Core Model Proposal #386: 2023 Hydrogen update

Product: Global Change Analysis Model (GCAM)

Institution: Joint Global Change Research Institute (JGCRI)

Authors: Page Kyle, Jay Fuhrman, Paul Wolfram, Patrick O'Rourke

Reviewers: Matthew Binsted, Sonny Kim

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Purpose: This proposal includes several updates to the hydrogen system and transportation technologies that were performed between June 2022 and June 2023: hydrogen combustion turbines for backup electricity; updated medium and heavy-duty truck costs; charging infrastructure costs for BEV LDVs; nuclear-hydrogen production update; revision to industrial energy use's hydrogen cogeneration technology; hydrogen emissions and fugitive emissions. It is a follow-up to Core Model Proposal 359.

Description of Changes

Overview

The GCAM 6.0 representation of hydrogen technologies has several areas for improvement that were noted in 2022-2023. This proposal addresses a number of such areas, by making modifications to the input data and gcamdata processing code pertaining to the technologies of hydrogen supply and demand, and the electric power sector.

Hydrogen Production Updates

Nuclear-based Hydrogen

The representation of a nuclear-based hydrogen production technology within GCAM has been modified from a nuclear thermal splitting technology to a low-temperature electrolysis route via solid oxide electrolysis. Electrolyzer costs and efficiencies are based on H2A's central production solid oxide electrolysis assumptions version-nov20 (see NREL reference below). Table 1a provides the assumptions for 2015 and 2040. The required nuclear assumptions for the incoming heat and electricity are harmonized with GCAM's electricity sector (Table 1b). For primary energy accounting purposes, the required electricity input is scaled up by a factor of 3 to convert to thermal energy, and added to the reported thermal energy input coefficient, consistent with IPCC convention. Similarly, the thermal energy input coefficient is scaled down by the same factor of 3, and multiplied by the levelized cost for nuclear electricity generation, in order to represent the added cost of potential generation capacity that is bled off to provide steam for process heat.

Table 1a. Solid oxide electrolyzer assumptions for nuclear-based hydrogen production. Values do not include the costs or energy requirements for the production of heat and electricity from a nuclear reactor.

Variable	2015	2040	Units
Non-energy cost	1.7087	0.6878	\$2020/kg H_2
Electricity input/output coefficient	0.13248	0.12636	GJ in /kg H2
Thermal heat input/output coefficient	0.05900	0.04853	GJ in /kg H2

Table 1b. Cost assumptions for nuclear electricity generation

Sector	Subsector	Technology	Year	Capital overnight ($2020/kW)	Fixed charge rate	OM fixed (2020$ / kW-yr)	OM var ($2020 / MWh)	Levelized non-fuel cost of electricity ($2020 / GJ)
electricity	nuclear	Gen_III	2015	6496	0.13	110	2.44	37.41
electricity	nuclear	Gen_III	2040	5974	0.13	106	2.44	32.65

Hydrogen Production via Gas with CCS

While gas SMR is the incumbent gas-based hydrogen production method (typically used for producing hydrogen for feedstock applications, e.g., NH3 production), Autothermal Reforming (ATR) + CCS is thought to be more appropriate for carbon capture and final energy H2 applications. We have therefore updated the gas + CCS hydrogen production technology to ATR + CCS based on H2A "version-aug22" (see NREL reference below). Assumptions for the new technology can be found in Table 2. Given that there were no "future" (or 2040) H2A assumptions for ATR + CCS, we retain the improvement rates from the previous set of assumptions within GCAMv6, which are based on H2A's SMR + CCS production technology.

Table 2. Gas ATR + CCS assumptions for GCAM.

Variable	2015	2040	Units
Non-energy cost	0.71454	0.68918	$2020/kg H_2
Natural Gas input/output coefficient	0.16635	0.16635	GJ in /kg H_2
Electricity input/output coefficient	0.01258	0.01258	GJ in /kg H_2
Water (Consumption and withdrawal) input/output coefficient	8.12	8.12	gal / kg H_2

Updates to Biomass and Coal Gasification Hydrogen Production Technologies

As described in JIRA issue #451, there was an inconsistency in the cost parametrization of the biomass gasification + CCS technology in the electricity sector (based on NREL ATB), and for hydrogen production (based on H2A). If hydrogen were produced via biomass gasification + CCS, and then subsequently used to produce electricity in a hydrogen combined cycle power plant (whose costs and efficiencies are the same as natural gas combined cycle), then the resulting levelized non-fuel costs of electricity would be substantially lower than the corresponding parametrization for a biomass IGCC + CCS power plant, despite being essentially the same process. This contributed to an anomalous result whereby in deep mitigation scenarios, biomass to hydrogen with CCS can briefly become the dominant hydrogen production technology before any constraints on biomass production become binding. Investigation revealed this inconsistency also extended to biomass to H2 (without CCS) as well as coal chemical with and without CCS (corresponding to coal IGCC in the power sector).

To address this, we set a floor on the non-fuel costs of coal and biomass such that the levelized non-fuel cost of generating electricity with the produced hydrogen in a combined cycle power plant (with its assumed cost + efficiency) could be no less than the corresponding IGCC technology in the power sector. Figure 1 reports the resulting upward adjustments in non-fuel costs between the original values based on H2A (dashed lines) and the power sector-harmonized values (solid lines).

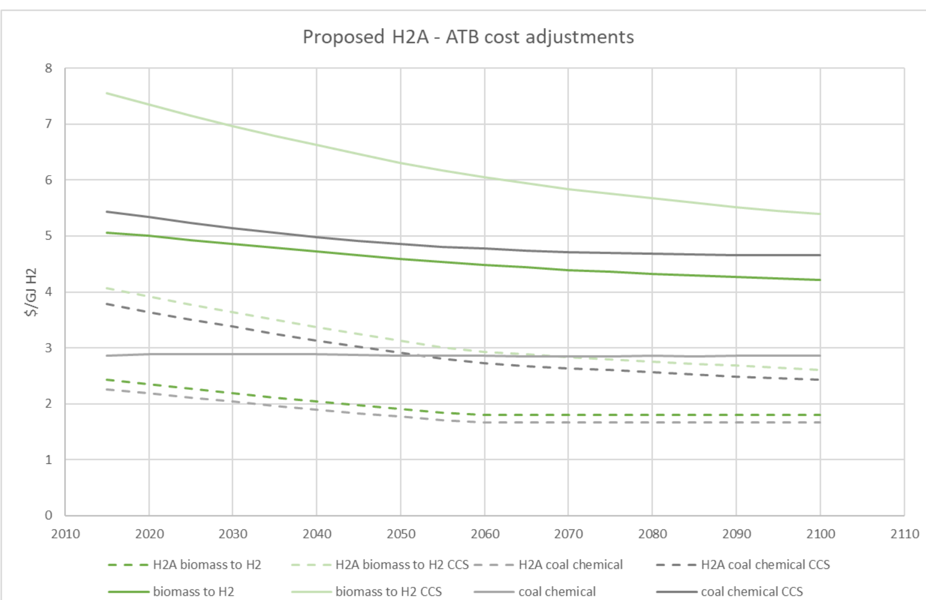

Figure 1. Non-fuel cost adjustments for biomass and coal gasification hydrogen technologies. This proposal updates the assumed coefficients from H2A values (dashed lines) to ATB values (solid lines). Values are presented on a per GJ H_2 basis.

Additional Hydrogen Production Updates: Production Subsector Name Change and CO_2 Capture Fractions

Additionally, this core model proposal modifies a "H2 industrial" sector's subsector name. Previously the subsector which produced hydrogen at the industrial end user was named "forecourt production", and now it is named "onsite production". No changes were made to the technologies represented in this subsector.

Lastly, we adjusted the assumed CO_2 capture fractions to harmonize with those of the power sector, as shown in Table 3.

Table 3. CO_2 capture fractions for hydrogen production.

Sector	Subsector	Technology	GCAM Version	1971	2020	2100
H2 central production	coal	coal chemical CCS	Revised	0.85	0.85	0.95
			Previous (core)	0.91	0.91	0.94
H2 central production	gas	gas ATR CCS	Revised	0.85	0.85	0.95
			Previous (core)	0.91	0.91	0.94
H2 central production	biomass	biomass to H2 CCS	Revised	0.85	0.85	0.95
			Previous (core)	0.91	0.91	0.94

Hydrogen Losses and Fugitive Emissions

GCAM 6.0 does not address hydrogen losses and fugitive emissions. The HDSAM model, upon which the costs and performance characteristics of all hydrogen transmission, distribution, and storage are based (including compression and refrigeration), assumes that 5% of hydrogen will be lost to boil-off in liquid hydrogen truck unloading, but this assumption was not carried through to the GCAM assumptions, and as far as we noticed HDSAM doesn't assume any specific leakage fraction for the pipeline distribution and storage networks. This core model proposal adds hydrogen losses and fugitive emissions for H_2 delivery and refueling stations, using conservative estimates as compared with what is in the literature.

