	25
PV	see Table 2	100	0	1	0	0	25
CSP	see Table 2	100	0	3	0	0	30

Figure 12: Technology cost taken from (Pietzcker, et al., 2021) (1)

Default assumptions for technologies with time-dependent investment costs (€/kW). Investments costs after 2050 are assumed to remain constant at the 2050 value.

	Hard Coal CCS	Lignite CCS	Gas CC CCS	Hydrogen FC	BECCS	Wind Onshore	Wind Offshore	PV	CSP
2010	3748	3748	2113	2000	3800	1764	4750	2500	6250
2015	3748	3748	2113	1800	3800	1605	4412	1100	5100
2020	3475	3475	1942	1600	3800	1257	2736	703	4750
2025	3200	3200	1800	1400	3625	1197	2419	488	4750
2030	3000	3000	1700	1200	3450	1137	2102	395	4750
2035	2900	2900	1600	1000	3270	1062	2000	357	4600
2040	2800	2800	1550	900	3090	987	1900	340	4450
2045	2700	2700	1500	800	3045	955	1800	332	4000
2050	2600	2600	1450	700	3000	923	1700	326	3560

Figure 13: Technology cost taken from (Pietzcker, et al., 2021) (2)

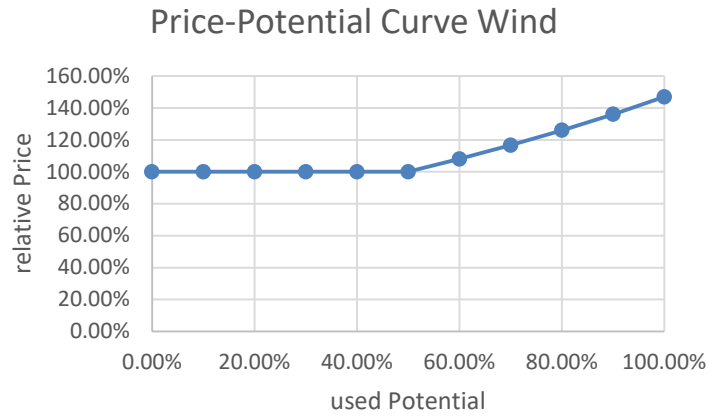


Figure 14: Price-Potential Estimation for Wind.

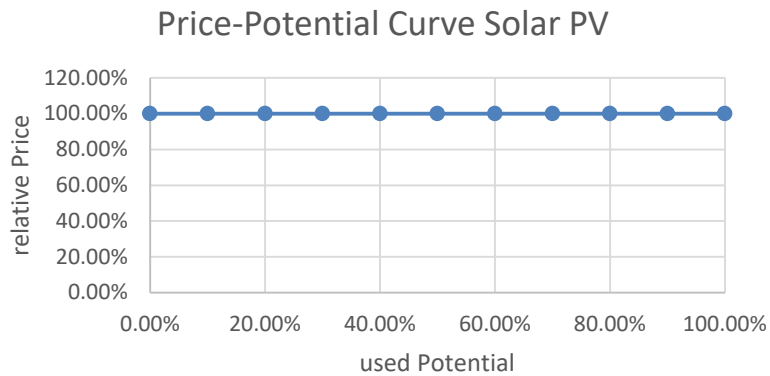


Figure 15: Price-Potential Estimation for Solar PV.

Data availability

All mentioned data (e.g. capacities, availabilities, etc.) is provided.

Literature

IRENA, 2020. *Capacity and Generation Statistics Time Series*, s.l.: s.n.

Pietzcker, R. C., Osorio, S. & Rodrigues, R., 2021. Tightening EU ETS targets in line with the European Green Deal: Impacts on the decarbonization of the EU power sector. *Applied Energy*.

Further developments

1. Based on team discussions during the project realization

Regional disaggregation

At the beginning of this phase, it was planned to change the regional distribution of the model. The previous team worked on this issue and decided to increase the model from 15 to 31 regions. The work was carried out by Maurizio Gargiulo, base-year templates were also calibrated with the 2015 IEA Energy Balances.

Unfortunately, last year, it was decided to remain at 15 regions because of the difficulties of ensuring the rest of the calibration.

It would be interesting to invest resources to make this regional reorganization a success. The lack of data is a major obstacle, particularly as regards trades, but also the time needed to overcome this problem.

Trade representation

The calibration of trades is in itself also a current limitation. The main problem lies in finding data on the inter-regional costs of trade according to resources, but also on the levels of trade and their possible evolution over time.

