Deconstructing the Hype on Hydrogen Hubs

By Bruce Buckheit

The Department of Energy (DOE) is poised to fund a significant expansion of hydrogen manufacturing and infrastructure, with $8 billion available to support an estimated 6 to 10 ‘clean' hydrogen hub projects. This funding was appropriated with instructions, driven by the politics of the day, which could result in the hydrogen hub funding being directed towards projects that undermine emission reduction efforts or even increase emissions. This same political motivation established a weak ‘clean’ hydrogen standard that allows for a significant portion of carbon emissions to be excluded from analysis of the carbon intensity of hydrogen production.

However, the DOE has discretion to determine what type of projects to prioritize for funding and should use its purview over project selection to ensure funding for ‘clean hydrogen’ is directed only towards the projects that can demonstrate the highest climate pollution reduction and sustainability gains. Given finite climate funding and resources, this should be considered in the broader context of how the carbon reduction potential of each proposal compares to alternatives, such as direct investment in renewable energy integrated into the grid. Further, the full lifecycle emissions of hubs must be considered prior to funding, and selected projects must document and publicly report the hub’s full lifecycle emissions throughout operation. For hydrogen hubs producing hydrogen through steam methane reformation (SMR), this analysis must include upstream leakages, otherwise the actual climate impact of this production would be misrepresented to decision-makers.

<u>*Key Findings*</u>

- The current clean hydrogen standard will result in more than twice the reported greenhouse gas (GHG) emissions if all associated emissions are considered. Hydrogen production at the standard will emit 4.77 metric tons (mt) CO_2e per mt H_2.
- A full analysis of grey and blue hydrogen, including methane leakage associated with SMR-produced hydrogen, demonstrates that these fuels increase rather than decrease energy carbon intensity.
- Due to high energy demands of manufacturing green hydrogen and the need to dramatically decrease the carbon intensity of our grids, green hydrogen is only suited to limited end-uses. Careful consideration of more efficient alternatives, such as direct electrification, should be conducted before investing in green hydrogen.
- Hydrogen demonstration hub funding should be directed towards projects demonstrating end-uses with the best climate and sustainability outcomes compared to alternatives. The DOE’s standards for funding demonstration projects appear to preclude many of the proposed end-uses suggested by advocates of a hydrogen economy.

<u>Overview of Federal Hydrogen Hype</u>

The role of hydrogen in climate policy has become a major source of controversy. Billions in new federal spending will soon be steered towards manufacturing hydrogen, but questions remain about whether and how these investments will lower emissions--or if they will have the opposite effect. Manufacturing hydrogen is an expensive and energy intensive process that results in net energy loss. This raises the need to carefully consider when and where hydrogen use is appropriate. This paper sets out a protocol and representative calculations illustrating the impact of the hydrogen end-use diversity provision in the Infrastructure Investment and Jobs Act (IIJA). Sec. 30314 of the IIJA provides federal funding opportunities for hydrogen hubs that would "demonstrate" potential use of hydrogen in the transportation, power, heating, and industrial sectors.[1] Industrial use of hydrogen in certain applications has been documented over several decades and so will not be addressed here.

As contemplated in early 2021, the IIJA "hubs" would have been paired with provisions of the proposed Build Back Better Act that would incentivize and ultimately mandate steady progress towards a less carbon intensive grid. However, the IIJA passed and the Build Back Better Act did not. This contributed to a skew in federal support. Plants that manufacture commercially available wind and solar technologies in Alabama, Arkansas, Colorado, Iowa, Kansas, Oregon, Pennsylvania, and South Dakota have laid off employees and closed.[2] Meanwhile DOE has underwritten a $500 million loan for partial powering of a single gas-fired power plant with hydrogen and is preparing to issue grants of up to one billion dollars for projects that are far less useful in the near term than adding renewable energy (RE) to the grid today and which, over time, may prove to be useful only in very limited applications.

IIJA also established a clean hydrogen standard that can be applied as a requirement for federal funding, allowing for an onsite process emissions rate of up to 2 kilograms (kg) of carbon per kg of hydrogen. However, by ignoring upstream emissions and the emissions from energy needed to drive the SMR process, this standard misrepresents the actual carbon intensity of the hydrogen that is produced. The decision to restrict analysis to facility-level emissions was likely done to allow hydrogen produced from SMR natural gas with CCS (blue hydrogen) to qualify under the clean hydrogen standard. However, failing to count emissions does not negate their impact. Assuming a facility meets but does not exceed the clean hydrogen standard, it will be responsible for over twice as much GHG emissions as it claims on paper -- emitting 4.77 mt CO2e per mt of hydrogen produced, plus approximately 8 mt of captured carbon dioxide which must be stored in perpetuity.

The DOE has the authority[3] to improve the current clean hydrogen standard by requiring analysis of full lifecycle emissions and limiting awards to projects that, at least, provide some reduction in CO_{2e} emissions compared to alternatives. It must exercise this purview and ensure that the

[1] As explained below, by specifying the types of projects that must be funded Congress ignored the recommendations of DOE's Energy Research and Development Agency Task Force on the use of demonstration projects to advance broad energy goals.

[2] Wind turbine manufacturing plant in Arkansas to close | AP News; Wind energy plants in Kansas, Iowa closing, could reopen | Miami Herald; Hutchinson Siemens plant temporarily shutting down in July, most employees to be laid off #IA #KS | Energy Central; Wind power manufacturer closing Colorado plant, laying off hundreds in consolidation | Wind Energy News (wind-watch.org); South Dakota rocked again as a wind turbine plant shuts its doors (msn.com); TPI Composites to close Iowa wind turbine blade plant;| S&P Global Market Intelligence (spglobal.com); Wind energy company closing Lehigh Valley manufacturing plant, shifting work to Mexico – The Morning Call (mcall.com); LG to exit solar panel manufacturing and close Alabama plant (solarpowerworldonline.com); SunPower to close Ore. solar panel factory | S&P Global Market Intelligence (spglobal.com); Mitsubishi Power Americas, Inc. | Advanced Clean Energy Storage Project Receives $500 Million Conditional Commitment from U.S. Department of Energy (mhi.com).

