Blue Hydrogen – Not A Bad Idea

S. C. (John) Gülen, Bechtel Fellow, ASME Fellow
Kiran Chaudhari, Senior Technical Advisor
March 4, 2024

In a recent GTW article [1], the first author wondered about the feasibility of betting on hydrogen as a gas turbine fuel to decarbonize the electricity sector. He ended his discussion as follows:

> *What **green hydrogen** from renewable-powered electrolysis can exactly accomplish in terms of reducing CO_2 emissions from grid-scale electric power generation is not clear at all to the author. Even using the entire curtailed wind generation in the U.S. to make H_2 and burn it in GTCC cannot make a proverbial pinprick in GHG emissions.*
>
> *Using the best possible assumptions, including 100% H_2 burning DLN combustors, the impact is much smaller than 1% - not surprising because the generated H_2 can only support a couple of state-of-the-art GTCC power plants at most. One can certainly throw in curtailed solar energy into the mix, but this will not change the answer by a whole lot. (Consider that, per U.S. EIA, in 2020, CAISO curtailed 1.5 million MWh of utility-scale solar (vis-à-vis 13 million MWh curtailed wind for the entire U.S.), which is 5% of total production.)*

At the same time, there is no doubt that gas turbines will play a major role in decarbonization of the electricity sector. Again, from the same article:

> *Finally, per U.S. EIA (June 9, 2021), over the past 15 years, the U.S. electricity generation mix has shifted away from coal and toward natural gas and renewables, resulting in lower CO_2 emissions from electricity generation. In 2019, the U.S. electric power sector produced 1,724 million metric tons of CO_2, **32% less** than the 2,544 million metric tons produced in 2005. Now, this is real decarbonization!*

In the same article, the author also made a somewhat risky (under the light of the recent Kemper IGCC debacle, maybe even foolhardy) proposal, i.e., that

> *[t]here is a rationale behind making blue hydrogen via **gasification** of coal, refinery residue, or other problematic hydrocarbons. Unlike the electrolysis or SMR (or its derivatives or close relatives), in this case, the feedstock, in contrast to surplus electric power plus water or natural gas (mostly methane, that is), is typically not considered to be a good candidate for 'clean' electric power generation.*

In this article, we will look at a technology that can generate hydrogen and power from gasification of a blend of biomass and coal with a "net negative" CO_2 footprint. Let us, however, first take a look at an earlier attempt to gasify coal and generate electric power with pre-combustion CO_2 capture. While the attempt was not exactly a stellar success, at least based on what can be gleaned from superficial press articles, the reality is quite different. This is why it deserves a closer look because its demise was a

significant factor (by no means the only one, though) in putting an end to the efforts to maintain coal as a viable option for electricity generation (see the 2007 GTW article on that subject [2]).

Kemper IGCC

The Kemper County IGCC Project was supposed to demonstrate the state-of-the-art *Transport Integrated Gasification* (TRIG™) technology at a 2x2x1 Integrated Gasification Combined Cycle (IGCC) facility in Mississippi. The facility showcased the largest IGCC project (net 582 MWe) ever implemented, the first to use lignite coal as fuel for gasification, the pioneer to capture and sell CO_2 from coal gasification syngas, and the first to produce multiple byproducts such as anhydrous ammonia and sulfuric acid from the startup. If the plant had become commercially operational with lignite coal, the Kemper Project would have been a first-of-a-kind (FOAK) coal to power plant to employ gasification and carbon capture technologies at this scale. The plant achieved overall 224 days of gasifier operation of coal-to-power with carbon capture and sequestration (CCS) as per the proposed design until it met its obvious fate in June 2017 [1]. This ill fate put all other proposed gasification with CCS projects on hold or pushed them to cancellation.

Figure 1 Kemper IGCC (Today, Mississippi Power's Kemper County Energy Facility (Plant Ratcliff) – a natural gas fired GTCC power plant. Unused gasification and process facilities were demolished in 2021.)

The outcome of the Kemper IGCC project should not decide the fate or viability of gasification and CCS. It would be wrong to say that it was categorically a technology failure. Many issues beyond the technologies deployed in the project contributed to its final destiny. Unfortunately, published sources fail to highlight what Kemper IGCC project achieved and demonstrated at scale during its short runtime. Yet, analysis done on the plant operational data as shown in Figure 2 indicated that Kemper's planned

availability and reliability targets were in par with first applications of other large coal gasification projects in its initial year.