Demand drivers

At the beginning of the phase, Lucas Desport and James Glynn worked on the update of demand drivers. This is a work they have started to explore with OECD's data and further with IEA World Energy Balance and the IIASA SSP database. This is an ongoing work that could be implemented in the future, but it must be reviewed. What has been proposed in the scenarios ScenDem_IIASA and ScenDem_OECD of the current model works perfectly, although the elasticities of demands to their own drivers can be discussed for other under discussion approach.

NewTech Industry

As also reported by IER (see below), in the current version of ETSAP-TIAM, NewTechs like IND are not activated so far. This leads to massive CO2 emissions, as there are no alternatives. IER can offer technology sheet for IND NewTechs with correct connection of input and output commodities.

2. Based on IER's review

Identified by IER during the review phase and still to be done (the other suggestions have already been incorporated into the model or previously discussed)

- Biofuels emission modelling: Biofuels should have zero emissions
- General CCS Modeling: Several CCS Processes like PUCCSGAS[1-3] are not correctly connected to CO2 Storage. Correct would be CO2forStorage, as defined in SubRES Sequestration
- Decentral Energy ELCD: Decentral (or intermediate ELC) is only available for Hydrogen and Solar PV. Could also be used with Solar CSP with lower DELIV Cost. Furthermore, transformation of ELCD to ELC could be implemented if ELCD is not used for hydrogen production
- Process Heat Industry + UC's: Solar process heat can be implemented to TIAM, especially for the Industry
- Methanol for Transport: Methanol from CO2 and ELC
- Lifetime Wind Off- & Onshore, and for PV: The Lifetime of Wind energy and Solar PV is set to 200 years (see SubRes Trans - MISC) (BS_ELC Lifetime → 200yr)
- Inconsistency of Parameter: There are some inconsistencies of parameter like FLO_EMIS in the ELC basesheet, where the same technology has different levels on CO2 output.
- Population projection of China: Based on the OECD_SSP1 China only has half of its population based on 2018?
- Missing price projections for future: In Scen_Base_Electricity price projections for certain technologies are applied, some are missing. Especially the predefined cases 6-15 are not defined in this worksheet.

3. Based on VTT's review (Notes by Antti Lehtilä)

This brief note summarizes my assorted observations about the new ETSAP-TIAM version circulated among the ETSAP partners. One should note that this review of mine was rather superficial mainly due to limited possibilities of allocating free time for doing a more thorough review. The observations given below may thus also be to some extent just wrong first impressions.

General

The following general notes were made during the review:

- The model version distributed apparently covers the core parts of the original (or previous) version of ETSAP-TIAM well, but some important parts are still missing:
 - Non-CO2 emissions sources and mitigation measures (CH4, N2O, F-gases)
 - Good coverage of alternative fuel production technologies, including P2X
 - Good coverage of negative emissions technologies (e.g. DAC, BECCS, etc.)
 - More extensive coverage of hydrogen fuel chains.

- The import of the model templates into VEDA2 went smoothly, however, the import time was somewhat longer than expected, considering the reduced and "compacted" nature of the current version of the model templates (especially with respect to the compact structure of the Base Templates and the very limited number of scenario files included).
- The model run for the reference scenario also completed smoothly, and revealed that the model generated is actually much larger than the previous version of ETSAP-TIAM.
- Despite the significant increase in model size (by an order of decimal magnitude), the solution time seemed to have increased only roughly linearly with the size increase, which is a notably positive finding: The level of additional detail in the model has not made it quite too heavy to use, which would be good for gaining a sufficient user base for the new version.

Selected Positive Impressions

- The model calibration to 2018 IEA statistics appears to be working, in general, quite well, with only a few dummy imports left in the solution.
- The new timeslice resolution is now four seasons and a representative day with three DAYNITE timeslices under each season, which doubles the number of timeslices compared to the previous version, and seems to be a reasonable compromise between more extensive sub-annual representation and model size. With the current model size (about 5.6 million equations), I would already tend to hesitate adding more timeslices.
- A good attempt has apparently been made for modeling the new wind power, solar power and hydro power capacity potentials in the aggregate model regions, based on quite extensive disaggregated country level estimates, and including impacts on transmission line infrastructure investments.
- The structure of the data specifications in the templates is, in general, reasonable clear.
- The seemingly smooth solution of the reference scenario suggests that there are no major numerical problems in the model, which looks good with respect to further development.