[3] As established in Division D, Title III, Subtitle B, Sec. 40315 of the Infrastructure Investment and Jobs Act: "Not later than the date that is 5 years after the date on which the Secretary develops the standard under subsection (a), the Secretary, in consultation with the Administrator of the Environmental Protection Agency and after taking into account input from industry and other stakeholders, as determined by the Secretary, shall (A) determine whether the definition of clean hydrogen required under paragraph (1)(B) should be adjusted below the standard described in that paragraph; and (B) if the Secretary determines the adjustment described in subparagraph (A) is appropriate, carry out the adjustment"

definition of clean hydrogen does not undermine climate goals. Although the DOE has indicated that it will conduct a full lifecycle analysis of proposals and give preference for projects with project lifecycle GHG reductions across the full project lifecycle, inclusive of hydrogen production, compared to the current industry standard,[4] it is unclear what this will achieve given that the vast majority of existing hydrogen production in the U.S. is grey hydrogen, which is already rightfully excluded from qualifying as clean hydrogen. Ultimately, the solution to ensuring 'clean' hydrogen aligns with climate and programmatic goals, is for the DOE to exercise its authority to ensure the clean hydrogen standard requires a full lifecycle analysis.

DOE and many commenters appear to recognize that the role of hydrogen in our future energy mix, if any, is likely limited to certain industrial applications and, perhaps, some small segments of other sectors. Others, with substantial investments in fossil reserves and/or SMR capacity, suggest a broad, "Hydrogen Economy" is just over the horizon[5], much as fossil industry representatives have suggested that carbon capture and sequestration (CCS) was just over the horizon for the past 20 years.

DOE should ignore the "Hydrogen Economy" hype and limit IIJA hydrogen hub awards to proposals that are directed at sectors where there is a reasonable likelihood of meaningful carbon emission reductions that could not otherwise be achieved. Absent a reliable regulatory scheme to provide for well closures and sequestration site monitoring, maintenance, and remediation *in perpetuity* DOE should not fund demonstrations that rely on continued production of natural gas coupled with CCS.

<u>Parameters and Metrics</u>

This paper focuses on 2030-2050, the time frame during which the policy is intended to limit the potential peak impacts of technology options that can be implemented over the next 20 years and where facilities employing those technologies have a useful life of 20-30 years. For this reason, this paper focuses on the 20-year global warming potential (GWP) of methane rather than the 100-year GWP.

Since the larger federal policy is intended to evaluate and develop potential pathways to carbon-free solutions in the relevant sectors, the metric of interest is the relative carbon effectiveness of all alternatives that would receive any federal support – either direct support or preferential tax treatment. Accordingly, various hydrogen schemes are compared to the carbon effectiveness of direct investment in RE integrated with the grid to determine whether those alternatives are a better use of available federal resources for addressing climate change. In particular, these alternatives are compared to two technologies that are commercially demonstrated, reasonably priced, and growing in popularity – battery electric vehicles (BEV), now being sold by over a dozen manufacturers in the U.S. - and heat pumps, which have been the technology of choice for

[4] https://oced-exchange.energy.gov/FileContent.aspx?FileID=72980077-30f7-4c57-b1e2-7b0bf8e52697 "While all projects will be required to meet the minimum clean hydrogen production standard, DOE intends to also evaluate full lifecycle emissions for each application and will give preference to applications that reduce GHG emissions across the full project lifecycle, inclusive of hydrogen production, compared to current industry standards."

[5] See, for example, the "Hydrogen for EU" Report, sponsored by BP, ConocoPhillips, Concawe, ENI, Equinor, Ervia, ExxonMobil, Gassco, Hydrogen Europe, IOGP, Norwegian Oil & Gas Association, OMV, Shell, Snam, Total, Wintershall Dea, Zukunft Gas. https://www.hydrogen4eu.com/. See also, reports by the U.S.-based Fuel Cell and Hydrogen Energy Association, including https://www.fchea.org/us-hydrogen-study.

residential space heating in much of the U.S. for over a decade. These technologies can have very low CO_{2e} emissions if the electricity they require is generated solely by renewable sources.

However, as illustrated by Tables One and Two, the actual emissions of BEVs and heat pumps depend on the carbon intensity of the grid. Today's grid generally functions on the basis of bids ordinarily[6] related to the running cost (mostly fuel cost) of generation. Commonly referred to as "merit order dispatch", this process ordinarily results in the dispatch of RE and nuclear power and then higher operating cost resources, typically combustion turbines or storage, as needed to meet anticipated demand. Adding RE to the available mix shifts the entire stack and leads to less use of the higher operating cost (and higher emitting) resources. EPA has developed a tool, AVERT[7], to permit developers, policy makers, and others to calculate the marginal emission rate (MER) impact of adding RE to the grid based on hourly generation patterns within 10 regions across the U.S. EPA's AVERT MER data were used to calculate the impact of the additional demand from the grid to charge the growing number of battery powered electric vehicles and heat pumps.

From these data we see that a Hyundai Kona BEV has essentially the same carbon emissions as its gasoline-powered counterpart - if charged from the grid in the Central, Rocky Mountain, and Midwest areas of the country. In the first quarter of 2019, the United Kingdom (UK) reported an average emission rate of 441 lb/MWh, demonstrating that the U.S. can emit at substantially lower levels with technologies that are available and affordable today. If charged from the UK grid, a BEV Kona would emit at one-fourth the rate of a gasoline-powered Kona. Because of California's aggressive actions to reduce the carbon intensity of its grid, a California-based Kona BEV would generate one-third fewer emissions than a Midwest Kona BEV.

Table One. CO_{2e} Emissions (mt/yr.) - Transportation

MER (lb/CO_2/MWh)	Kona (gas)	Kona (BEV)	HD Truck (diesel)	Battery Electric Truck (BET)
U.S. (1400)	4.34	3.79	219.04	210
CA (1000)		3.03		168
TX (1220)		3.45		204
Central, Rocky Mountain, Midwest (1700)		4.36		241
Hypothetical 2030 (700)		2.46		136
UK 2019[8] (441)		1.24		69

[6] There are circumstances where certain facilities are "must run" to support grid stability and for other purposes, circumstances where operators run at a loss for certain periods of time and circumstances where state regulators permit "out-of-merit-order" generation.
[7] https://www.epa.gov/avert.
[8] First Quarter 2019 average emission rate (not MER).