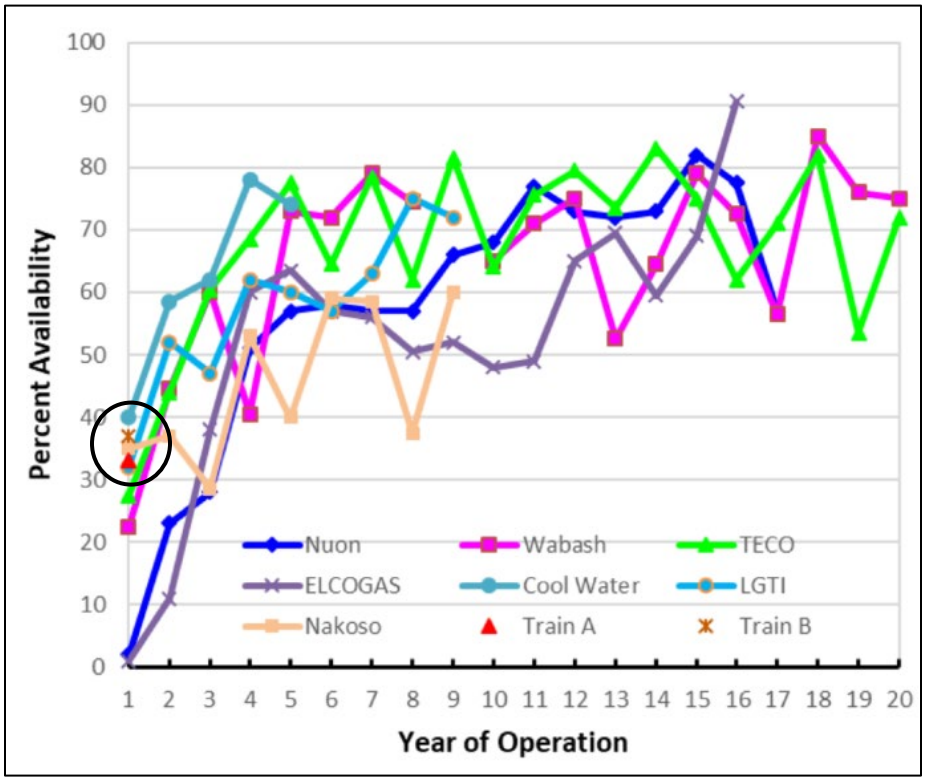

Figure 2: Realized availabilities based on syngas production for various IGCC facilities across the world when compared to Train A and Train B at Kemper IGCC [1]

Kemper IGCC was a FOAK project to implement coal gasification with carbon capture at commercial scale. The project was challenging since its inception due to a high degree of integration between different process blocks with a complex execution scheme. There were several issues that led to the project's ill-fated end in addition to the FOAK nature of the overall system. They included

- nearly 80x scale up from the pilot plant,
- lignite coal feedstock with high moisture, high ash and fines content,
- troublesome solids handling system,
- ambitious project planning and poor communication,
- premature equipment procurement,
- unexpected construction delays, and
- compressed commissioning schedule.

In addition to those technical issues, a steep drop in natural gas prices at the time made it difficult to argue that rate payers should continue to carry the burden for fixing the gasification island. Other than

the TRIG™ gasifier and ash removal systems, most of the other technologies in the overall process scheme were demonstrated at commercial level in similar services in the past. In some instances, these technologies took longer time to come online due to myriad factors such as improper material selection, unforeseen feed impurities, tube and flange leaks, and extended turndown operation. Details on these issues can be found under the *Kemper County IGCC Final Project Report* submitted in 2019 (https://www.osti.gov/biblio/1513228).

The project was the first to demonstrate carbon capture from coal syngas with UOP's Selexol acid gas removal (AGR) technology, producing hydrogen-rich syngas for the gas turbines. When the gasifier operation improved and delivered steady, on-spec syngas to the AGR unit, a CO_2 capture rate of 65-75% (occasionally reaching up to 80%) was achieved as shown in Figure 3. In the final analysis, regardless of the challenges associated with the project due to its size and novelty, the short-lived Kemper IGCC plant proved the feasibility of coal gasification with carbon capture process to produce hydrogen-rich syngas.

