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Decarbonizing Natural Gas for Electricity Generation

Supported by WSAS Core Funding from the State of Washington

October 21, 2025

This document was prepared by a multidisciplinary team of WSAS members with relevant expertise in response to a request from the Governor's office to understand opportunities to decarbonize the conversion of natural gas to electricity. In creating this report, WSAS anticipated questions that any party might have in designing or evaluating an energy project using natural gas in Washington. The report was completed over a period of two months to provide a timely, high-level overview of technical and practical considerations in considering options for integrating natural gas into the state's energy mix. It is not comprehensive.

This project was funded with Washington state funding to the Academy "for core operations and to accomplish its mission of providing science in the service of Washington."

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The Challenge

Washington State and the Pacific Northwest face unprecedented growth in electricity demand driven by electrification of transportation and heating, plus new large loads from data centers and advanced manufacturing. Forecasters predict that the Pacific Northwest Region will need to add approximately 30 GW of new generation capacity over the next 10 years—a 53% increase from current levels of 57 GW [1]. Simultaneously, Washington has committed to achieving net-zero greenhouse gas emissions by 2050 under the Climate Commitment Act, with interim targets requiring a 45% reduction below 1990 levels by 2030 and a 95% reduction by 2050.

The electric power grid is one of the most complex human-engineered systems. To keep the power grid running smoothly, the amount of electricity being used must always match the amount being produced. While renewable sources like solar and wind are expanding, they cannot be readily ramped up when demand peaks. Future technologies like small modular reactors and fusion won't arrive in time to meet short-term demand growth. Natural gas, which currently provides 13% of Washington's generation capacity, represents a proven, dispatchable energy source for rapid deployment [3]. Deploying natural gas for increased electric capacity and grid resilience while meeting Washington's carbon reduction policy goals will require careful analysis of economic, technical, environmental, and societal factors for each use case.

Overview: How Natural Gas Becomes Electricity

Natural gas (methane or CH_4) can be converted to electricity through two main pathways:

1. **Direct Combustion**

    - **Combustion Turbines:** Fast start-up, ideal for meeting peak demand, but less efficient (similar to a jet engine)
    - **Combined Cycle Plants:** Use a gas turbine followed by heat recovery and steam production, which produces electricity in a steam turbine. Achieves up to 60% efficiency—among the most efficient fossil fuel technologies available but with increased capital cost [4].

    It is possible to reduce carbon emissions after direct combustion by using chemical solvents to separate CO_2 from flue gasses and store it. This is a mature but technically complex process.

2. **Pre-Combustion Conversion**

    Natural gas can also be converted to hydrogen through processes like:

    - **Steam Methane Reforming (SMR):** Mature, widely used technology but also produces CO_2
    - **Methane Pyrolysis:** Emerging technology that produces solid carbon instead of CO_2
    - **Other reforming methods:** Various approaches with different tradeoffs

    The resulting hydrogen can then power fuel cells or turbines, producing only water vapor at the point of use. It is possible to reduce overall carbon emissions and separate a relatively pure CO_2 stream from the conversion process [5]. Though it requires 20-40% more fuel to produce the same electricity from natural gas generated hydrogen vs. direct natural gas combustion [15, 17, 22], this can be a preferred pathway when hydrogen is already being produced or when grid balancing or other benefits of hydrogen provide sufficient value to offset the efficiency penalty.

Overview: Carbon Storage Technologies

Once captured either pre- or post-combustion, CO_2 can be:

- ***Stored underground*** in saline formations, depleted oil/gas fields, or basalt rock formations. Eastern Washington's basalt formations are particularly promising for large-scale storage —pilot projects show 60% of injected CO_2 mineralizes into rock within 3 years [28].
- ***Reused*** in products like building materials, chemicals, or carbonated beverages. However, scale is limited—one 500 MW plant produces 1-2 million tons of CO_2 annually, while global CO_2 product markets are only 230 million tons per year [34].

Key Considerations

When evaluating natural gas generation projects, decision-makers must weigh several critical factors that determine both the feasibility and desirability of proposed approaches.

1. Grid Reliability

The electric grid requires a constant balance between supply and demand. While renewable sources like solar and wind are expanding, they cannot be dispatched on demand. For example, solar energy generation peaks at midday but electricity demand peaks in the evening. Hydroelectric power, which provides 68% of Washington's current generation [2], has become less reliable during summer peak periods due to changing snowpack melting patterns and competing water uses [3].