The reasons why this proposal implements non-zero leakages of hydrogen, despite not representing similar losses for other fuels, natural gas in particular, are addressed here. While natural gas fugitive emissions of methane are represented, there isn't any consequent revision to the input-output coefficients, which would require that e.g., 1.01 units of natural gas need to be produced per every unit that enters the pipeline system. This approach reflects the nature of the data and the processing thereof, as well as the characteristics of natural gas production. GCAM's natural gas quantities are estimated from consumption; the reported production volumes in the model are calculated as the sum of consumption, assigned to regions based on production shares. Any upstream losses aren't in GCAM's natural gas production data to begin with. And, because natural gas is naturally occurring, fugitive emissions don't carry an upstream energy or cost footprint. Hydrogen, by contrast, is manufactured, and each unit produced incurs a cost and an energy intensity. Downstream losses (in the T&D system) will contribute to increased end user prices, and will increase the primary energy footprint per unit of hydrogen consumption by an end user. As well, because of hydrogen's physical properties (extremely small molecule, extremely low liquefaction point), it is likely that a significant portion of hydrogen will leak in the transmission, distribution, and storage. While there is significant uncertainty in the literature about what hydrogen fugitive emissions rates are likely to be (shown in Table 4), and no historical inventory data, there is no argument that such emissions might be zero.

Table 4. Estimated hydrogen losses in the literature, by system component. Whole-system estimates provided in studies that didn't disaggregate the components.

		Source			
		Arrigoni & Diaz 2022	Bond et al 2011	van Ruijven et al. 2011	Schultz et al. 2003
Production	Gas SMR	0.0001%	NA	NA	NA
	Electrolysis	0.2%	NA	NA	NA
T&D	Gaseous Pipeline	1%	NA	0.1-5%	NA
	Liquid H2 truck	10%	NA	2-5.5%	NA
	Refueling Station	3% (Gaseous) 8.5% (Liquid H2)	NA	NA	NA
End-Use	On-board storage	NA	NA	0.3-1%	NA
	FC and on-board system	NA	NA	0.1-1%	NA
	Industrial	NA	NA	NA	NA
H2 Economy (production, distribution, use)		1.2-20%	2010: 1-4% 2020: 0.5-4% 2050: 0.1-2% 2100: 0.01-0.5%	0.3-10%	3-10%

This proposal's assumptions are intended to be conservative, not very high, and well within the range of literature estimates (Table 5). It is anticipated that future work will modify these, as the necessary data becomes available. After 2025 we allow for improvement in distribution and refueling loss rates (i.e., a decrease in loss rate) for all relevant technologies other than H_2 refueling stations which have gaseous pipeline delivery (given that their loss rates are already low for refueling, compared to stations with delivery by liquid truck). Values are presented as input/output coefficients (i.e., the value 1.02 implies that 1.02 GJ need to be input to a technology whose output it 1 GJ of hydrogen, meaning there is a 2% loss rate). Fugitive emissions of hydrogen correspond to the equivalent amount of losses incurred (e.g., 2% losses in distribution for a GJ of hydrogen lead to 0.02 GJ of hydrogen being emitted). The whole-hydrogen-economy fugitive emissions loss rates are thus a function of the relative shares of these different pathways, and are addressed in the verification section.

Table 5. Hydrogen losses and fugitive emissions rate. Values are presented as input/output coefficients.

Technology	**2025**	**2050**	**2100**
H2 gaseous pipeline T&D	1.02	1.01	1.007
H2 liquid truck T&D	1.05	1.04	1.02
H2 Refueling station (delivered by pipeline)	1.02	1.02	1.02
H2 Refueling station (delivered by liquid truck)	1.05	1.04	1.02

These technologies are also assigned a corresponding emissions factor of hydrogen (H2) emissions that is calculated from the loss coefficient, assuming an energy content of 120 GJ per tonne of hydrogen. Because the input-output coefficients are exogenous, there is no endogenous control function assumed; emissions factors are assigned in each period as the input-output coefficient minus 1, divided by the energy content. Hydrogen gas emissions are not assigned any global warming potential (GWP), nor are they used to estimate radiative forcing by Hector.

These are topics for future work, not just within GCAM but also in the scientific community more broadly.

Hydrogen Backup Combustion Turbines

Hydrogen is being actively considered as a means of providing long-duration (seasonal) electricity storage. While GCAM does not currently represent seasonal storage, we do have "backup" technologies for renewable electricity technologies (PV and wind) that do not have their own dedicated battery storage. At present the only available backup technology for wind and PV solar (without dedicated battery storage) uses gas. We therefore added a backup technology which utilizes hydrogen to create an alternative to gas. This technology is parameterized as a hydrogen combustion turbine, with the same efficiency assumptions as GCAM's backup gas (steam/CT) technology, but consuming GCAM's "H2 industrial" commodity.

To be conservative with our parametrization of this nascent technology, we apply a 10% capital cost adder, which is consistent with the ReEDS approach, documented on p35 of Ho et al. 2021. The natural gas combustion turbine in the backup_electricity sector is currently assumed to cost $36/kW/yr (1975$). The additional $3.6/kW/yr of the hydrogen technology, assuming a 5% capacity factor, equates to $2.28 / GJ (1975$), $8.707 / GJ (2020$) or 3.1 cents per kWh (2020$; see Table 6).

While fuel cells may also be a viable method of converting seasonally stored hydrogen back to electricity, here we only consider combustion turbines, due to very low capacity factors assumed for the technologies of the backup_electricity sector. The low capacity factors are the reason why combined cycle and/or CCS technologies are not represented within this sector. Nevertheless, future work may determine that fuel cells are an appropriate technology for this application; the net effect would likely be higher non-fuel costs and lower input-output coefficients of hydrogen.

Table 6. Assumptions for GCAM's hydrogen combustion turbine for renewable electricity backup.

Input assumption	2005	2100	Units
Fixed and variable O&M (equal to gas CT)	7.0269	6.4540	$2020/GJ
Additional levelized capital	8.707	8.707	$2020/GJ
Efficiency	0.377	0.428	GJ out / GJ in

This proposal sets nonCO2 emissions coefficients for both gas and hydrogen combustion turbines equivalent to those of gas (steam/CT) in the electricity sector. Note that only NOx and N2O coefficients were parametrized for hydrogen combustion turbines, as the hydrogen fuel contains no sulfur to produce SO2, nor carbon to produce CO, CH4, BC, OC, or NMVOC.

Table 7. NonCO2 emission coefficients of the backup electricity sector technologies, indicated as kg of gas per GJ of fuel input.

Sector	Subsector	Technology	Non-CO_2	Emissions (2015)	Wholesale Gas Input (EJ)	Emissions Coefficient (asterisks indicate the emissions factor is applied to gas CT only)
electricity	gas	gas (steam/CT)	CH4	0.0341419	4.254624	0.00802466 *
electricity	gas	gas (steam/CT)	CO	0.105108		0.02470442 *
electricity	gas	gas (steam/CT)	N2O	0.0098069		0.002305
electricity	gas	gas (steam/CT)	NMVOC	0.00293552		0.00068996 *
electricity	gas	gas (steam/CT)	NOx	0.189189		0.04446668
electricity	gas	gas (steam/CT)	SO2_1	3.77E-04		8.8685E-05 *

Transportation Sector Updates

The transportation data updates are implemented in the file energy/OTAQ_trn_data_EMF37.csv.

Update to Medium and Heavy-Duty Trucks

The transportation assumptions were already revised recently, in Core Model Proposal 359, prior to the GCAM 6.0 release. However, in the 6.0 update, the freight truck characteristics were taken from NREL FASTSim data whose assumptions were from about 2017, and as such didn't reflect the more recent cost estimates of batteries and fuel cells that were used in GCAM 6.0's LDV assumptions. A more recent dataset of vehicle costs was put together by the Autonomie/BEAN modeling teams at Argonne National Laboratory (Islam et al. 2022), published in October 2022. In this revision, we adopt their assumptions for medium and heavy-duty trucks. Specifically, for the USA region we adopt exactly their assumptions of vehicle energy intensities and capital costs for the following vehicles:

Table 8. Mapping between GCAM and Autonomie truck size classes

gcamdata size class	DOT size class	Autonomie vehicle
Truck (2.7-4.5t)	Class 2	Class 2 Van
Truck (4.5-12t)	Classes 3-6	Class 6 Box Truck
Truck (>12t)	Classes 7-8	Class 8 Longhaul Sleeper

And for the following technologies, shown in Table 9:

Table 9. Mapping between GCAM and Autonomie truck drivetrain technologies

Autonomie technology	gcamdata technology
Conv	Liquids
BEV	BEV
FCHEV	FCEV

The reason why the Autonomie FCHEV technology is used rather than the Autonomie FCEV technology is that the former is more cost-effective for all size classes analyzed. The difference is that the FCHEV has its fuel cells sized to the maximum steady load, whereas FCEV's fuel cells are sized to the maximum instantaneous load; as such, the FCEV vehicle has more fuel cells, less batteries, and for all of the vehicles analyzed was always more expensive. Given that both are 100% powered by hydrogen and both are assumed equally effective at delivering freight transportation service, we represent only the one that is less expensive.