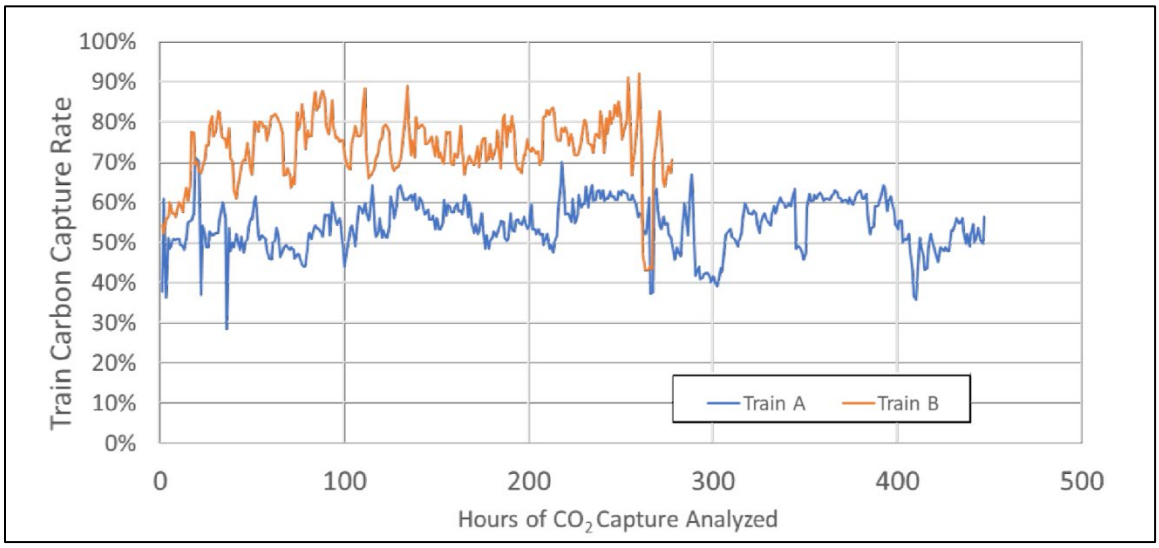

Figure 3 Acid Gas Removal CO_2 capture rate with time for Train A and Train B at Kemper IGCC [3]

Which "Blue"?

Hydrogen is the holy grail of clean combustion for electric power generation. The main combustion product is water vapor. The downside is, of course, hydrogen is not readily available; it has to be produced. If hydrogen production, storage, and transportation are CO_2-free, then the mission of CO_2-free power generation is accomplished. This is potentially but not necessarily (and not fully) true for H_2 production from water via electrolysis using CO_2-free power, e.g., wind, solar, hydro, or nuclear. This is referred to as "green" hydrogen ("pink" in the case of nuclear). While it is certainly true that the aforementioned technologies generate power without CO_2 emissions, their "greenness" is not an automatic given. Only "excess" kilowatts from these resources can be considered green. Otherwise, each kilowatt diverted from the electric grid to electrolysis of water to make H_2 is replaced by a kilowatt

with a certain CO_2 footprint. Due to the limited availability of excess green energy and the exorbitant power consumption of the electrolyzers, there is a strict limit to the availability of "green" H_2, which, by the way, is too expensive to make economic sense – at the time of writing and also in the near future.

Hydrogen produced using *steam methane reforming* (SMR), the established thermal technology to make hydrogen, comes with a substantial CO_2 footprint, i.e., 9-10 kg of CO_2 emitted for each kg of H_2 produced (plant stack basis, *not* life cycle). The redeeming feature of SMR-produced H_2 is its low price. The remedy proposed to alleviate its CO_2 baggage, "blue" H_2, incorporates carbon capture to the SMR plant. This may indeed be an attractive candidate for industrial H_2 production without concomitant CO_2 emissions. However, it involves a trade-off because the most commonly used feedstock, natural gas, can be directly used in a GTCC for electric power generation with the lowest possible CO_2 footprint of all the fossil fuel-based technologies (60-70% less than that of coal-fired power plants). Furthermore, with post-combustion CO_2 capture, it can be CO_2-free as well. In other words, each kilogram of blue H_2 using natural gas as feedstock has an "opportunity cost" in missed CO_2-free electricity generation, which is substituted by the grid with its own CO_2 footprint.

Luckily, SMR (and its up-and-coming alternative, *autothermal reforming* (ATR), more on that below) is not the only thermal technology to make H_2 from a hydrocarbon feedstock. Gasification of coal or another hydrocarbon feedstock to produce a syngas, which, after being scrubbed of CO_2 (and H_2S), can be treated in an adsorption process to separate high-purity H_2 from the remaining components. Captured CO_2 can be sequestered or used in an industrial process such as EOR. In comparison to SMR, blue H_2 from coal is more expensive but, at least at the present, less expensive than green H_2 from electrolysis. An in-depth comparison is strongly dependent on respective feedstock prices and the gasification technology used. Other factors that will play a role in comparative ranking of H_2 production options are tax credits and future advances in electrolyzer technology and increased deployment lowering unit prices.