Both natural gas and hydrogen can be ramped up quickly (in minutes or seconds, respectively) balance the grid at times of peak demand to avoid power outages.

2. Carbon Emissions

A key metric for comparing the carbon impact of different approaches is to calculate the lifetime carbon abatement cost (cost per ton of CO_2 avoided). Some questions to consider when evaluating carbon reduction include:

- **Life Cycle Assessment:** What are the total emissions from construction through decommissioning? Here are some life cycle considerations of the technologies described in this report [12-22]:
  - Simple cycle natural gas turbine technology without carbon capture is lower than coal plants but exceed the average U.S. grid emissions. [8]
  - Combined cycle natural gas turbines are similar to the average U.S. grid emissions.
  - Carbon capture can dramatically reduce carbon emissions. Combined cycle plants with 95% capture approach the emissions levels of nuclear energy and renewables.
  - Direct combustion of natural gas in combined cycle plants generally produces lower lifetime emissions than converting to hydrogen first.

- **Additionality:** Would these carbon reductions happen anyway, or only because of this project? [32]
- **Permanence:** Will the reductions last for the project's full lifespan? [32]
- **Leakage:** What are the positive or negative impacts of potential leakage of fuels or stored carbon on surrounding communities and global greenhouse gas emissions? [31]
- **Monitoring, Reporting and Verification:** Does the project contract with accredited third-party verifiers meeting ISO 14065 standards [33] and with sector-specific expertise and no conflicts of interest?

3. Economic Viability

Technology costs vary significantly. Permitting complexity, external uncertainties (e.g., supply chains), workforce needs, maintenance costs, and other considerations must also be considered in assessing overall costs. It is vitally important to assess the potential cost of both carbon reductions and resulting energy. The term for cost of carbon reduction is **carbon abatement cost** or cost per ton of carbon emissions. **Techno-economic analysis** can be used to determine the approximate cost of electricity production. Some considerations include:

- Large, combined cycle plants require industrial zoning and major transmission infrastructure.
- Permitting complexity increases with plant size and the number of integrated technologies.
- Interconnection approval processes are severely backlogged.
- Larger projects face more complex interconnection studies.
- Supply chain bottlenecks (especially for large transformers) are causing delays.

Considering how to avoid stranded assets as new technologies come online or fuel supply changes is also important. Fuel-flexible combined cycle plants that could run on natural gas, hydrogen, or biogas cost more than standard designs and require careful attention to inter-operability but could offer flexibility in the face of changes in fuel supply.

4. Technology Readiness

Technologies range from fully commercial at Technology Readiness Level (TRL) 9 to early development TRL 3-4. Higher TRL means lower technical risk, but not necessarily lower cost.

Commercially Ready (TRL 9):	*Developing (TRL 3-8):*
• Steam methane reforming • Combined cycle plants • CO_2 absorption with chemical solvents • Post-combustion carbon capture	• Methane pyrolysis (TRL 3-8) • Dry methane reforming (TRL 4-6) • Basalt CO_2 storage (TRL 6-7)

5. Community Impacts

How does the project affect the broader community? Does it provide jobs, energy resilience, or other benefits? Are there any risks to the community, and have they been appropriately mitigated?

Conclusion: Evaluating Tradeoffs

When assessing the trade-offs of natural gas projects, key tradeoffs need to be considered. Some considerations include:

- **For maximum carbon reduction:** Combined cycle with 95% carbon capture achieves deep emissions cuts but costs triple that of standard plants and reduces efficiency.
- **For fastest deployment:** Standard combined cycle plants are proven, relatively affordable, and can be built within 3 years, but produce significant CO_2 emissions without capture.
- **For future flexibility:** Fuel-flexible combined cycle plants cost more than standard designs but can transition to hydrogen or biogas as these fuels become available.

The optimal approach likely involves a portfolio strategy—using different technologies for different applications based on siting opportunities, grid needs, and available budgets—while ensuring robust monitoring and verification of carbon reduction claims.