Similarly, replacing natural gas-fired heat with an electric heat pump in the Midwest provides only a 13% reduction in annual CO_{2e} emissions, but would reduce emissions by 75% in the UK or 40% in California. Reducing the average US MER to 700 lb/MWh would enable heat pumps to reduce GHG emissions by 50% compared to the most efficient natural gas-fired home heating systems.

Table Two. CO_{2e} Emissions (mt/yr.) – Home heating

MER (lb/CO_2/MWh)	Heat pump	Hybrid heat pump (85/15%)[9]	natural gas fired boiler
US (1400)	4.21	4.42	5.59
CA(1000)	3.37	3.70	
TX (1220)	3.83	4.09	
Central (1700)	4.84	4.95	
Hypothetical 2030 (700)	2.74	3.16	
UK 2019 (441)	1.38	2.01	

These comparisons demonstrate that the potential efficacy of these "off-the-shelf" technologies is severely constrained by the lack of investment in reducing power sector emissions and provide a strong argument for a strong focus on policy options that will maximize the use of RE, storage, and transmission upgrades.

<u>The Role of Demonstration Projects</u>

One of the politically driven provisions in IIJA's hydrogen hub provisions was an 'end-use diversity' instruction, which requires hub selection include end-use demonstrations in the power, heating, transportation, and industrial sectors. While it may be prudent to pursue basic research in "any and all" potential measures that may ultimately be helpful in addressing climate change, a "demonstration" project should not be funded until and unless fundamental barriers to the application of the technology have been resolved and a pathway to successful application of the technology can at least be reliably forecast. Moreover, unless there is a specific reason, projects should be designed to add to the body of knowledge in the area and not merely replicate demonstration projects that have been or are being pursued by others.

How, when and whether to conduct "demonstration projects" has been the subject of professional evaluation within DOE for several decades. In particular, DOE's Energy Research and Development Administration (ERDA) sponsored a "blue chip" agency/industry *Task Force on Demonstration Projects* to examine how to assist in commercialization of new energy technology

[9] Assumes partial use of natural gas (15 percent of overall heat needs) to supplement heat pump in colder climates.

by prototype demonstrations. The report of that task force[10] set out *Demonstration Project Guidelines*[11] that include:

- Establishing that the proposed project would either accelerate the commercial availability of a potentially attractive technology or develop a technical contingency against an uncertain future.
- Avoiding being committed in advance to particular technical solutions ("ERDA's clear responsibility is to assure that the most effective use is made of committed Federal funds, which the Task Force interprets to include more stringent and earlier screening to eliminate forcefully non-commercializable projects and programs, except in those cases where ERDA is consciously developing a contingency option for which economic criteria are not applicable").
- Ensuring that the technology is ready for demonstration (noting that "rushing into demonstration projects before the technology was ready has contributed to failures of such projects in the past").
- Ensuring that the technology is economically viable (noting that "[e]conomic viability is critical when the government is proceeding on the basis of the acceleration rationale.).

In particular, the Task Force warned against the impact of political pressure on decisions of whether to conduct demonstration projects

> *"While such [political] pressure can be helpful, it is often counterproductive. Political pressure was the basic cause of failure in five major government demonstrations the Task Force studied."*
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> *   *.   *.   *.
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> *"Curiously, political pressures can be generated by technologies that are demonstrably not cost-effective. It is only necessary that they function reliably and look cost-effective to some observers*."[12]

Political pressure has led historically to counterproductive investment, and could very well contribute to misallocation of the $8 billion appropriated for hub funding. Even should the instructions regarding hydrogen hub end uses remain unchanged, the DOE has purview to prioritize funding towards projects with the highest utility. This should be done in accordance with its own internal findings on the role of demonstration projects.

<u>Hydrogen-based Technologies</u>

There are two main technologies for producing hydrogen - electrolysis and synthetic methane reformation (SMR) of natural gas.

As DOE concedes, electrolysis has a major obstacle, in that:

> *"Today's grid electricity is not the ideal source of electricity for electrolysis because most of the electricity is generated using technologies that result in greenhouse gas emissions and are energy intensive. Electricity generation using renewable or nuclear energy technologies, either separate from the grid, or as a*

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[10] www.osti.goc/servlets/purl/1131059
[11] Supra, at Section IV.
[12] Id, at page 18.

> *growing portion of the grid mix, is a possible option to overcome these limitations for hydrogen production via electrolysis."*[13]

Hydrogen production using SMR is less dependent on the carbon intensity of the electricity supply, since the process requires much less electricity than electrolysis. But SMR-produced hydrogen using natural gas emits between 8 and 12 lb of CO_2 for each lb of hydrogen produced; coal gasification emits 18 – 20 lb CO_2 per lb hydrogen. For this reason, advocates for "clean" SMR-produced hydrogen (also known as "blue" hydrogen) must rely on claims of very high levels of carbon capture and sequestration (CCS) that have not yet been achieved in practice and that are likely to be uneconomic for any application other than enhanced oil recovery (EOR), which is counter to the curtailment of fossil fuel utilization[14]. The CCS process also requires additional energy for capture, compression, and storage - further reducing the net carbon effectiveness of blue hydrogen compared to grey hydrogen (SMR-produced hydrogen without CCS).

The carbon emission intensity of SMR-produced hydrogen is also highly dependent on the upstream emissions of methane. The additional energy requirements for CCS increases the amount of natural gas needed for an equivalent amount of grey hydrogen. Thus, the relative carbon intensity of these methods varies, depending on the amount of upstream leakage of methane that occurs. As leakage rates increase, the theoretical benefit of blue hydrogen declines and, under certain assumptions set out below, can be greater than continued use of unabated natural gas. The current clean hydrogen standard does not include analysis of these upstream emissions, which undermines its utility and risks the demonstration projects misrepresenting the actual impacts of the hubs.

Figure One, below, sets out different estimates of the greenhouse gas intensities of different forms of SMR-produced hydrogen compared to other fossil fuels over a broad range of assumed methane leak rates. The assumed methane leak rate clearly has a very substantial impact on the relative carbon intensity of SMR-produced hydrogen with and without CCS.