The attractiveness of blue H_2 from coal (or other environmentally undesirable hydrocarbon feedstocks) stems from the fact that it is one potential way to make a "green" product from an otherwise unusable (especially in North America and Europe) but ample energy resource. That way, natural gas can be reserved for low-carbon electric power generation in gas turbine power plants. Furthermore, by blending coal with carbon neutral biomass (as per EPA guidelines), "net negative" carbon emissions can be achieved as well.

Gasification for Blue H_2

In a recent study funded by the U.S. DOE, a conceptual design has been developed for a pilot plant to produce net negative carbon H_2 and power from gasification of coal and biomass [4]. A simplified block diagram of the plant is provided in Figure 1. The feedstock is PRB subbituminous coal and corn stovers in a composition 50-50 by weight (dry basis). Raw syngas is produced in an oxygen-fed, pressurized gasifier. The syngas treatment includes water-gas shift (to convert CO in the syngas to CO_2), gas cooling, and acid gas (CO_2 and H_2S) via chemical absorption. Treated, hydrogen-heavy syngas undergoes *pressure swing adsorption* (PSA) to separate 99% pure H_2 from the gas stream. The remaining "tail" gas is burned in a gas turbine combined cycle power plant to generate electric power. Part of the generated power is utilized within the plant and the balance is fed to the grid.

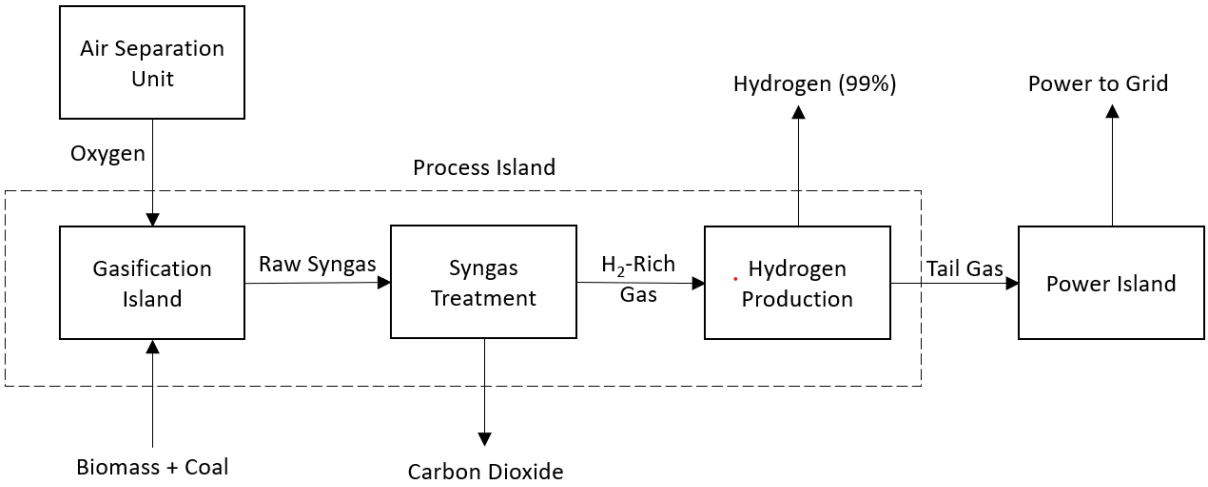

Figure 4 Block flow diagram of the coal plus biomass co-gasification plant for production of hydrogen and power

The gasification technology, GTI Energy's proprietary U-GAS®, is an advanced, single-stage, fluidized-bed gasification process. In the gasification island, a lock hopper system supplies dry fuel into the gasifier, where the fuel reacts with steam and oxygen (from an air separation unit, ASU) at 1,100 °C (2,000 °F). The gasifier's operating pressure is 30 bar. Generated syngas is fed to dual cyclone separators, which remove particulates that are recycled back into the gasifier. Hot syngas from the cyclone separators is cooled by generating high pressure superheated steam before passing through a filter system to remove fines. The fines from the filter system are also recycled back into the gasifier, and particle free syngas then passes through a wet scrubber to remove ammonia, hydrogen chloride and hydrogen cyanide gases and other water-soluble contaminants that readily dissolve in the water and form salts.

The scrubbed gas is then routed to the downstream *Water Gas Shift* (WGS) reactor for further processing and to increase the syngas hydrogen content (also referred to as *sour gas shift*). The WGS process consists of reacting a mixture of steam and hydrocarbons at a high temperature to form a mixture of hydrogen and oxides of carbon in a packed-bed catalytic reactor with the WGS catalyst. Shifted gas composition is primarily CO_2 and H_2 (about 47% and 42% by volume, respectively).