BACKGROUND

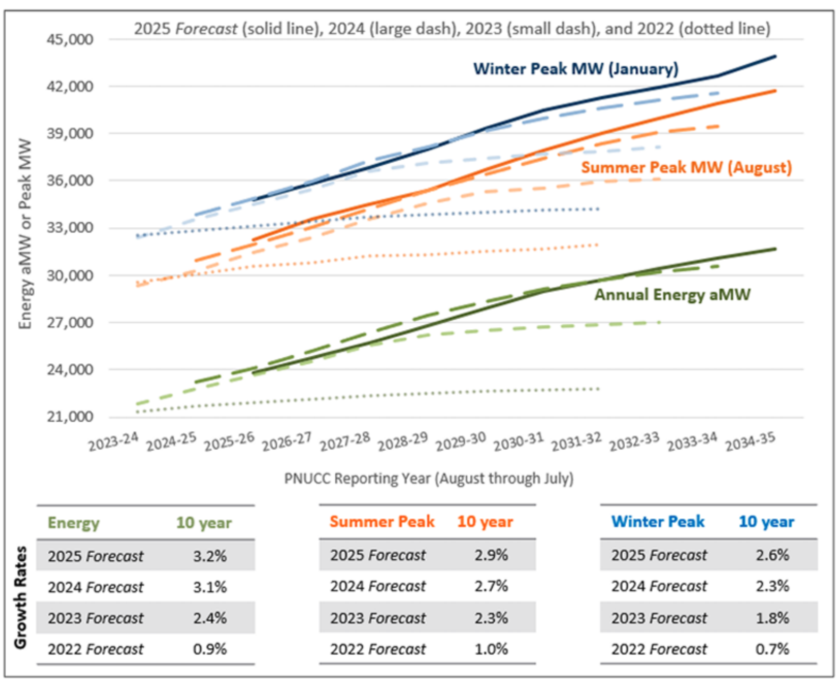
Electricity Demand Forecasts and Fuel Mix

Electric grids in Washington and the Pacific Northwest are experiencing unprecedented growth in loads driven by electrification of new systems, such as transportation and heating systems, and new large loads, such as advanced manufacturing facilities and data centers. Figure 1 from the Pacific Northwest Utilities Conference Committee's (PNUCC) 2025 Northwest Regional Forecast Report [1] highlights the forecasted load growth and demonstrates how forecasts have evolved over the last four years. While the Pacific Northwest has typically had a winter peaking electric load (35,500 MW in 2024), utilities have recently seen summer load growth (33,000 MW in 2024) with peaks approaching similar winter peak levels [1, 2]. Washington State accounts for the majority of that load growth, with about 56% of the installed generation capacity of all utilities represented in the Pacific Northwest Utilities Conference Committee report. The PNUCC footprint extends to Washington, Oregon, Idaho, Montana west of the Continental Divide, and portions of Nevada, Utah, and Wyoming.

According to PNUCC projections, additional capacity additions would increase the existing 57 GW (2025) by 30 GW within the next 10 years through some combination of energy generation technologies [1]. As shown in Table 1, natural gas-fueled generators (combined cycle and combustion turbines) represent 13% of total current generation resources [3].

Figure 1: Projected Load Growth

Source: PNUCC 2025 Northwest Regional Forecast Report [1]



The solid lines represent the 2025 load forecast, while the lighter dashed lines depict previous years' forecasts. The annual energy projections shown in green suggest that regional loads could grow by approximately 7,800 average megawatts (aMW) over the next decade—an increase of more than 30%. The data starts at around 23,800 aMW in 2025 and rises to roughly 31,600 aMW by 2034.

Table 1: Washington State Electric Generation Capacity in 2024

Source: Energy Information Administration [3]

Generation source	Megawatts	% of total
Coal	730	2%
natural gas	4,045	13%
Nuclear	1,200	4%
wood/landfill gas/ municipal waste	302	1%
Hydro	21,409	68%
Solar	268	1%
Wind	3,387	11%
Storage	320	1%
Total	**31,661**	

Electric Grid Flexibility and Stability

The amount of energy produced and consumed must be kept in balance in real time to maintain grid function and prevent outages. One downside of renewable resources like solar and wind is that they cannot be adjusted by controllers to match energy supply with demand. For instance, peak solar generation at midday does not align with peak electricity demand on winter evenings. Washington and the Pacific Northwest have significant hydroelectric generation capabilities, but due to changing snowpack melting patterns and competing water uses, hydroelectric generation availability has declined in July and August during summer peak electric load times [2].

With increasing load and variable solar, wind, and hydroelectric power generation, there is an increased need for electricity generation that can be dispatched on demand to maintain the reliability and resilience of the power grid.