GCAM's Hybrid Liquids technology, which is intended to be a higher-cost and higher-efficiency version of the Liquids technology, doesn't have an analogue in Autonomie. Here we simply assign the technology 7% higher capital costs and 7% lower energy intensity than the corresponding Liquids technology in each size class. The constant factor, 7%, was calculated from the GCAM 6.0 assumptions, and here is held constant over time.

The biggest change in the revision here is for heavy duty BEV trucks, whose assumed capital costs decreased from about $500,000 in 2030 to about $260,000. This change reflects the updated battery costs, which in 2017 were significantly higher, and were expected to remain that way for longer than was observed in the real world.

For O&M costs of medium and heavy-duty trucks, we use the same FASTSim estimates as before, as these costs have likely been stable over time, and because these costs are scenario-specific and difficult to systematically extract from the Autonomie/BEAN model data. However, two errors were noticed in the data processed from FASTSim that are corrected here. First, the assumptions from FASTSim were provided in $/mi, and were not converted to $/km for GCAM. Second, where in FASTSim all drivetrains are assigned the same O&M costs except for BEVs, which are assigned lower costs, these lower costs had also been assigned to FCEV trucks in the GCAM assumptions. Together these errors had the effect of making the BEV and FCEV technologies less expensive than intended, which wasn't really a problem in the GCAM 6.0 assumptions because this set of assumptions also had high capital costs for these vehicles. Note that these O&M cost revisions to the medium and heavy-duty size classes are also reflected in revised costs for the light truck size class, as the latter are computed from the former. While generally the light truck size classes in the freight sector inherits their characteristics from the corresponding vehicles in the passenger sector, the O&M costs do differ between the uses; for example, in the freight+commercial sector these costs include the cost of the driver.

Non-USA truck costs and energy intensities were also revised in all non-US regions, following the same method as in Proposal 359: cost and efficiency multipliers from "Liquids" to all other technologies are computed from the USA data, and applied to the assumptions of the Liquids trucks in all non-US regions. That is, the BEV/ICEV and FCEV/ICEV non-fuel cost ratios are the same in all regions in any given year and truck size class, irrespective of the base ICEV truck cost.

This proposal also revises the load factors of Heavy trucks in the USA, as well as BEV trucks in all regions, in order to better reflect the on-road observed freight averages in the USA, and in order to account for the payload reduction from the extra mass of BEV vehicles, respectively. The GCAM 6.0 and prior assumptions had quite low average load factors for Heavy trucks; across the Medium and Heavy trucks (i.e., Classes 3-8), the net average load factor was 3.05 tonnes per vehicle. GCAM's Heavy truck size class (i.e., classes 7-8, gross vehicle weight from 12t to 36t) was assigned a load factor of only 4.16t. According to statistics from the Bureau of Transportation Statistics (tonne-km of goods transported) and the Transportation Energy Data Book (vehicle-miles), the average load factor for Classes 3-8 should be about 6.5 tonnes per vehicle. This proposal revises the load factors of the heaviest truck size class; the revised assumptions for both the Class 3-6 and Class 7-8 trucks are set to 71% of the corresponding assumptions in Autonomie, shown in Table 10.

Table 10. Revision to load factors of trucks in the USA region, for the size classes where a revision is performed.

gcamdata size class	DOT size class	Prior assumption	Revised assumption
Truck (4.5-12t)	Classes 3-6	3.6 tonnes	3.6 tonnes (no change)
Truck (>12t)	Classes 7-8	4.16 tonnes	12.26 tonnes

We do not use the exact Autonomie assumptions for the representative vehicles because they are pretty close to the legal limits (GVWR = gross vehicle weight rating), which aren't representative of on-road averages due to empty and partially loaded trips. The net result is that in the base year (2015), for this proposal, the net average load factor of Class 3-8 trucks in the USA increases from 3.05 tonnes in the core model to 6.69 tonnes in the revision. This is reasonably close to the 6.5 tonnes that can be calculated from the BTS and TEDB data for the year 2015.

This proposal also reduces the load factors of BEV medium and heavy trucks in all regions in order to account for the additional mass of BEVs as compared with all other drivetrains, due mostly to the mass of the battery packs. The net vehicle "curb weight" (i.e., the empty vehicle with a full fuel tank) is an output of Autonomie, and considers the mass of each component of the drivetrain and auxiliary equipment that varies between the vehicle types. While Autonomie does not reduce the assumed cargo/payload of BEVs, the documentation acknowledges that such a reduction would be reasonable; instead, the Autonomie approach is to set the cargo assumptions such that all vehicles, including the BEVs, would be within the maximum legal limits (GVWR). This allows an apples-to-apples comparison between the various drivetrains. What we want in GCAM is a realistic approximation of how the additional mass of BEV trucks would impact the average observed load factors in real-world applications. For vehicles like gravel trucks and cement mixers that are typically loaded to the maximum limit, each additional tonne of BEV mass reduces the payload by one tonne, but the empty vehicle return trip (which also contributes to the assumed average load factor) wouldn't be impacted, nor would most partially laden trips.

The approach for estimating the reduced average load factor of BEVs is to first develop time-dependent linear functions that estimate the extra mass of the BEV as a function of the assumed payload of the corresponding liquid fuel truck (from the Autonomie results). The additional vehicle mass that is due to BEV decreases over time due to the assumed future improvements in battery technologies that improve the energy density of batteries. and then to divide the slope by 2, so that each additional extra tonne of battery mass only reduces the average load factor by 500 kg. This exercise is performed for the base year (2021 in Autonomie) and the 2050 time period, with the in-between years' assumptions interpolated linearly. The change over time reflects expected improvements in battery energy density. These linear functions, shown in the Figure 2, are then applied to the GCAM assumptions for load factors, which again are already de-rated from the specific Autonomie assumptions in order to reflect empty and partial-loading trips. The assumptions in this proposal are estimated from the 50% linear series in the plots below, with no modifications to load factors for trucks whose load factors in any given year are at the point where BEV additional mass is zero or less. In the charts, the Autonomie series show the additional mass of the BEV trucks as compared with the corresponding Conventional truck, for the three size classes used (Class 2 Van, Class 6 Box Truck, Class 8 Longhaul Sleeper).