Selexol *Acid Gas Removal* (AGR) process is used to remove and recover H_2S and CO_2 in the shifted gas. The system is sized to remove CO_2 more than that generated from coal gasification, including some from the (carbon neutral) biomass gasification; thus, making the project *net-negative carbon* from the perspective of overall plant emissions. Of the overall CO_2 produced by the gasification process, about 60% is attributed to carbon in the PRB coal with the balance attributed to carbon in the corn stover. Capture efficiency is close to 70%.

A LO-CAT® unit removes the remaining H_2S from the AGR off-gas stream. This is an aqueous-based, ambient temperature process that utilizes a chelated-iron catalyst to convert the H_2S to elemental sulfur for removal. The LO-CAT process is located downstream of the AGR. This allows it to treat a much smaller stream containing only CO_2 and H_2S rather than the full syngas stream; thus, reducing equipment size and cost.

The cleaned gas with primary constituents of H_2 (about 75%(v)) and CO are separated through a conventional *Pressure Swing Adsorption* (PSA) process with >99 %(v) hydrogen purity. PSA is a constant temperature process comprising alternating steps of pressurization and depressurization driving adsorption and desorption of impurities in the feed gas. High purity hydrogen product at a rate of 8,500 kg/h (283.3 MWth LHV) is released at the top of the adsorber vessels (typically, there are four of them). Desorbed impurities leave the adsorber at the bottom of the vessel as the "tail gas" stream.

The tail gas from the PSA containing 34%(v) H_2 is burnt in two Siemens SGT-800 industrial gas turbines in a 2x2x1 combined cycle configuration. The SGT-800 gas turbine can burn high-hydrogen fuel gas with low CO and NOx emissions in compliance with the current EPA regulation without diluent injection. The three-pressure (no reheat) bottoming steam cycle is integrated with the gasification island and syngas process blocks. Carbon dioxide from the HRSG stack gas is not captured.

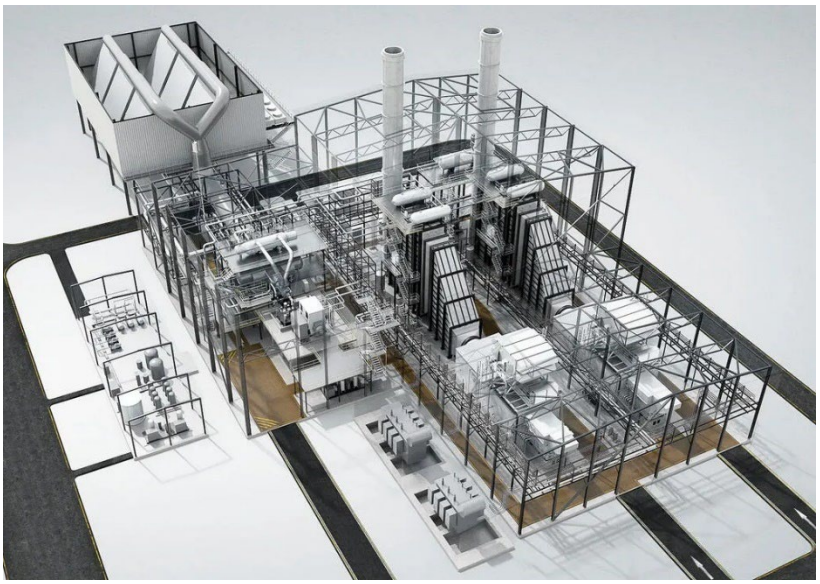

Figure 5 Siemens SGT-800 combined cycle

Power block gross output is 134 MWe, out of which 84 MW is spent by the plant systems including the ASU (~30 MW) and the CO_2 compressor (~18 MW). (Gross efficiency of the power block is 56.7% LHV.) Thus, net 50 MW is supplied to the grid. If the ASU is owned and operated by the ASU vendor (their preferred business model), net output to the grid increases to 80 MW. Oxygen used by the gasifier is purchased from the ASU vendor.

Feedstock consumption by the plant is, on an as received basis, ~2,000 STPD coal and ~1,600 STPD corn stover (686.5 MWth HHV total). Overall cogeneration efficiency, based on hydrogen product in LHV and net power output, is 48.7% HHV (52.9% HHV if the ASU is outside the plant battery limit). Assuming an optimistic 60% conversion efficiency for the hydrogen product (i.e., assuming that the power plant burning H_2 is located next to the gasification cogen plant – no storage, transport, leakage, and other performance debits), effective electric efficiency is 32% HHV (36.4% HHV if the ASU is outside the plant battery limit).