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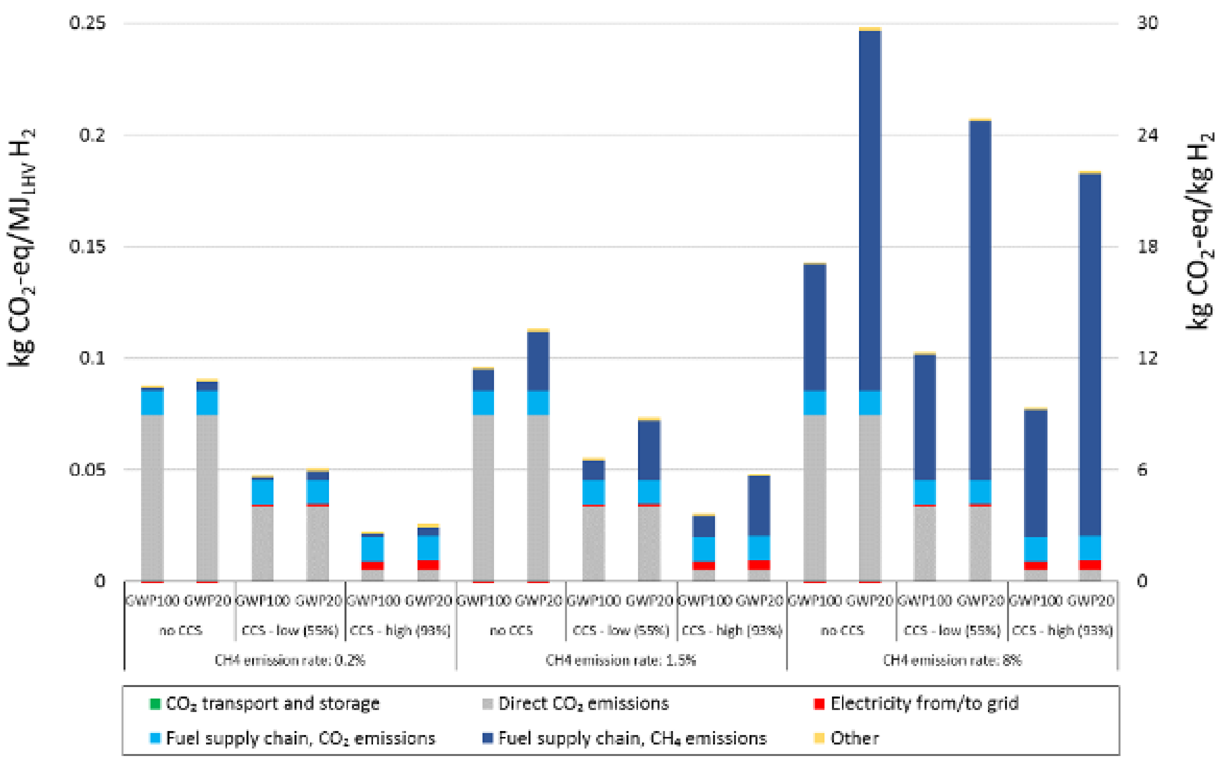
[13] https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis

[14] EOR itself is inconsistent with the goals of the program since it is intended to lower the price and thereby increase consumption of fossil fuels.

Figure One, Bauer, et al, Blue Hydrogen Emission Rate Estimates[15]



Upstream methane leakage is outside of the control of SMR operators and may not be known to Hub participants. Further, the IIJA Hydrogen Hub demonstration criteria do not establish a limit on upstream methane emission losses. Unless the remit of the "blue" Hydrogen Hub is expanded to include an evaluation of the upstream losses for natural gas used at the Hub in a way that can be extrapolated to the broader universe[16], the Hub may be able to document whether high onsite CO_2 capture efficiencies can be maintained but will not be sufficient to document the carbon intensity of "blue" SMR/CCS technology. This is problematic when hydrogen projects are claiming onsite carbon intensity as the extent of their GHG impact and thereby qualifying for climate funding.

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[15] Bauer C, Treyer K, Antonini C, Bergerson J, Gazzani M, Gencer E, et al. On the climate impacts of blue hydrogen production. ChemRxiv. Cambridge: Cambridge Open Engage; 2021; This content is a preprint and has not been peer-reviewed.

[16] S&P Global Platts markets "Methane Performance Certificates" issued by Xpansiv where the leakage at the production site is monitored pursuant to "established third party standards, protocols and certifications to continuously monitored data. Thus far, no peer reviewed evaluation of the Xpansiv protocols has been identified. Presumably such certificates would be issued based on the performance of the wells at the time of production and would not evaluate emissions during (fracking) well development, over the lifetime of the well or post closure. https://plattsinfo.spglobal.com/methane-pricecertificates.html?utm_source=google&utm_medium=social&utm_content=searchad&utm_term=field-marketing&utm_campaign=2022EnergyTransitionNewLogoNorthAmSocialMethanePerformance&gclid=CjwKCAjwu_mSBhAYEiwA5BBmf8igxVlBXzuvke0bnZtWFss7T2VN1b0ANWgDAYXOF_uvCgrFQStcqBoCNugQAvD_BwE

A greater challenge for SMR-produced hydrogen projects than the obvious technical and cost issues is the development of regulatory and financial mechanisms to ensure that the vast quantities of CO_2 captured at the time of production remain sequestered *in perpetuity* -- the technical feasibility of which has been questioned by many scientists. Legacy coal, oil and gas production has left this country with innumerable orphan piles of coal waste, and hundreds of thousands of abandoned wells[17] and unrestored sites for which no funding mechanism was in place while those sites were active. The risk that today's producers may spin off and seek bankruptcy protection for activities with high long-term exposure is higher if the country does succeed in dramatically reducing the use of fossil fuels, including so-called "blue" hydrogen, as revenue from these product streams declines. For this reason, any demonstration of SMR-based hydrogen production should include adoption and demonstration of practices to monitor, detect and correct leakage These sequestration risks also heighten the importance of the clean hydrogen standard requiring a full lifecycle analysis of hydrogen – the current standard not only misrepresents the actual carbon intensity of blue hydrogen, but also relies on the unproven feasibility of safely storing massive amounts of carbon in perpetuity.