Selected Negative Impressions

Main shortcomings:

- The Baltic States (Estonia, Latvia, Lithuania), which are EU member states, are still included in the FSU region. This is one significant flaw with the current **regional structure**. Assuming that these Baltic States can be rather easily moved out of the FSU, perhaps simply adding them to the EEU region, the two European regions (WEU, EEU) would already much better represent the reasonably coherent EEA region plus Albania and the former Yugoslavia. But some additional enhancements in the regional structure may be considered useful or even necessary by other modelers.
- There are important omissions (e.g. related to non-CO2 emissions, alternative fuels, negative emissions technologies and options, including afforestation, various energy storage technologies, and more detailed hydrogen fuel chains), which may still require considerable further basic modeling work to reach a good level of technology representation for analyzing ambitious climate mitigation scenarios.

Possible other notable issues in the current version:

- The calibration parameters for the RES/COM sectors appear to have mostly the same old values as the old TIAM (based on situation in 2005 or perhaps even 2000), and should be updated. More specifically, the fuel shares appear to be almost fully unchanged, and also some technology shares need updating (e.g. incandescent lighting, missing LEDs, etc.).
- The average capacity utilization of thermal power plants is bounded by fuel type, and mostly quite tightly around statistical values. This seems too restrictive to be reasonable, especially any future CCS plants would be mostly competitive with base-load operation. Instead, defining minimum stable operation levels should be considered for thermal plants.
- It seems that bioenergy and waste-fueled new CHP plants are completely missing (with and without BECCS)?
- Basically all power plants (except CHP) seem to have been defined to have a technical life of 200 years, including wind and solar power. I think this cannot reflect very well the true technical and economic competitiveness of the technologies, even though thermal plants have been defined with O&M costs increasing by operating age.
- Existing CHP processes appear to have somewhat strange CHPR parameters, same for all CHP plants within each region → CHP operation does not correspond to reality. For example, in the WEU region, the process EP_Gas-CHP(2018) has electrical efficiency ACT_EFF= 0.27 and CHPR=0.76, giving a total efficiency of **only 0.48**, and EA_Bio-CHP(2014) has electrical efficiency ACT_EFF= 0.33 and CHPR=0.76, giving a total efficiency of only 0.56. These are far too low for real-world CHP efficiencies. For new CHP technologies, the efficiencies are on a better level, but the use of VDA_CEH=0.2/0.25 together with a fixed NCAP_CHPR makes them rather expensive, because the capacity is then much higher than the true electrical capacity. These apparently misused CEH parameters should thus probably be removed, if fixed NCAP_CHPR is assumed.
- The demand load profiles appear to have only rather rudimentary estimates in the current version. For example, the industrial load profiles are almost identical across all regions, although there are significant differences in the industrial structure. The transport load profiles are likewise all identical for all regions, and the residential commercial load profiles have no other distinction by end-use except for heating (all other end-uses have the same profile). The profiles for different industries and end-uses should be better distinguished.
- Transport vehicle technology characterization seems in some aspects rather conservative, and should probably be fully reassessed with some good sources. For example, efficiencies and learning curves of electric and fuel cell vehicles. In addition, at present, the transport vehicle technologies do not appear to be quite transparently modelled (the capacities do not seem to represent the number of vehicles, and it is also not quite clear what the demands represent, but comparing to other models, it seems they are not representing pkm/tkm). Preferably, both the vehicle-kilometers and passenger/tonne-kilometers should be transparent in the model, as well as the vehicle efficiencies.
- Looks like the impacts of large-scale charging and the related infrastructure needed for electric vehicles may be largely missing in the model, although expected to become notable.

Some Other Minor Issues Observed

- Some demand drivers (population based) appear rather low for a global reference scenario;
- The FLO_SHAR interpolation options for fuel technologies have incorrect process name mask (should include the prefix FT_)
- The model does have some small dummy imports, which should be corrected for.
- The model has some bounds that are very large in absolute values (e.g. -999999999 for many emissions). Such may cause unnecessary additional difficulties for the solver. For example, IBM Cplex warns that placing large bounds on variables can cause difficulty during Presolve, and that large coefficients anywhere in the model cause trouble at various points in the solution process.
- The backstop technologies for emissions are not properly included.
- The data specification is somewhat wasteful for existing power plants (datayears from 1894), with e.g. constant NCAP_FOM values specified for all vintage years.