Using an SMR thermal efficiency range of 65% to 75% on LHV basis (i.e., LHV of hydrogen produced as a fraction of the LHV of CH_4 feedstock), with the same optimistic 60% conversion efficiency (with the

caveats already mentioned), the effective electric efficiency of gray H_2 via SMR is 0.65 to 0.75 x 0.6 or 39% to 45% LHV. There are two options to make the product chain from natural gas feedstock to power plant generator terminals (almost) carbon neutral: (1) "blue" H_2 by adding carbon capture to the SMR or (2) adding post-combustion capture to the GTCC. The penalty would be anywhere 10% to 15% depending on a multitude of factors. Thus the efficiency range would be around 33% to 40% LHV.

In other words, the net negative carbon coal and biomass gasification for H_2 and power cogeneration is readily competitive with blue H_2 via SMR on *performance-only* basis. Thus, the cost comparison between the two technologies becomes the key differentiating factor. Steam reforming of natural gas is a mature technology widely used for industrial hydrogen production and, presently, the least expensive one at about $1/kg or less (from the chart in https://www.iea.org/data-and-statistics/charts/hydrogen-production-costs-using-natural-gas-in-selected-regions-2018-2, last updated in June 2019). With carbon capture, it is predicted to go up to anywhere between $1.5/kg (USA) to more than $2/kg in Europe (the same source). This is a tough benchmark to beat. In addition to CAPEX and OPEX of the plant (Phase 2 FEED study for Class 3 estimate is in the works), the levelized cost of H_2 (LCOH) depends on the cost of the corn stover pellets, sale price of electricity, and financing costs. The location of the plant plays a significant role as well (e.g., access to coal and corn stover as well as CO_2 sequestration sites). Phase I study calculations showed that with IRA 45Q credits, and corn stover pellets costing about the same as PRB coal, an LCOH of $2/kg or less is possible. (At the time of the study economic analysis, 45V legislation was not released.)

Why Coal (and/or Biomass)?

Hydrogen is an important industrial feedstock. Current H_2 production is primarily via thermal means, to an overwhelming extent by steam reforming of natural gas (mostly methane) with a significant CO_2 footprint. Consequently, a transition to H_2 production technologies with little or no CO_2 emissions is a critical step towards slowing down and, ultimately, reversing the global warming caused by the *greenhouse gas* (GHG) emissions. Another significant step in that direction is decarbonization of the electricity generation sector. Replacement of coal with natural gas has been a strong positive factor in the latter endeavor (the record in the U.S. being a prime example as noted in the beginning). Especially with advanced class gas turbine combined cycle (GTCC) power plants equipped with 90-95% post-combustion carbon capture, electricity generation efficiency is well above 50% LHV.

Redirecting natural gas from electricity generation to hydrogen production beyond the currently existing levels is not a viable decarbonization move. If the hydrogen thus produced is used for electricity generation, its end result is *increasing* the CO_2 emissions (just compare the efficiencies calculated above, i.e., low to mid-30s in percent LHV for SMR with carbon capture). If the end use of hydrogen is industrial, it has an *opportunity cost* because it takes away from electricity generation to replace coal-fired power generation.

For all of its downside in terms of environmental unfriendliness, especially in the U.S., coal is a valuable energy resource. "Clean coal" for electric power generation has been tried and eventually dropped with practically zero possibility of coming back. "Clean coal" for hydrogen production, on the other hand, is a potentially (but by no means guaranteed) cost-effective means to transform that relatively inexpensive resource to valuable "blue" hydrogen. In calculating the cost effectiveness of blue H_2 via coal and/or

biomass gasification, one should also factor in the release of natural gas for replacement of coal-fired electricity generation with concomitant CO_2 emission reductions.

A quick calculation can be done to demonstrate the above assertion. In a roughly 75% efficient (LHV basis) steam reforming process, 3.26 kg CH_4 is consumed to produce one kg of H_2 with 10 kg of CO_2 emissions. At 60% net LHV efficiency, typical of a modern GTCC power plant, the *opportunity cost* of not using CH_4 in electricity generation is 27.2 kWh with 9 kg of CO_2 emissions (330 kg/MWh). To generate the same electricity in a PRB subbituminous coal (7,500 Btu/lb LHV as received) fired SCPC (thermal) power plant with 40% net LHV efficiency, ~14 kg of coal is burned with 23.9 kg of CO_2 emissions (880 kg/MWh). Let us assume that the coal fired plant is replaced by a CH_4 burning GTCC and the same amount of coal thus released is used in the coal-biomass fired H_2-power coproduction plant described above. Hydrogen production is 1.28 kg with *negative* 5.9 kg of CO_2 emissions (as explained above). Note that to produce 1.28 kg of H_2 via SMR, we need to consume 4.15 kg of CH_4 with 12.8 kg CO_2 emissions.