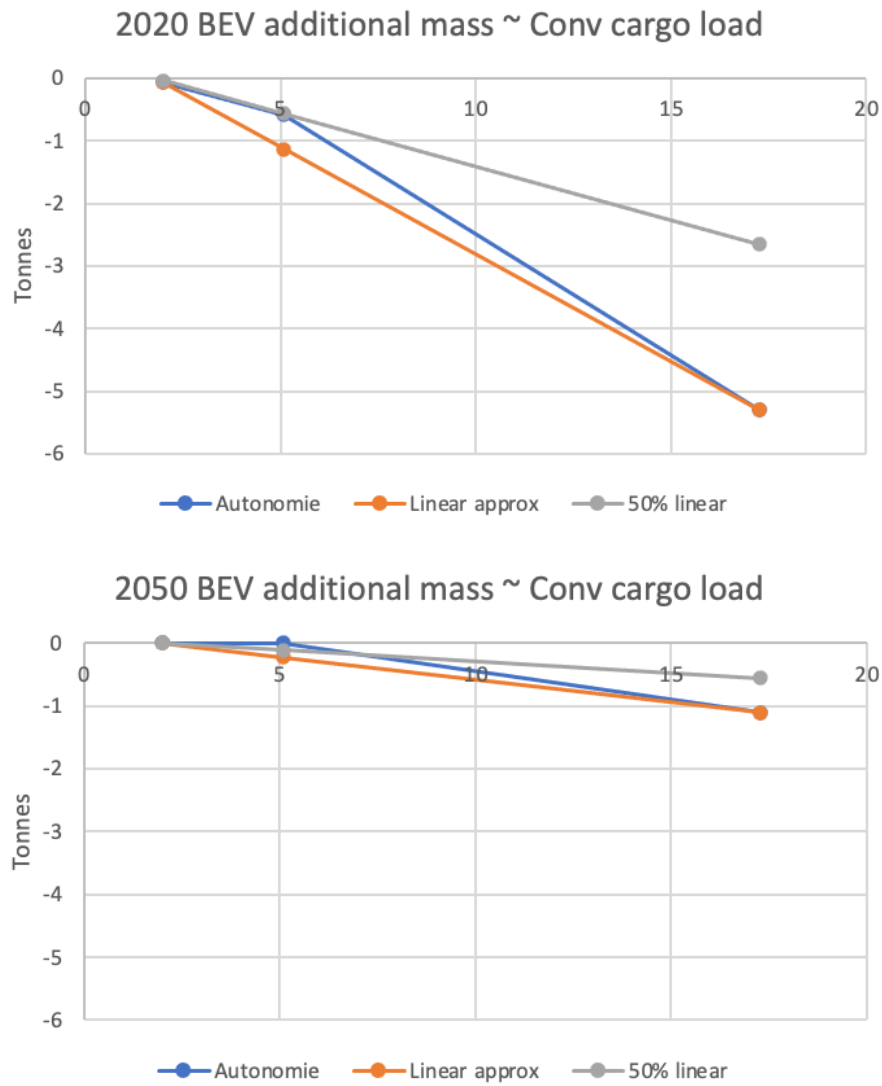

Figure 2. BEV truck additional mass vs. conventional truck, in the 2020 (left panel) and 2050 (right panel) time periods. The difference between the two panels reflects assumed improvements in battery power density over time. The 50% linear series is the difference in assumed load factors in the GCAM assumptions in this proposal.

The net result for the USA region is depicted in Figure 2, and GCAM's BEV load factors are adjusted as shown in Table 11.

Table 11. Revision to GCAM BEV truck load factors

gcamdata size class	Base_LF	BEV reduction (2020)	BEV LF (2020)	BEV reduction (2050)	BEV LF (2050)
Truck (2.7-4.5t)	1.01	0	1.01	0	1.01
Truck (4.5-12t)	3.6	0.31	3.29	0.06	3.54
Truck (>12t)	12.26	1.79	10.47	0.37	11.89

So, in the 2020 time period, the Classes 3-6 trucks have their load factors derated by 9%, and the Class 7-8 trucks are derated by 15%. These reductions are 2% and 3% by 2050, respectively. These reduced load factors feed directly into the cost competition between battery electric and other modes of freight. These reductions are applied to all non-US regions following the same method.

Update to BEV Charging Costs (LDV and M/HDV)

The cost of BEV charging infrastructure has also been revised in this core model proposal based on updated data from Autonomie. Table 12 provides the updated GCAM capital costs for charging infrastructure. Note that this approach of assigning infrastructure-related costs to the vehicle technologies themselves differs from the other fuels, whose infrastructure costs are captured in the prices of the delivered commodities (e.g., "refined liquids enduse" costs include the costs of fuel distribution and the operation of service stations, as do "H2 retail dispensing"). With electricity, "elect_td_trn" costs only include the costs of electricity delivered to the facilities from which transportation vehicles are powered, so any vehicle-specific charging costs would either require new pass-through sectors (e.g., elect_td_truck, elect_td_car, elect_td_rail, and so on), or for such costs to be added to the vehicle costs. This proposal adds the charging equipment costs to the vehicle costs; they are disaggregated in the inputs to gcamdata, but not in the model input XML files or the output data.

Table 12. BEV charging infrastructure costs. For LDVs these costs reflect the installation costs of home charging systems, and for medium and heavy duty trucks the costs reflect the average levelized non-electricity costs of charging station construction, operations, and maintenance. These data were provided by the Autonomie/BEAN team at Argonne National Laboratory, and are not published with the public Autonomie/BEAN cost data on the levelized costs of driving.

BEV type	Unit	Previous cost	Updated Cost (2030)
Light-duty vehicle (LDV)	2020$ per car	$1302	$1834
Medium truck (Classes 2-6)	2020$/kwh	0	$0.14
Heavy truck (Classes 7-8)	2020$/kwh	0	$0.055

Note that infrastructure costs are not assigned to FCEVs in GCAM. This is because the non-energy costs and energy requirements for hydrogen dispensing / refueling are modeled within GCAM's "H2 wholesale dispensing" sector. For more information on GCAM's assumptions for hydrogen refueling, please see https://jgcri.github.io/gcam-doc/cmp/359-Hydrogen_and_transportation.pdf.

Hybrid Liquid Truck non-CO2 Emissions Mapping

Mapping lines have been added for hybrid liquid truck non-CO2 emissions (see UCD_techs_emissions_revised.csv).

Bus Load Factor Change

Load factors are revised downward in this core model proposal for all buses in Africa, India, and South East Asia. Previously the load factors were assumed to be 47.4878 persons/vehicle (defined within UCD_trn_data_CORE.csv). While this assumption had a basis in the literature, and is reasonable for large inter-city buses in these regions, it was inconsistent with the assumed energy intensities which were parametrized based on smaller buses, and as such the resulting energy intensity per passenger-km was too low. This proposal divides the load factors by 2 in order to return better estimates of passenger service intensity, which for these regions are probably around 0.15-0.2 MJ/pkm.

Domestic Shipping Cost Change

Domestic ship 'CAPEX and non-fuel OPEX' values for 2025 were applied to historical years for the BEV technologies (for consistency). As these technologies' share-weights were zero in these years, this doesn't influence model outputs, but if model users were to revise the share-weights to allow BEV ships in 2025, the costs would now be correct to what is intended.

Industrial Sector Updates

Revision to Industrial Energy / Cogen Technology

The 'other industrial energy use' sector's hydrogen cogeneration technology has been modified for consistency with the other cogeneration technologies within industrial energy use, which are generally parameterized as technologies with a power-to-heat ratio of about 0.4 (that is, about 0.4 units of electricity produced per unit of useful thermal energy, usually in the form of steam). The hydrogen cogeneration technology had been assigned a power:heat ratio of greater than 1, so it was more of a power generation technology than a technology of industrial energy use. This Revision modifies assumptions to make the technology more similar to the sector's gas cogeneration technology (i.e., hydrogen combustion with CHP). First, the technology's share weight was modified from "1" to "0.15" (roughly similar to the gas cogeneration technology share weight across GCAM regions). The assumed CHP electricity output per unit of fuel input was also reduced from 0.5 to 0.25 (the latter is equivalent to gas cogeneration’s value). Lastly, the technology's efficiency was set equal to the gas cogeneration technology's value (e.g., 0.612 in 2020, rising to 0.63 in 2050).

Stationary Off-road Industrial Sector: input and share-weight revision

Stationary technologies in the agricultural, mining, and construction energy use sectors have had their energy input revised to "H2 wholesale delivery" (rather than "H2 retail delivery"). While these sectors are geographically distributed, which would argue for the higher delivered fuel rates, they are part of the industrial sector both in GCAM and in the energy statistics, and as such are assigned industrial rate classes on all other fuels (e.g., refined liquids industrial, wholesale gas, elect_td_ind). This also aligns the stationary hydrogen technologies the off-road industrial mobile applications in these sectors, which consume "H2 wholesale dispensing". The change therefore reduces the input cost for hydrogen for these stationary technologies. No numerical change was made to the efficiency assumptions for hydrogen.

The core version of GCAM also had hydrogen technology share-weights in the stationary off-road industrial sectors fixed at their final calibration values (zero in 2015), which had the impact of ensuring that stationary off-road hydrogen technologies never got any market share. Here we revise the interpolation rule such that these technologies linearly interpolate from zero in the base year (2015) to 0.05 in 2050 for all three non-manufacturing sectors. This low value is consistent with the natural gas share-weights seen in the USA in these industries; these industries tend to have low preference for natural gas, even when gas is generally available throughout the energy economy.

GCAM-USA Revisions

The GCAM-USA module is modified to allow hydrogen combustion turbines in the backup_electricity sector. The backup_electricity sector of GCAM-USA is contained within the GCAM regions, i.e., not at the state or grid region level, and this proposal does not modify that. Instead, this proposal creates a "H2 industrial" commodity within the USA region which is composed from technology competition between the 51 states' H2 industrial sectors, and this "USA H2 industrial" is the input to the backup_electricity sector in the USA region. The state-level share-weights of "USA H2 industrial" are set equal to the population shares of each state. As such, the total national quantity of H2 backup combustion turbines (capacity and generation) are computed at the national level, and this national total is shared out to the states on the basis of the share-weights (population shares) and the relative costs.

Validation

Despite the number of changes to data in this proposal, the net impact on most high-level results is quite modest. While revisions such as lower-cost battery electric trucks and hydrogen combustion turbines in the backup_electricity sector tend to facilitate emissions mitigation, closing the hydrogen-BECCS loophole has the opposite impact. Figure 3 shows the CO2 price trajectories in the mitigation scenarios; in all cases, the Revision scenarios (dotted lines) see a modest reduction in prices, between 1.3% (SSP1) and 4.1% (REF).