While evolving technologies such as small modular reactors and fusion offer future solutions, the timeline for implementation of these technologies will not match growing demand in the short term. New generation facilities face significant state and federal regulations and policies that create long timelines (depending on generation type) for construction and grid connection. To meet forecasted load growth, it will be necessary to deploy existing dispatchable generation technologies, which include energy storage (e.g., batteries or pumped hydro) or power plants powered by geothermal energy, hydrogen, biomass, nuclear, or natural gas [11].

The remainder of this review focuses exclusively on technologies for converting natural gas to electricity and opportunities to minimize carbon emissions from this process.

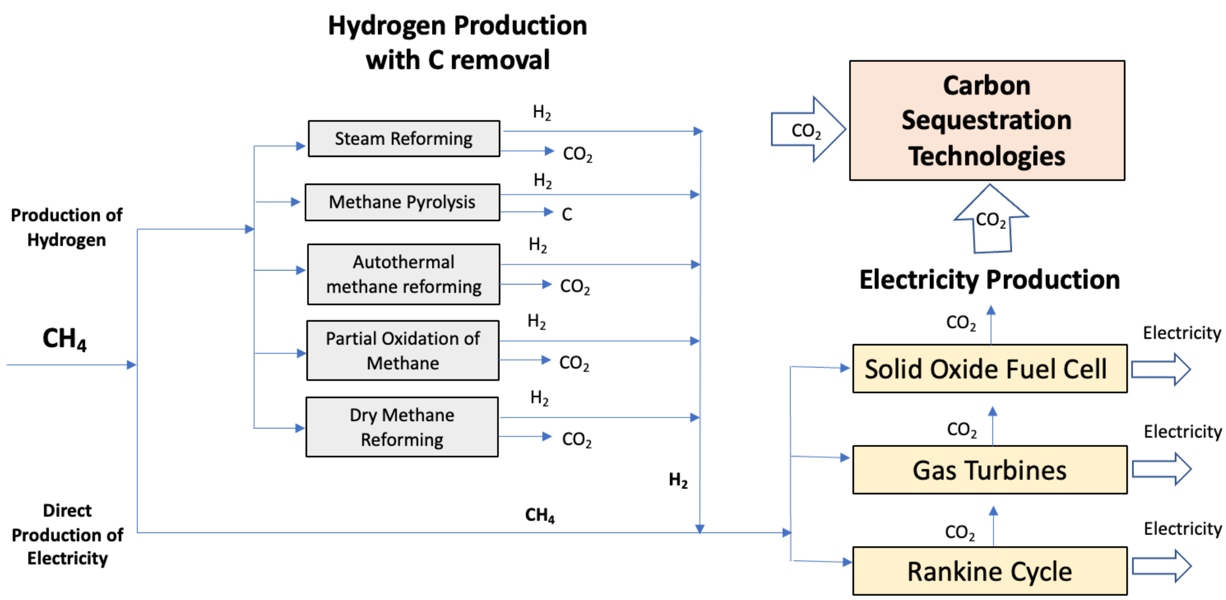
OVERVIEW: NATURAL GAS FOR ELECTRICITY PRODUCTION

Natural gas is essentially methane (CH_4), which may be converted directly to electricity through combustion or converted into hydrogen fuel, which can be used for many purposes including electricity production.

The preferred pathway to electricity production depends on needs and site characteristics. Producing electricity via the hydrogen pathway requires about 20-40% more natural gas to produce the same amount of electricity and produces the same amount or slightly more CO_2 per kWh [15, 17, 22]. Therefore, if the goal is to produce as much electricity as possible for the lowest cost and emissions, direct combustion is usually preferable. However, if hydrogen is already being produced on-site for other purposes, it can be a valuable component of a power plant. Benefits of hydrogen turbines include faster ramp-up time than natural gas, providing greater flexibility during peak times; fuel redundancy in case of supply or price spikes; and the opportunity to locate energy generation away from the gas source. Some advanced turbines can burn both fuels in the same turbine at varying blend ratios, providing even more flexibility [13].

Figure 2 and the following text describe the most common technologies for both conversion of natural gas to hydrogen and direct conversion to electricity. Both processes produce CO_2, which if not sequestered, will contribute to greenhouse gas emissions.