Comparative Analysis of Hydrogen End-uses

Hydrogen in the Power Sector

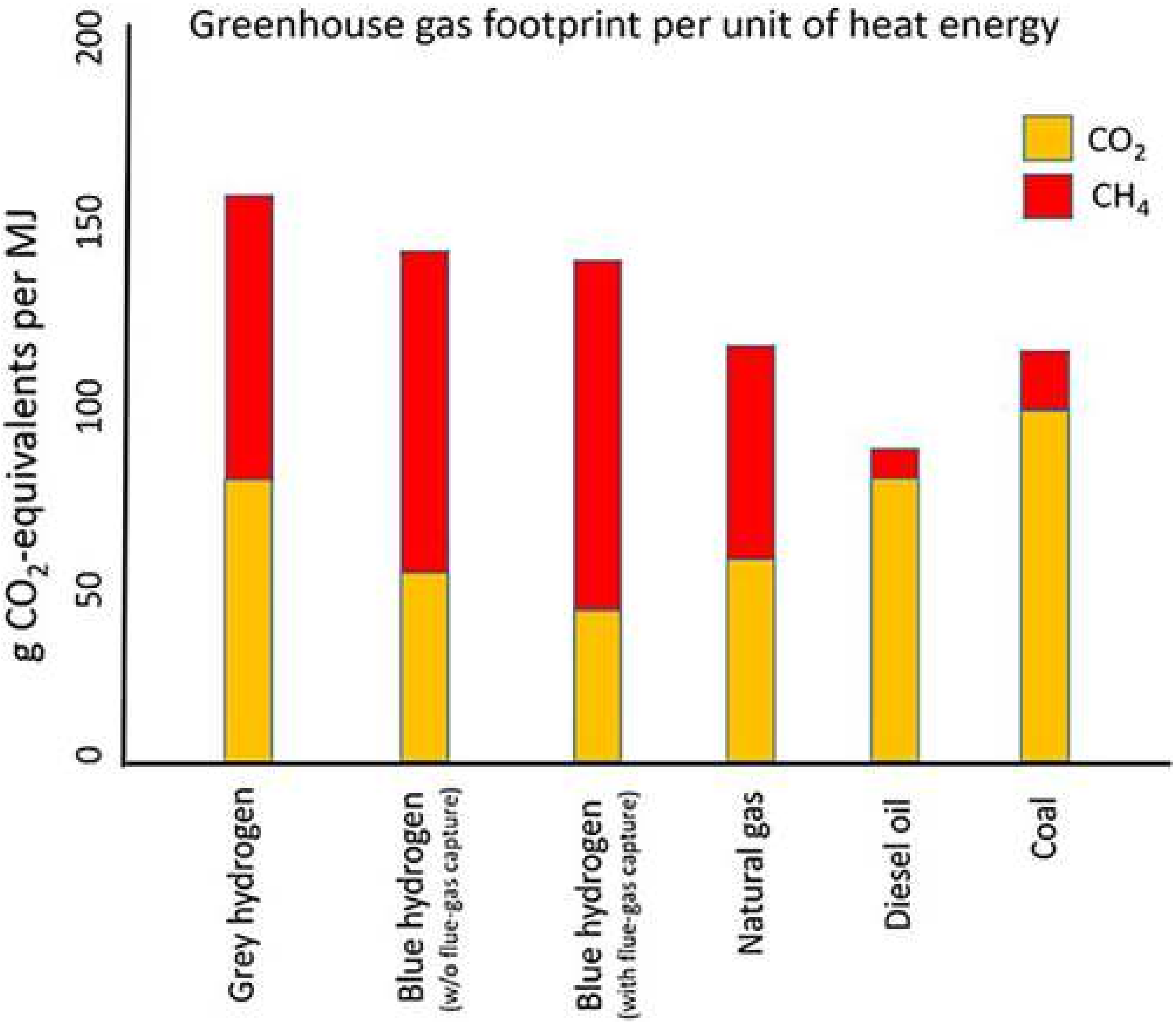
- Producing grey or blue hydrogen from natural gas, then combusting the hydrogen for power increases grid carbon intensity and creates more GHG than simply combusting the natural gas.
- Using green hydrogen in the power sector risks slowing decarbonization efforts. In many cases, RE can more effectively displace polluting energy sources if added to the grid rather than being used to produce green hydrogen.
- Alternative storage options are often better suited to the needs of a region's power demands than green hydrogen

Comparing Natural Gas (NG) Combustion Turbines (CT), Hydrogen Electrolysis CT, Hydrogen SMR CT, and RE/Storage

As Figure Two illustrates, depending on the actual methane emission rate, using grey or blue hydrogen to generate power in a combustion turbine can lead to greater CO_{2e} emissions than simply combusting natural gas.

[17] How the US plans to plug 1 million toxic 'orphan' oil wells | Watch (msn.com); Rewriting Pennsylvania's Legacy (pa.gov); Canada's oil and gas decommissioning liability problem | IEEFA

Figure Two, Howarth and Jacobsen Estimate (3.5% methane leak rate, 20 year GWP) [18]



Even at lower methane leak rates, the use of hydrogen for power generation has not been shown to be technically feasible or environmentally acceptable. Thus far, proposed hydrogen demonstration projects offer only limited blending of hydrogen with natural gas. This is because higher proportions of natural gas pose technical issues that have not been solved at this time – and which may not be solvable.

However, utilities are using these low hydrogen blending proposals as justification to continue investment in natural gas capacity. - several of the current proposals suggest a 30/70 blend of hydrogen to natural gas. In these proposals only 11% of the energy would come from hydrogen.[19] Conversely, even this limited blending of hydrogen (with higher flame temperature) with natural gas significantly increases emissions of nitrogen oxides (NOx), which can form fine particulate matter ($PM_{2.5}$) or ozone. Because hydrogen has a relatively low energy density, meaningful direct

[18] https://onlinelibrary.wiley.com/doi/epdf/10.1002/ese3.956
[19] The energy density of natural gas in 40 MJ/m^3; hydrogen's energy density is 13 MJ/m^3.

emission reductions from even a 75% blend of green hydrogen/natural gas would only reduce direct CO_2 emissions by 50%.

The obvious issue associated with generating RE and then using that RE to produce hydrogen by hydrolysis and then using that hydrogen in a combined cycle gas turbine (CCGT) to make electricity is the very low efficiency of the overall system compared to simply integrating that RE into the grid. An "electricity-to-gas to electricity" option requires very large infrastructure to manufacture, store and contain a very low-energy density gas. Hydrogen advocates concede this fact but suggest that "since hydrogen can be stored indefinitely" it should be considered useful to support intermittent RE options.