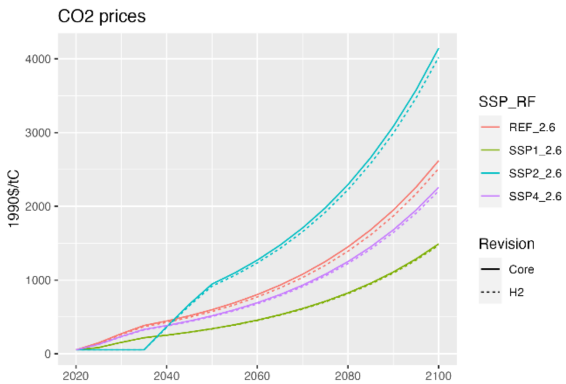

Figure 3. CO2 prices (1990$/tC) in the 2.6 scenarios, comparing the Core model to the H2 Revision.

Figure 4 shows the net impacts on primary energy across the full scenario set, and in the year 2100 by fuel.

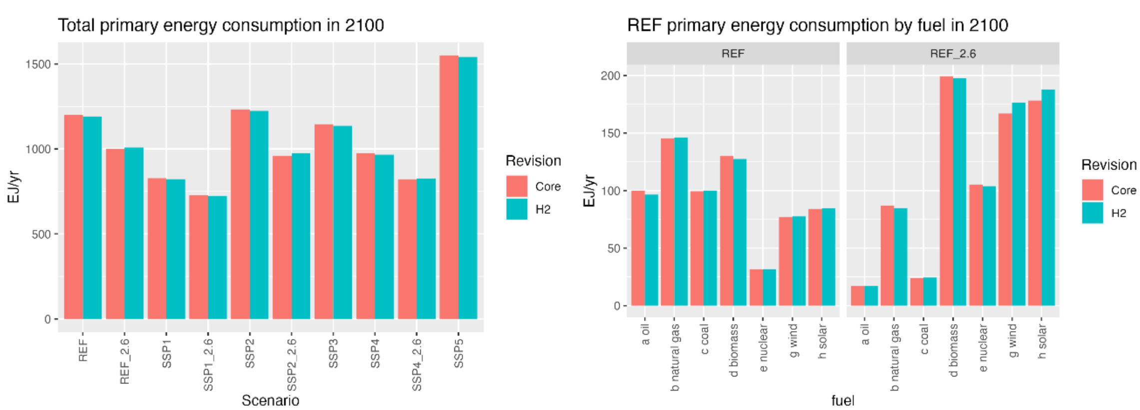

Figure 4. Total primary energy consumption in 2100 (left panel), and primary energy by fuel in 2100 in the REF (i.e., "GCAM") and REF_2.6 ("GCAM_2p6") scenarios (right panel). Both panels highlight pairwise differences between the Core (ref) and H2 Revision (blue).

There is only modest impact on total primary energy (typically about 1% difference), and the direction of the effect is scenario dependent. Within fuels, the largest changes seen are increases in wind and solar, complemented by minor reductions in natural gas, biomass, and nuclear. The increases in wind and solar reflect the removal of low-cost hydrogen BECCS (shifts hydrogen production shares more towards wind and solar which compete with BECCS), and the allowance of hydrogen to provide backup_electricity (reduces demand for natural gas, increases demand for hydrogen, decreases costs of backup_electricity which increases market shares of intermittent renewables). The remainder of the figures focus on variables within the scenarios that are directly impacted by the changes in the proposal. As shown in Figure 5, all scenarios in the H2 Revision see modest increases in total hydrogen production, and at the technology level, the Revision sees the following expected changes: less BECCS, less nuclear, and less coal. Because the total market demand is increased (analyzed with Figure 6 below), the H2 Revision scenarios see increases in electrolysis from wind, solar, and grid electricity.

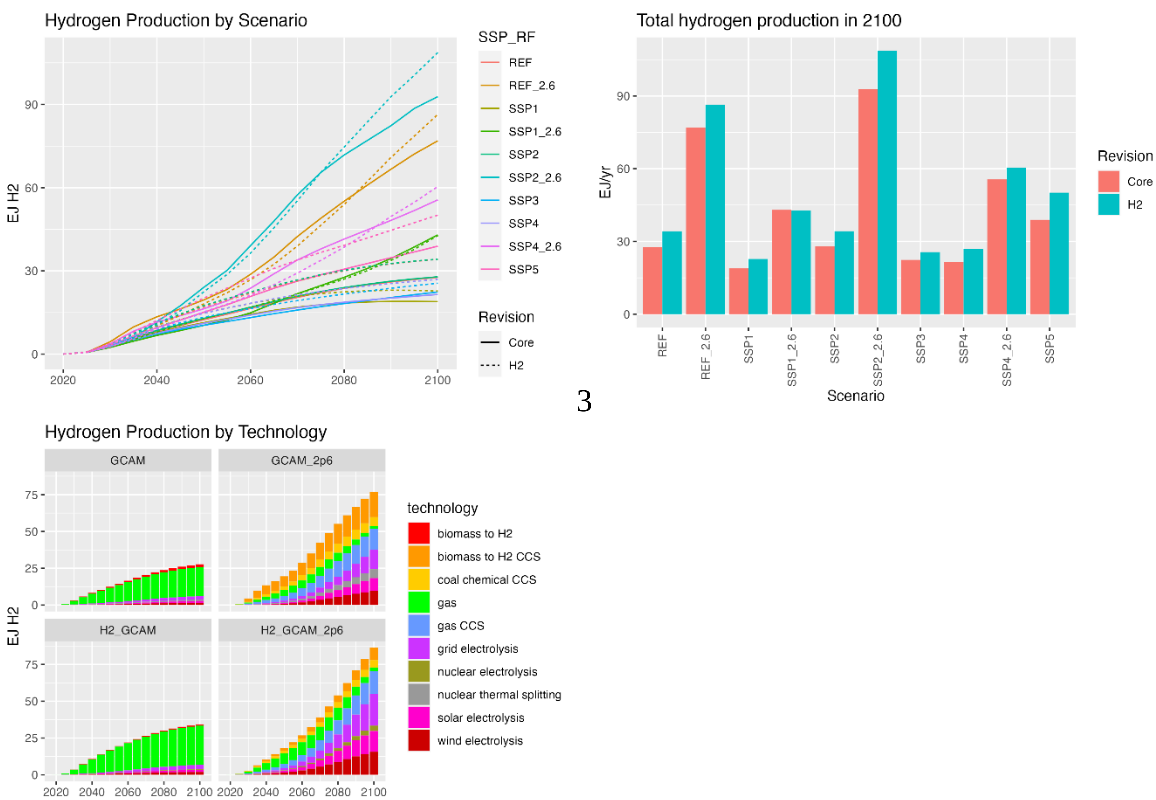

Figure 5. Total hydrogen production by scenario (left panel), with a focus on 2100 (center panel), and hydrogen production by technology (right panel), comparing the reference scenarios between the core model (GCAM, GCAM_2p6) and the H2 Revision (H2_GCAM, H2_GCAM_2p6), respectively.

As Figure 6 shows, the demands of hydrogen are quite similar between scenarios, as is the choice between transmission and distribution technologies (i.e., the competition between pipelines, trucks, and on-site production). The main differences between the scenarios are that the H2 Revision scenarios have hydrogen combustion turbines which increases the total market demand for the 2p6 scenarios, and the freight sector's demands increase in response to the changes to the transportation road freight technologies. Another factor that drives the comparative increase in production, though not demand, is the modeling of losses, analyzed in Figure 7.

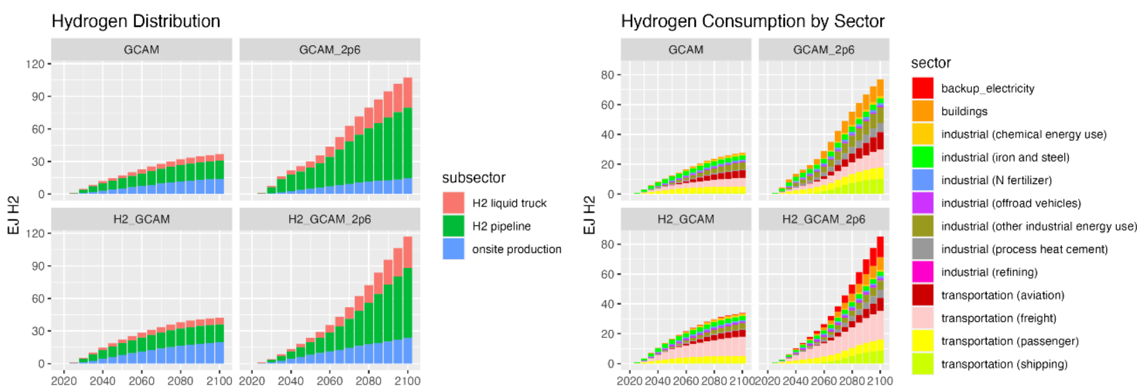

Figure 6. Hydrogen distribution by technology over time in the reference scenarios (left panel), and hydrogen consumption by end-user group (right panel), for the reference scenarios with and without the H2 Revision.