Figure 2: Summary of the Most Common Uses of Natural Gas for Energy Production



Designing a system that balances site needs, grid needs, carbon reduction, cost, and reliability depends on numerous factors. Sections 1-2 below describe common pre-combustion (hydrogen) and direct combustion technologies. Section 3 reviews carbon separation technologies, and Section 4 reviews carbon storage and reuse.

SECTION 1: Pre-Combustion Hydrogen Generation Technologies

Pre-combustion technologies use natural gas (CH_4) as input and chemically separate it into hydrogen (H_2) and CO_2. The principal technologies are shown in Figure 2 and described below.

Steam Methane Reforming (SMR) is a chemical process used to produce hydrogen by reacting methane (CH_4) with steam (H_2O) at high temperatures (700-1,100°C) in the presence of a nickel-based catalyst. Advantages of SMR include maturity of the technology, relatively low cost, and scalability, making it the dominant hydrogen production method today. Disadvantages include high energy demand and large CO_2 emissions unless coupled with carbon capture and storage (CCS) [6].

Methane Pyrolysis is a thermochemical process that decomposes methane (CH_4) into hydrogen gas (H_2) and solid carbon (C) at high temperatures (typically 800-1,200°C) in the absence of oxygen and without the use of water. Unlike steam reforming, it does not produce carbon dioxide (CO_2) as a byproduct. The only input is methane (or natural gas), and the main outputs are hydrogen and a solid carbon byproduct. The advantages of methane pyrolysis include its potential for zero CO_2 emissions during hydrogen production, reduced water use, and the ability to store or use solid carbon in materials or construction. Its key disadvantages are technical immaturity, high process temperatures, the need to manage or find markets for large volumes of solid carbon, and higher capital costs compared to conventional hydrogen production routes like steam methane reforming [35].

Autothermal Methane Reforming (ATR) is a process that produces hydrogen-rich syngas by combining partial oxidation and steam reforming of methane (CH_4) in a single reactor. The inputs are methane, steam (H_2O), and a controlled amount of oxygen (O_2) or air. The oxidation of methane releases heat, which drives the endothermic steam reforming reaction, making the process thermally self-sustaining. The main outputs are hydrogen (H_2), carbon monoxide (CO), and carbon dioxide (CO_2). Advantages of ATR include better thermal integration, higher hydrogen yield per unit of methane, and easier integration with carbon capture and storage (CCS) due to a more concentrated CO_2 stream compared to steam methane reforming. Disadvantages include the need for oxygen production, which adds cost and complexity, and the generation of CO_2 emissions (unless paired with CCS) [12].

Partial Oxidation of Methane (POM) is a high-temperature process in which methane (CH_4) reacts with a limited supply of oxygen (O_2)—less than what is needed for complete combustion—to produce a hydrogen-rich syngas mixture of hydrogen (H_2) and carbon monoxide (CO). The reaction is exothermic, meaning it releases heat, which makes it faster and more compact than steam methane reforming. The main inputs are methane and oxygen (or air), and the outputs are H_2, CO, and small amounts of CO_2 and water. Advantages include rapid reaction rates, simpler reactor design due to the self-heating nature of the process, and suitability for integration with downstream processes to produce fuels or other products. Disadvantages include lower hydrogen yield compared to steam reforming, generation of CO_2, and the need for an oxygen supply, which increases operational costs if pure O_2 is required [12].

Dry Methane Reforming (DMR) is a thermochemical process that converts methane (CH_4) and carbon dioxide (CO_2) into syngas, a mixture of hydrogen (H_2) and carbon monoxide (CO), through an endothermic reaction that occurs at high temperatures (typically 800-1,000°C) over a metal catalyst. The inputs are methane and CO_2, and the outputs are syngas (H_2 and CO), with an H_2:CO ratio typically close to 1:1. Though DMR is less commonly deployed, advantages of include the simultaneous utilization of two greenhouse gases, making it attractive for carbon mitigation, and the production of a syngas ratio well-suited for downstream processes like fuel or methanol production. Disadvantages include high energy demand due to the endothermic nature of the reaction, carbon deposits that reduce function and increase maintenance needs, and the need for precise temperature and feedstock control to maintain stable operation [37].

SECTION 2: Combustion of Natural Gas for Electricity

Figure 2 above lists the major technologies for converting methane directly into electricity, which are described in more detail below and in a 2022 report from the National Energy Technology Laboratory [12].