Let us summarize:

- **BASE CASE**: 1 kg *grey* H_2 from 3.26 kg CH_4 via SMR plus 27.2 kWh electricity by burning 14 kg PRB coal in a thermal power plant
- **SWITCH CASE**: 1.28 kg *blue* H_2 plus 9.1 kWh electricity from 14 kg PRB coal (plus corn stover) in the gasification plant plus 27.2 kWh electricity by burning 3.26 kg CH_4 (not used for H_2 production) in a GTCC. The "switch" is two-fold:
    - Hydrogen production feedstock switch from CH_4 to coal
    - Electricity generation fuel switch from coal to CH_4

The comparison between the cases is summarized in Table 1. The "switch," as described above , increases both H_2 production and electricity generation (by one-third) while reducing CO_2 emissions by 91% (mass basis, 93% in per MWh terms). (Note that SMR electricity consumption, mainly H_2 compression, is ignored.)

Table 1 Feedstock switch from CH_4 to coal and vice versa for hydrogen production and electricity generation (increased H_2 production)

	CH_4 Burn, kg	Coal Burn, kg	Hydrogen, kg	Electricity, kWh	CO_2, kg (from H_2 Prod.) / (from Electricity	Total CO_2 kg / kg/MWh
BASE	3.26 (SMR)	14.0 (Thermal PP)	1.00 (Grey)	27.2 (Coal)	10.0/23.9	33.9/1,249
SWITCH	3.26 (GTCC)	14.0 (Cogasification)	1.28 (Blue)	36.3 (CH4 + Coal)	-5.9/9.0	3.1/85
DELTA	0	0	+0.28	+9.1	-15.9/-15.0	-30.8/-1,164

An alternative look is provided in Table 2. Extra H_2 production, in the first comparison summarized in Table 1, enables an additional fuel conversion, i.e., releasing more CH_4 from H_2 production to electricity

generation in a GTCC. As shown in Table 2, the result is even higher electricity generation (by nearly 60%) with 78% reduction in CO_2 emissions by mass (86% in per MWh terms).

Table 2 Feedstock switch from CH_4 to coal and vice versa for hydrogen production (SMR) and electricity generation (constant H_2 production)

	CH_4 Burn, kg	Coal Burn, kg	Hydrogen, kg	Electricity, kWh	CO_2, kg (from H_2 Prod.) / (from Electricity	Total CO_2 kg / kg/MWh
BASE	4.15 (SMR)	14.0 (Thermal PP)	1.28 (Grey)	27.2 (Coal)	12.8/23.9	36.7/1,351
SWITCH	4.15 (GTCC)	14.0 (Cogasification)	1.28 (Blue)	43.8 (CH4 + Coal)	-3.4/11.4	8.0/183
DELTA	0	0	0	+16.6	-16.1/-12.5	-28.7/-1,167

Autothermal Reforming (ATR)

SMR is the dominant commercial technology for hydrogen production, but it is not the only reforming technology. The up-and-coming *autothermal reforming* (ATR) is the other thermal technology of interest to produce hydrogen from natural gas as feedstock at commercial scale. ATR combines *partial oxidation* (POX) and steam reforming to produce a syngas with the inherent advantage of no external heat input. Hydrogen is separated from the syngas in a PSA system. Oxygen required for the ATR is supplied by a cryogenic ASU. On average, ATR consumes 3.5 kg of natural gas per kg of H_2 produced and it also comes with a substantial on-site CO_2 footprint, i.e., 8.3-9.3 kg of CO_2 emitted for each kg of H_2 produced (with no capture). Compared to SMR this process provides the benefit of capturing the majority of CO_2 (as much as 95% or higher) at pre-combustion stage.

POX by itself is not competitive with SMR, i.e., not a likely candidate for future blue H_2 production (see the article cited earlier for its performance [1]). The other technology that must be mentioned for the sake of completeness is *methane pyrolysis* (also referred to as methane *cracking* or *decomposition*), whose end product is solid carbon or "carbon black." This is a significant advantage vis-à-vis CO_2 capture via more complex amine-based chemical absorption. However, in order to bring methane decomposition temperatures to a level comparable to SMR, a catalyst is required. (A plant using Monolith's high temperature plasma torch and electricity to convert natural gas and nitrogen to carbon black with an ammonia byproduct (14,000 tons/year) has been in operation in Hallam, Nebraska since late 2020.) From a technology readiness perspective catalytic methane pyrolysis is behind ATR and likely to be costlier. Thus, the technology competition for blue H_2 production from natural gas (mostly methane) will most likely be between SMR and ATR with CCS. Representative process parameters are summarized in Table 3.