Figure 7 shows that aggregated across all of the distribution technologies, about 3% of hydrogen produced is lost as fugitive emissions in the early years, which decreases over time to between 1% and 2% by 2100. The key factors determining system-wide leakage rates are the degree to which hydrogen is liquefied for transport via trucks, and the degree to which production takes place on-site. Liquefaction and transferal from one vessel to another entails significant boil-off losses, even using the conservative assumptions shown in Table 5, and on-site production is not assigned any leakage. Note that these system-wide leakage rates are within the bounds but at the lower end of what is thought to be likely in the literature, and the values will likely be revised in upcoming years as more data become available from the industrial and scientific communities.

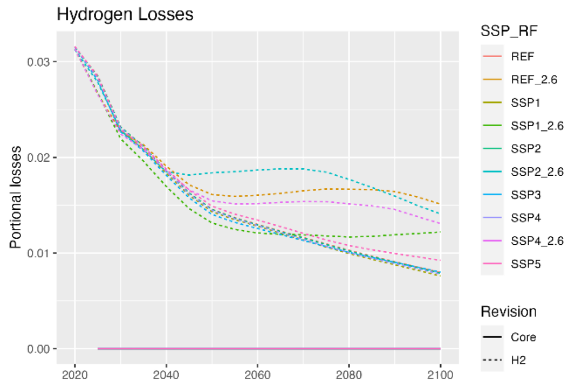

Figure 7. Hydrogen losses by scenario, calculated as the difference between total hydrogen production and total hydrogen demand, divided by total hydrogen production. On-site production is included in both the numerator and denominator of the calculation.

The remainder of the validation section addresses the end-use consumption sectors that were directly impacted by the changes in the proposal. Industrial cogeneration is a bit lower in the no-mitigation scenarios, but in the mitigation scenarios sees a dramatic departure (left panel of Figure 8), which is explained in the right panel of Figure 8. In the Core scenarios, the hydrogen cogeneration technology is functioning as a circuitous method of producing electricity with BECCS, by first producing hydrogen with BECCS, and then generating electricity in the industrial sector. This proposal shuts down both mechanisms of this artifact, by increasing the costs of hydrogen with BECCS and reducing the power-to-heat ratio of hydrogen industrial cogeneration.

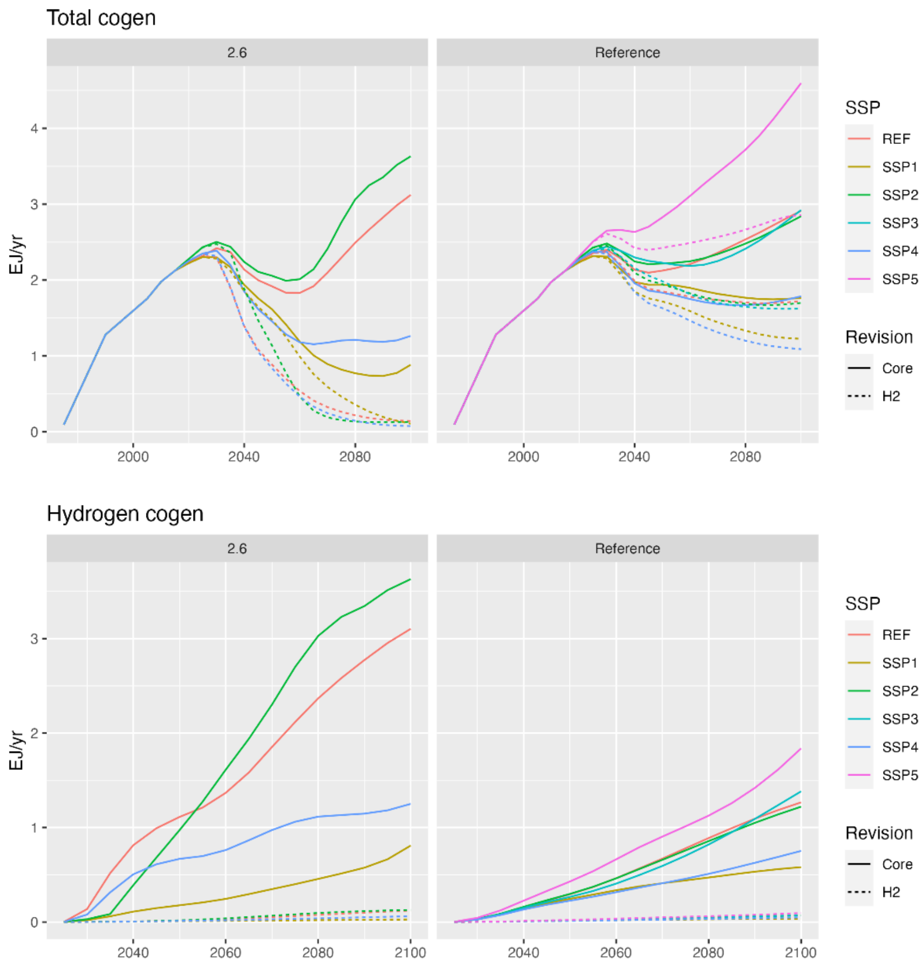

Figure 8. Total cogeneration by scenario (left panel), distinguishing reference from mitigation (2.6) scenarios, and hydrogen cogeneration (right panel).

In the non-manufacturing sectors, the inclusion of hydrogen as a stationary fuel option has a modest impact on results, shown in Figure 9. The highest shares of hydrogen use are seen in the mining industry which was the one that had the highest use of gaseous fuels in the base year. In general, the main mitigation option of these industries remains electrification, though the competitive balance between electricity and hydrogen is shifted somewhat. To close, we note that due to the capability for on-site transformation between electricity and hydrogen in the industrial sector in general, and the fact that the energy modeling and statistics communities haven't yet defined best practices for the delineation of "final" energy in cases where such transformations are occurring between these two fuels whose consumption is normally considered final, there is an unclear boundary between these two fuels in this sector.

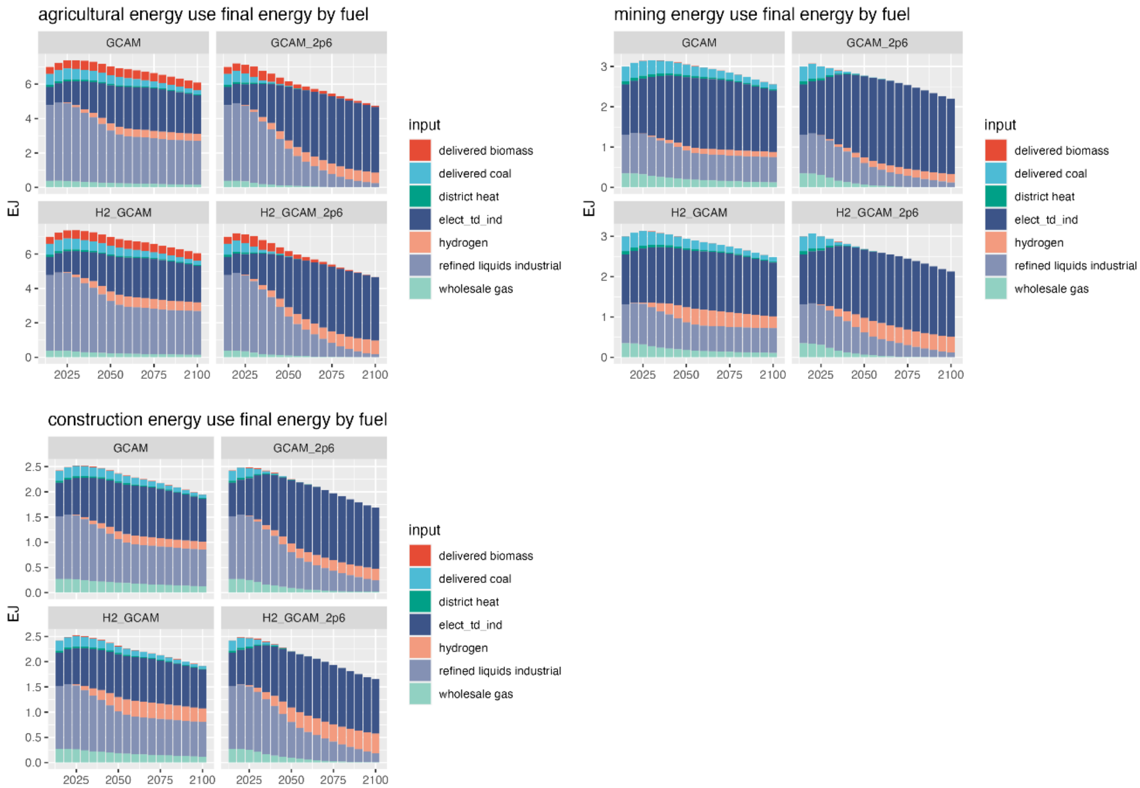

Figure 9. Energy use in the agriculture, construction, and mining industries, in the Reference ("GCAM") and Reference 2.6 ("GCAM_2p6") scenarios, before and after the H2 Revision.