There are many different ways of storing energy, each with strengths and weaknesses. Hydrogen production and storage requires very large infrastructure to manufacture, store and contain a very light gas and should be compared to electricity storage options such as large scale battery, cascading water storage, and other storage technologies. Energy vector transition losses suggest that with hydrogen storage 55% of the input energy (whether RE or produced by other means) is lost in the "electricity-to-gas-to-electricity" energy conversions. [20]

Table Three below was prepared by the World Energy Council. It includes commercially available technologies that can currently provide large storage capacities of at least 20 MW.

Table Three. Characteristics of Alternative Energy Storage Technologies[21]

	Max Power Rating (MW)	Discharge time	*Max cycles* or lifetime	Energy density (watt-hour per liter)	Efficiency
Pumped hydro	3,000	4h – 16h	30 – 60 years	0.2 – 2	70 – 85%
Compressed air	1,000	2h – 30h	20 – 40 years	2 – 6	40 – 70%
Molten salt	150	hours	30 years	70 – 210	80 – 90%
Li-ion battery	100	1 min – 8h	*1,000 – 10,000*	200 – 400	85 – 95%
Lead-acid battery	100	1 min – 8h	6 – 40 years	50 – 80	80 – 90%
Flow battery	100	hours	*12,000 – 14,000*	20 – 70	60 – 85%
Hydrogen	100	mins – week	5 – 30 years	600 (at 200bar)	25 – 45%
Flywheel	20	secs - mins	*20,000 – 100,000*	20 – 80	70 – 95%

[20] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis; Mix of mechanical and thermal energy storage seen as best bet to enable more wind and solar power | Energy (stanford.edu); Round Trip Efficiency - an overview | ScienceDirect Topics

[21] Characteristics of selected energy storage systems (source: The World Energy Council)

> *"The technology to convert power to hydrogen and back to power has a round-trip efficiency of 18%-46%, according to data that Flora presented from the Massachusetts Institute of Technology and scientific journal Nature Energy. In comparison, two mature long-duration technologies, pumped-storage hydropower and compressed air energy storage, boast round-trip efficiencies of 70%-85% and 42%-67%, respectively. Flow batteries, a rechargeable fuel cell technology that is less mature, have a round-trip efficiency of 60%-80%."*[22]

<u>Intermountain IPP Case Study</u>

DoE recently announced a conditional loan commitment of $504 million to Mitsubishi and local developers[23]to build what the developers style as the world's largest hydrogen hub. The hub will initially be designed to convert renewable energy through 220 MW of electrolyzers to produce up to 100 metric tons per day of green hydrogen, which will then be stored in two salt caverns each capable of storing 150 GWh of energy. This facility will supply hydrogen feedstock to the Intermountain Power Agency's (IPA) IPP Renewed Project — an 840 MW hydrogen capable gas turbine combined cycle power plant — that will initially run on a blend of 30% green hydrogen and 70% natural gas by volume starting in 2025 and, according to developers, will increase to 100% by 2045. The IPP Renewed Project includes the retirement of the existing coal-fueled units at the IPP site and modernization of IPP's Southern Transmission System linking IPP to Southern California.

Closing existing coal units and upgrading transmission lines are positive developments. But it should be understood that if and when the plant commences operating on a 70/30 blend (by volume) of natural gas to hydrogen, 89% of the energy would be from the natural gas.[24] At a 50% capacity factor, overall plant generation would be 3,865 GWh. The hydrogen component of that generation would be 424 GWh. In addition, over some (undefined) period of time the operator asserts that it can store 300 GWh of hydrogen energy storage (or 150 GWh of electricity at 50% efficiency for the CCGT).

But Southern California's greatest need is short term ramping and storage flexibility for three to four hours at a time – not long term inter-seasonal grid support.[25] The first ramp of 8,000 MW in the upward direction (duck's tail in the figure below) occurs in the morning starting around 4:00 a.m. as people get up and go about their daily routine. The second, in the downward direction, occurs after the sun comes up around 7:00 a.m. when on-line conventional generation is replaced by supply from solar generation resources (producing the belly of the duck). As the sun sets starting around 4:00 p.m., and solar generation ends, the Independent System Operator (ISO) must dispatch resources that can meet the third and most significant daily ramp (the arch of the duck's neck). Immediately following this steep 11,000 MW ramp up, as demand on the system deceases into the evening hours, the ISO must reduce or shut down that generation to meet the final downward ramp (producing the belly of the duck).

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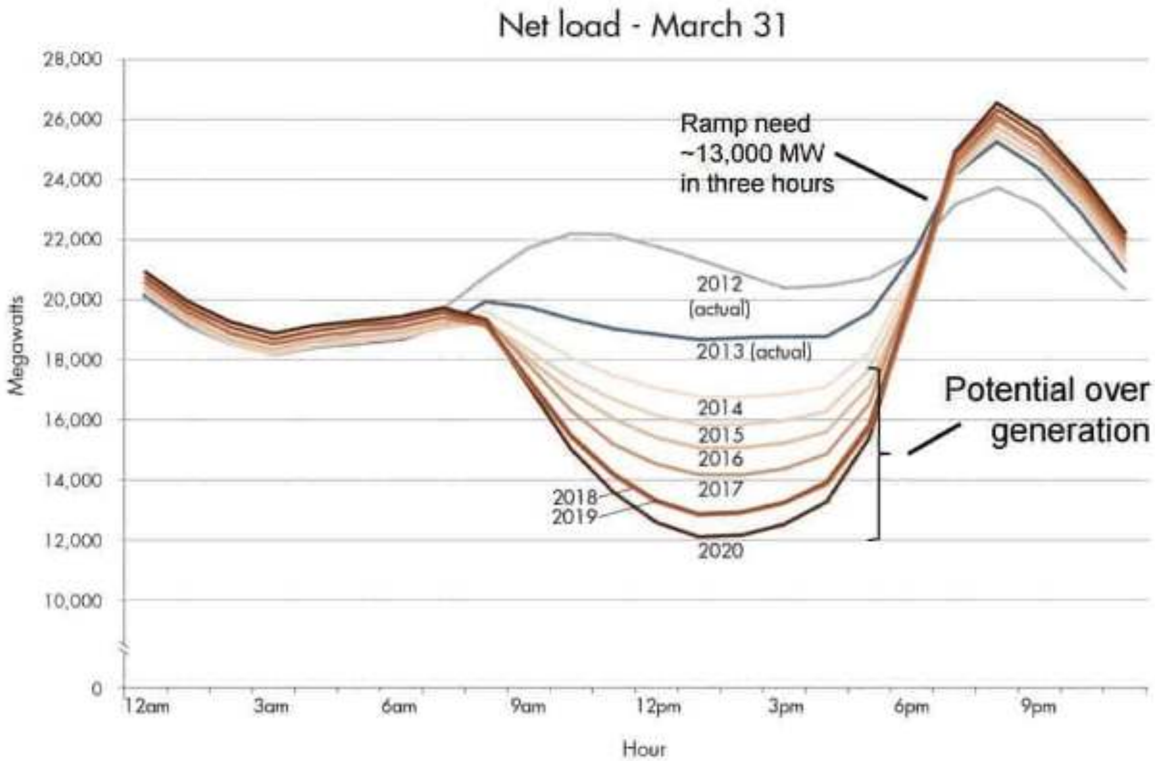
[22] Hydrogen technology faces efficiency disadvantage in power storage race | S&P Global Market Intelligence (spglobal.com)