Table 3 Technology comparison (SMR and ATR)

	Cogasification	SMR	ATR	SMR	ATR
ASU for O_2?	YES	NO	YES	NO	YES
CO_2 Capture?	YES	NO	NO	YES (70%)	YES (90%)
H_2 per CH_4, kg/kg	0.09	0.31	~ same as SMR	0.31	~ same as SMR
CO_2 per H_2, kg/kg	-0.42 (CO_2 Removal)	9-10	~ same as SMR	3	0.9-1
Electricity Consumed, kWh/kg H_2	-0.65 (Elec. Gen.)	1.0	2-2.5	2-3	4

For grey H_2 production (no CO_2 capture), ATR performance is pretty much at par with SMR except power consumption (mainly due to the ASU). For blue H_2 production, ATR is the better choice with a lower CO_2 footprint than SMR. Furthermore, several studies have evaluated the ATR pathway to be slightly less expensive than SMR for blue hydrogen, especially at high capture efficiency. Looking at the recent trends, large scale ATR plants are expected to be a key producer of blue hydrogen and blue ammonia going forward. Thus, the feedstock switch scenario above is repeated by replacing SMR (grey H_2) with ATR+CCS (blue H_2) in the base case (same H_2 per CH_4 ratio on mass basis). The results are summarized in Table 4. Clearly, CO_2 emissions benefit is less pronounced than the base case with SMR (no capture) but still significant plus with the additional improvement in the extra electricity column. Either technology is at an early stage of development so that a reliable cost comparison at this stage would be subject to high uncertainty. Nevertheless, it is clear that cogasification of coal and biomass for H_2 *and* electricity cogeneration is a worthy competitor in the blue hydrogen realm.

Table 4 Feedstock switch from CH_4 to coal and vice versa for hydrogen production (ATR+CCS) and electricity generation (constant H_2 production)

	CH_4 Burn, kg	Coal Burn, kg	Hydrogen, kg	Electricity, kWh	CO_2, kg (from H_2 Prod.) / (from Electricity	Total CO_2 kg / kg/MWh
BASE	4.15 (ATR+CCS)	14.0 (Thermal PP)	1.28 (Blue)	23.2	1.28/23.9	25.2/1,089
SWITCH	4.15 (GTCC)	14.0 (Cogasification)	1.28 (Blue)	43.8 (CH4 + Coal)	-3.4/11.4	8.0/183
DELTA	0	0	0	+20.6	-4.7/-12.5	-17.2/-906

In Conclusion…

Coal (and biomass) gasification makes possible a beneficial switch between two hydrocarbon feedstocks, which significantly reduces the carbon footprint for the same amount of hydrogen production (by almost 80% on a mass basis) while increasing the electricity generation (by 60%). With generous tax credits and other financial incentives, the dollars and cents can work out favorably as well. It certainly

makes a lot of sense from the perspective of turning a valuable natural resource into a useful tool of decarbonization instead of letting it go unused underground.

Authors' Note: *The blue hydrogen production system described in this article is based on findings from a study supported by the U.S. Department of Energy under Award Number DE-FE0031993.*

References

1. S. Can Gülen, "Gas Turbines and Hydrogen – Let the Numbers Speak for Themselves," Gas Turbine World, December 2022, pp. 10-16.
2. H. Jaeger, "What it takes to equip IGCC and PC plants for CO_2 capture and storage," Gas Turbine World, March-April 2007, pp. 1-11.
3. Vimalchand, P., Hogg, Eamon, Pinkston, Tim, Madden, Diane Revay, and Lunsford, Landon. Kemper County IGCC (Final Project Report). United States: N. p., 2019. Web. doi:10.2172/1513228.
4. Matt Nelson, P. Vimalchand , Ryan Brown , Tim Pinkston, Raj Palla, Denise Voelker, Trevor Smith, Diane Madden, "Carbon Capture at the Kemper IGCC Power Plant", 14th International Conference on Greenhouse Gas Control Technologies, GHGT-14 21st -25th October 2018, Melbourne, Australia.
5. S. Can Gülen, B. Patel, D. Leppin, R. Maurer, H. Hack, R. Estrada, "Flexible Gasification of Coal and Biomass to Generate Carbon Free Electric Power and Hydrogen," 2023 International Pittsburgh Coal Conference, October 4 - 6, 2023, Istanbul, Turkey.