Moving to the electric power sector, Figure 10 shows the backup capacity by scenario in the USA region. While the total backup capacity is reasonably similar between the scenarios, the H2_GCAM_2.6 scenario has slightly more total backup electricity capacity over time, and hydrogen accounts for the majority of the market share towards the end of the century. In this way, the Revision scenarios allow for a "backstop" technology within this market segment that has been required to produce fossil-based emissions in order to provide the necessary backup capacity for intermittent renewable electricity generation.

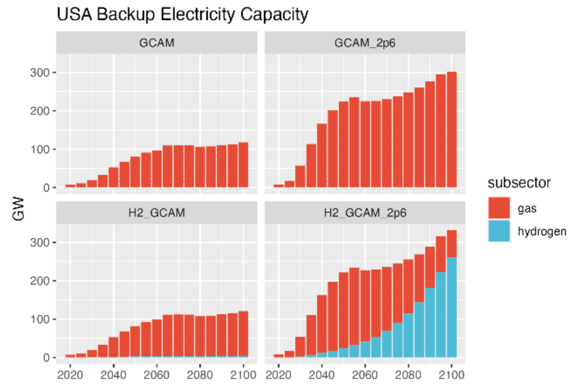

Figure 10. USA backup_electricity capacity by technology, calculated from the reported energy using a capacity factor of 5%.

The next figure, Figure 11, examines how the "H2 industrial" commodity is used by the whole USA region (i.e., all 51 states plus the USA region itself), in the four main analysis scenarios.

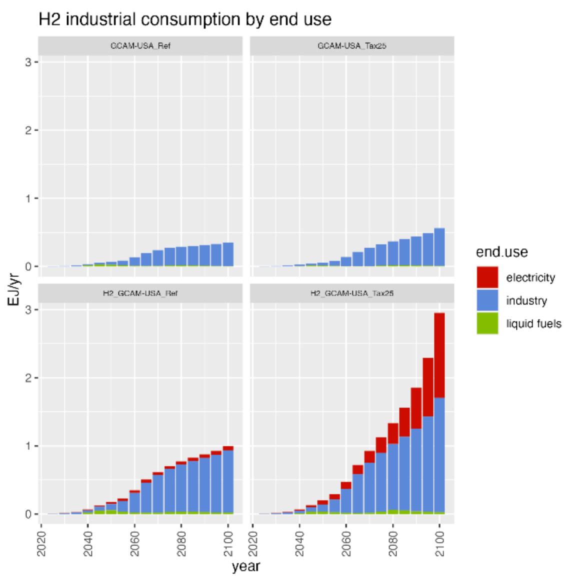

Figure 11. H2 industrial consumption by scenario and sector: backup electricity generation, industry, and liquid fuels.

The change in hydrogen use in the industrial sector is due to the revisions related to cogeneration, both in the share-weights and the secondary output ratios, which together shift how hydrogen is used in the industrial sector, from (primarily) a source of on-site power generation to a source of industrial heat. The net change in the results suggest that in the model, hydrogen is more valuable for industrial heat than for industrial power production. The H2_GCAM-

USA_Tax25 scenario demonstrates that by the end of the century, backup electricity is one of the major energy and industrial sector uses of hydrogen. In terms of consistency with the USA region in the standard configuration, Table 13 shows the H2 industrial (i.e., hydrogen consumption excluding transportation and buildings) demands of hydrogen in the year 2100, by scenario.

Table 13. Hydrogen consumption in the USA region by the electricity and industrial sectors in 2100 for selected scenarios.

Scenario	Revision	USA	GCAM-USA
Reference	Core	0.63	0.35
Reference	H2	0.68	1.00
Policy	Core	1.49	0.56
Policy	H2	1.92	2.95

Figure 12 demonstrates the modeled outcomes for service output in the transportation sector globally (i.e., all 32 regions added up, in the standard configuration), focusing on aviation, shipping, passenger light-duty vehicles, and freight trucks. Within each mode, the left-hand plots are the reference scenario and the right-hand plots are the Ref_2.6 scenario, while the upper are the core model and the lower are this proposal. As expected, the model output for aviation, ship, and LDV are about the same as before. The revisions in trucks lead to more BEVs and FCEVs in both the reference and the policy scenarios, particularly FCEVs. The Ref_2.6 scenario actually sees a near-100% phaseout of Liquid fueled trucks by 2100.

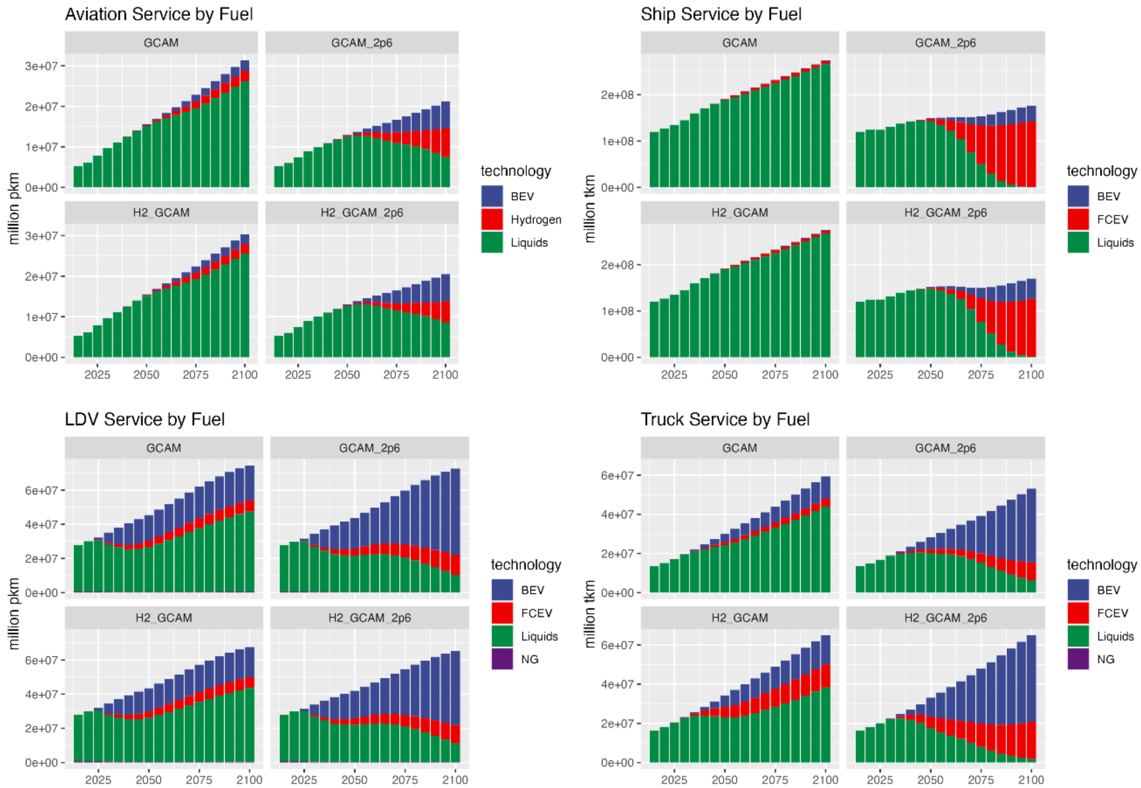

Figure 12. Transportation sector service output by selected modes in GCAM-USA.