[23] Mitsubishi Power Americas, Inc. | Advanced Clean Energy Storage Project Receives $500 Million Conditional Commitment from U.S. Department of Energy (mhi.com); IPP Renewed – Intermountain Power Agency (ipautah.com) Detailed documentation is not available online.

[24] The energy density of natural gas in 40 MJ/m^3; hydrogen's energy density is 13 MJ/m^3.

[25] flexibleresourceshelprenewables_fastfacts.pdf (caiso.com); Understanding the California Duck Curve for Daily Load Projections - Aurora Solar

Figure Three: California Grid Demand



If the IPP Project employed 220 MW of solar generation at a 29% capacity factor it would generate 1,118 GWh/yr. of electricity. With 90% round trip short-term storage efficiency and sufficient transmission capability, that would enable the facility to ship 920 GWh/yr. of RE to Southern California to help address the evening ramp,[26] roughly twice the contribution of the green hydrogen that is contemplated. Table Four sets out the estimated annual CO_2 and CO_{2e} emissions avoided by 220 MW green hydrogen and solar/battery options.

Table Four. Estimated Emissions Avoided by Solar/hydrogen and Solar/battery Options

	CO_2 (mt/yr.)	CO_{2e} (mt/yr.)
H2 (solar/electrolysis)	192,323	357,592
Solar/battery	417,305	775,906
Difference	224,982	418,315

[26] Transmission during the day would also reduce the need for gas-fired generation.

Over the 20 year useful life of the project, CO2e emissions will be on the order of 10 million metric tons higher than if a standard solar/battery project had been adopted. The hydrogen storage capacity can provide about 5% of the generation capacity of the IPP Renewed CCGT (though initially limited to a maximum of 11% of the input energy). Since the facility cannot operate at higher blend rates, it seems likely that the principal use of the hydrogen storage component of the project would be to compensate for days without substantial sunshine and optimize the natural gas/hydrogen blend rate. Since the CCGT can operate at lower hydrogen blend rates generation supplied to Southern California is not affected by lower solar production on cloudy days. On an annual basis, the amount of RE in the mix provided to Southern California can be increased simply by adding more solar capacity to the project.

Hydrogen in the Transportation Sector

- EVs offer better carbon reduction potential than hydrogen fueled cars, and this gap will likely continue to grow as grids increase renewable capacity.
- Due to inefficiencies and energy loss, hydrogen fueled cars require twice as much energy as EVs, meaning that scaling-up green hydrogen for use in transportation could slow efforts to reduce grid carbon intensity.

Comparing Battery Electric Vehicles (BEV), Hydrogen Fuel Cell Vehicles (FCEV), and Conventional Motor Vehicles

In Table Five the annual CO_{2e} emissions for three comparable passenger motor vehicles are calculated, assuming the electricity needed for the BEV and FCEV comes from the grid (or from sources that could otherwise be connected to the grid). The references to "blue" hydrogen" assume that the "clean hydrogen" definition of the IIRI (2 lb-CO_2/lb-H_2 – at the site[27]) is used.

[27] It appears that DOE intends that this limit is applied to emissions from the SMR reactor only and not the CO_{2e} emissions associated with the energy needed to drive the process. The IIRI is clear that the definition of "clean hydrogen" does not include offsite methane losses.

Table Five. Representative CO_{2e} Emissions from Light Duty Vehicles (metric tons per year)

	Kona (gasoline)	**Kona (BEV 3.5%/1.5%)**	**Nexo (FCEV electrolysis)**	**Nexo (grey)**	**Nexo (blue) 3.5/1.5%**
U.S. (1400)	4.34	3.30/3.02	23.49/21.51	4.31/3.07	2.48/1.35
CA (1000)		2.36/1.89	16.79/13.48		2.45/1.31
TX (1220)		2.87/2.49	20.41/17.77		2.47/1.33
Midwest[28] (1700)		4.00/3.22	28.52/22.92		2.51/1.37
hypothetical 2030 (700)		1.65/1.33	11.75/9.44		2.44/1.30
UK 2019 (441)		1.04/0.83	7.40/5.94		2.36/1.23

Table Six. Representative CO_{2e} Emissions from Heavy Duty Trucks (metric tons per year)

	Class 8 diesel	**BET**	**FCET electrolysis**	**FCET (grey)**	**FCET (blue)**
U.S. (1400)	219	183/167	1276/1159	264/180	145/79
CA (1000)		131/105	912/718		143/77
TX (1220)		159/138	1108/953		145/79
Midwest (1700)		222/178	548/1221		147/80
hypothetical 2030 (700)		91/73	688/553		140/73
UK 2019 (441)		58/46	402/316		138/72

Here we see that, based on the U.S. average MER, the Hyundai BEV's annual emissions are only 25% lower than the gasoline powered Hyundai – and that, in much of the country –including the Central, Rocky Mountain, and Midwest Regions, the BEV's CO_{2e} emissions are not substantially less than the gasoline powered Hyundai's emissions. This relationship persists when comparing heavy duty trucks and, for both classes of vehicles, is more pronounced in areas of the country where higher emitting sources are at the margin more hours of the year.

[28] Includes Midwest, Central and Rocky Mountain states.