The differences in behavior in the heavy-duty trucking sector are explored further in Figure 13, which shows the levelized service prices in selected years for the available drivetrain technologies within the "Car" segment of LDVs and the "Heavy truck" segment of M/HDVs, in the USA region (32-region configuration). Note that the LDV and M/HDV market segments all have the same logit exponent (-8) governing the vehicle drivetrain choice. In the LDV segment, the levelized costs of service provision are reasonably similar between BEV and the two liquids technologies (Liquids and Hybrid Liquids), with FCEVs being a bit more expensive. In the policy and towards the end of the century (2090 shown), the BEVs gain a ~20% cost advantage over the liquids technologies, which is responsible for their dominant market share, but not enough to induce an effective phase-out of liquids technologies. In the heavy truck segment, where fuel costs account for a larger share of the total service costs, the increase in total costs in going from reference to policy and from 2035 to 2090 is more pronounced for the liquids technologies, both in the core model and the H2 revision. In the core model, the BEV technologies are 20% less expensive than Liquids in 2090, and FCEVs are about 10% less expensive, resulting in similar market share outcomes for the LDV and Truck market segments (Figure 12). With the revised costs of all technologies in this proposal, the BEV technology has a 35% cost advantage over the Liquids and Hybrid Liquids technologies, and the FCEVs have a 30% cost advantage. Note that these relative cost differences between the drivetrain technologies are unrelated to the updated load factors. While the large absolute cost differences between current core and the changes in this proposal (H2) for the Heavy truck size class (right panel of Figure 13) are due to updated load factors, the differences in relative costs, and therefore competitiveness, between drivetrains are driven by different assumptions about capital costs and energy intensities.

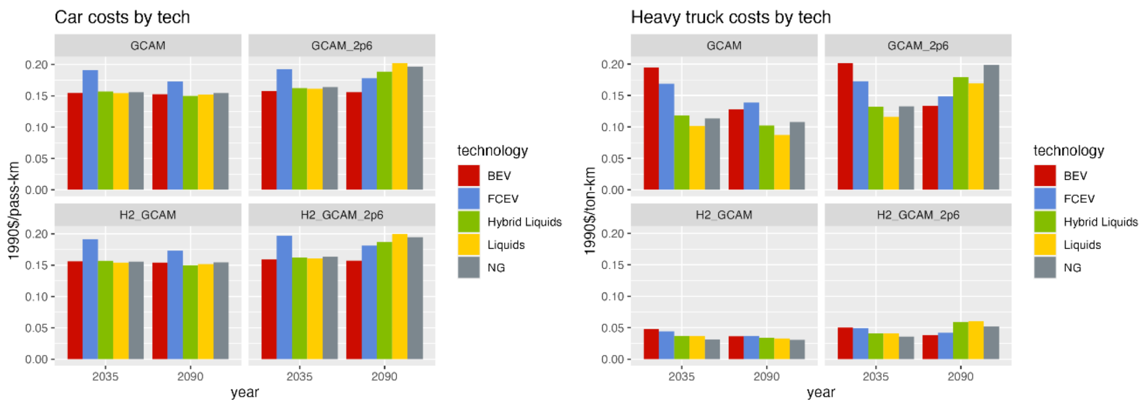

Figure 13. Levelized service costs in the model's units (1990$/passenger-km, 1990$/tonne-km) for Cars (left panel) and Heavy trucks (right panel), by drivetrain technology and scenario, for the USA region.

Figure 14 shows GCAM-USA's hydrogen production by technology, and use by sector. The left panel indicates that the baseline scenario's hydrogen production mix is reasonably similar, though the additional hydrogen demands in the 2050-2100 time period are largely met with wind electrolysis, and the policy scenario sees expansion in wind electrolysis, with less dependence on coal and gas with CCS than is seen in the core model. The general patterns from the core to the revision are similar to the shifting shown in Figure 5, albeit to a greater extent. On the consumption side (right panel), the difference from Core to the H2 revision is almost entirely due to hydrogen used by medium and heavy-duty trucking, with smaller differences due to backup electricity and light duty vehicles.

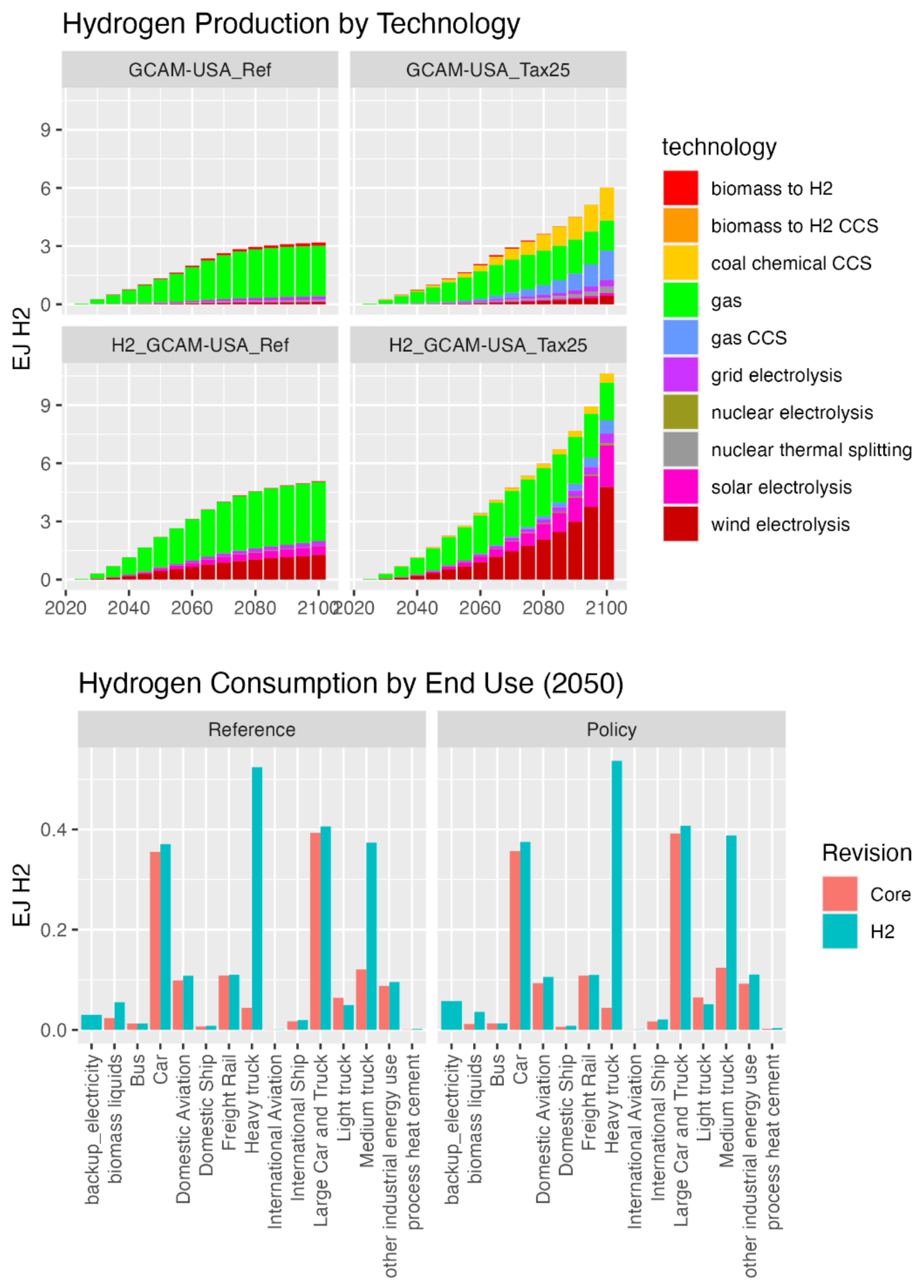

Figure 14. Hydrogen production by technology (left panel), and hydrogen consumption by end-use application in the year 2050 (right panel), focusing on the difference between the core model and H2 revision.

Figure 15 shows total final energy by fuel, across all end use sectors, for the 4 scenarios analyzed. Total final energy is similar between the core and H2 revision scenarios, and the higher demands of hydrogen in both the baseline and tax cases displace nearly equivalent volumes of refined liquids consumption, with comparatively negligible impacts on any other fuels.

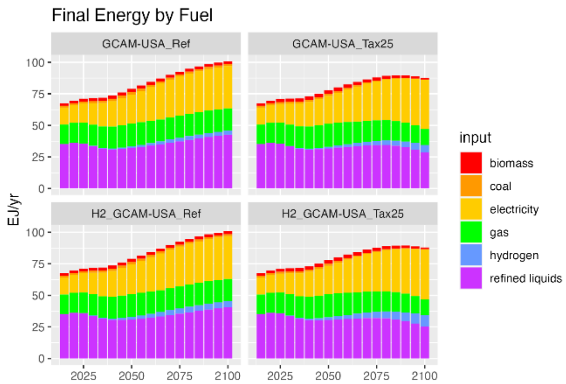

Figure 15. Total final energy by fuel and scenario in GCAM-USA.

In summary, the proposal implements a large number of changes that generally consist of updates to numerical data assumptions that improve the consistency with the current literature on various technologies, close several gaps that were important in policy scenarios. Because of the off-setting nature of these revisions--most importantly, allowing hydrogen combustion turbines as a backup power technology, while closing an apparent hydrogen-BECCS-cogeneration loophole, the net effect on most variables of interest is relatively modest, though we do see slightly lower CO2 prices in low-emissions scenarios.

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