These figures highlight a critical issue for policy makers. Waiting for grid-generated electricity to be clean enough to achieve immediate decarbonization as drivers abandon conventional cars will unacceptably delay the timeline of the transition, but – *as BEVs become mainstream, it is critical to ensure that the carbon intensity of the grid is reduced to the greatest extent practicable.* This is especially true for marginal emitters in lower carbon-intensity states. Doing so makes the most cost-effective use of the investment of those who purchase EVs and the federal and state incentives for BEVs.

These results also demonstrate that, by the time SMR technology could be widely employed at scale, hydrogen-fuel cell vehicles would not likely be lower emitting than BEVs charged on the grid.

Hydrogen in Residential Space Heating

- Electric heat pumps offer better carbon reduction potential than hydrogen, and this gap will likely continue to grow as grids increase renewable capacity
- Due to hydrogen's high energy demands, scaling-up hydrogen for uses where direct electrification is a feasible alternative would slow efforts to reduce grid carbon intensity

<u>Comparing Electric Heat Pumps, Natural Gas-fired Boilers, and Oil- Fired Boilers</u>

As with BEVs, the carbon intensity of competing space heating strategies depends on the MER of the grid providing electricity for heat pumps, complicated by "timing and weather issues." Of most relevance to the carbon intensity of heat pumps is the MER when heat pumps are most likely to be used and the number of hours when temperatures are below the optimal range for heat pumps.

Researchers at the UC Davis Cooling Efficiency Center have published a study using a proprietary tool similar to AVERT to compare the CO_2 emission rate of several heat pump options with the performance of residential natural gas-fired boilers in a wide range of marginal GHG emissions rates throughout the year across the USA.[29] Because heat pumps transfer heat from outside air (even when cold) to the inside of the residence, rather than merely adding heat, they can be extremely efficient, often adding three times as much heat to the residence compared to the energy needed to run the equipment. But, because of the relatively low thermal efficiency and high carbon content of the fossil generating equipment that often supplies the MER, the study finds that in most states a natural gas-fired boiler has a lower CO_2 emission rate than a grid-powered pump. Only seven states have sufficiently low MER, coupled with reasonable temperatures, so that any of the heat pump technologies provide a measurable improvement over a natural gas-fired boiler. The Southeast and Midwest states that have thus far lagged in adopting RE show the greatest disparity. This is particularly unfortunate in the Southeast where CO_2 emissions from heat pump use are 10 -110% greater than gas-fired heat and where moderate winter temperatures are optimal for heat pump use, which could greatly reduce regional CO_2 emissions if coupled with a greener grid.

Table Seven. Metric tons of CO_{2e} per year to heat a 2200 square foot residence[30]

[29] https://wcec.ucdavis.edu/wp-content/uploads/GHG-Emissions-from-Residential-Heating-Technologies-091520.pdf

[30] This calculation assumes the AVERT emission level for each region. The calculation does not take into account the different levels of heat needed in each region and so, represents an "apples-to-apples" comparison based on the characteristics of the grid, but not local weather conditions.

**Assume 3.5%/1.5% methane losses*	**Natural gas fired boiler**	**Heat pump**	**Hybrid heat pump (85/15)**	**H2 -fired boiler (hydrolysis)**	**H2-fired boiler (Blue H)**	**H2-fired CT/CCGT & heat pump**
US (1400)	5.59/3.79	4.44/3.66	4.61/3.68	17.91/14.79	9.87/5.83	6.25/3.69
CA (1000)		3.91/1.62	4.16/2.80	15.78/10.57		
TX (1220)		4.22/3.18	4.42/3.28	17.01/12.85		
Midwest (1700)		4.84/4.45	4.95/4.35	19.51/17.95		
Hypothetical 2030 (700)		2.74/1.83	2.33/2.13	11.04/7.40		
UK 2019 (441)		1.72/1.15	2.30/1.55	6.95/4.66		

As in the Transportation Case, the relative carbon-effectiveness of hydrogen-based alternatives depends heavily on the extent to which today's heat pump systems are coupled with a clean grid. Under most reasonable assumptions concerning the future MER of the U.S. grid, neither grey nor blue hydrogen offers any significant advantage over adding all available RE to the grid. The carbon-effectiveness of blue hydrogen systems also depends on:

(1) whether the analysis includes CO_{2e} emissions associated with methane leakage and with the heat energy needed for the SMR process;

(2) whether operators are able to identify and implement a system for perpetual monitoring, care, and remediation of CO_2 sequestration sites; and

(3) the ability of regulators to track, characterize and limit methane emissions well below current levels.

Conclusion

Green hydrogen can play an important role in decarbonizing industries that cannot be feasibly electrified. However, recent hydrogen hype threatens to undermine the utility of hydrogen in climate policy. The current clean hydrogen standard will result in more than twice the reported greenhouse gas (GHG) emissions. It could also play a significant role in slowing RE grid decarbonization and electrification efforts, while embedding natural gas energy capacity.

The DOE has a responsibility to ensure the clean hydrogen standard does not allow for a misrepresentation of the actual climate impact of hydrogen. This will require the DOE to conduct a full lifecycle analysis of proposals. Further, the DOE must prioritize its own policies for demonstration projects over political pressure. Hydrogen funding should only be directed towards projects that will demonstrate meaningful GHG reductions and sustainability gains over its full lifecycle, compared to potentially more efficient alternatives.

APPENDIX A

Blue Hydrogen

Estimates by Howarth and Jacobson[31]

	Gray H2	Blue H2 (w/o flue-gas capture)	Blue H2 (w/flue-gas capture	Natural gas
Fugitive CH4 = 3.5%				
GWP20 = 8	153	139	135	111
GWP20 = 105	170	158	155	123
GWP100 =34	106	86	77	76
Fugitive CH4 = 4.3%				
GWP20 = 86	117	159	156	124
GWP20 =105	192	182	181	139
GWP100 = 34	113	94	86	81
Fugitive CH4 = 2.54%				
GWP20 = 86	133	115	109	95
GWP20 =105	144	129	124	104
GWP100 = 34	98	76	67	70
Fugitive CH4 = 1.54%				
GWP20 = 86	110	90	82	79
GWP20 =105	117	98	91	84

[31] https://onlinelibrary.wiley.com/doi/epdf/10.1002/ese3.956

GWP100 = 34	89	67	57	64

APPENDIX B – READING LIST

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