Turbines:

- **Combustion Turbine** (or gas turbine) generates electricity by burning a fuel—typically natural gas, jet fuel, or diesel—with compressed air to produce high-temperature, high-pressure combustion gases that spin a turbine connected to a generator. The main inputs are fuel and air, and the outputs are electricity, hot exhaust gases, and CO_2 emissions. Advantages include fast start-up, high power density, and suitability for peaking power or use in combined cycle plants for improved efficiency. Disadvantages include lower efficiency when operated alone (simple cycle), high CO_2 emissions from fossil fuels, and performance sensitivity to ambient temperature.

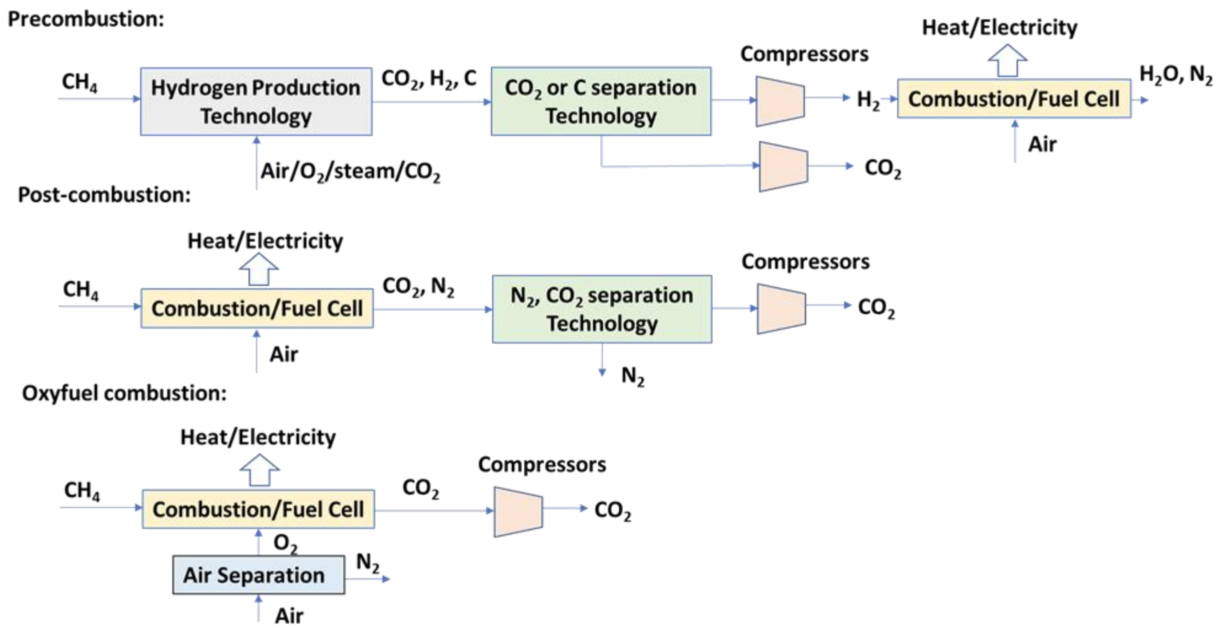
- **Combined Cycle Power Plant** generates electricity by integrating a gas turbine (combustion turbine) and a steam turbine to improve overall efficiency. First, natural gas (or another fuel) is burned in a gas turbine to produce electricity and hot exhaust gases; these exhaust gases are then used to produce steam in a heat recovery steam generator (HRSG), which drives a steam turbine to generate additional electricity. The main inputs are fuel and air, and the outputs are electricity and CO_2 emissions. Advantages include high efficiency (up to ~60%), lower fuel use per kWh, and lower emissions per unit of power compared to simple-cycle plants. Disadvantages include higher capital costs, longer start-up times, and reduced flexibility to ramp up and down compared to standalone gas turbines. Reduced flexibility is caused by the goal to maintain high efficiency and to avoid thermal cycling of the steam cycle.

Fuel Cell Technologies:

- **Hydrogen/Natural Gas Fuel Cell** generates electricity through an electrochemical reaction between hydrogen (H_2) or CH_4 and oxygen (O_2), without combustion. In the most common type (proton exchange membrane, or PEM fuel cell), hydrogen is split into protons and electrons at the anode; the electrons flow through an external circuit (producing electricity), while protons pass through the membrane to the cathode, where they combine with oxygen to form water (H_2O). The main inputs are hydrogen and air (oxygen), and the outputs are electricity, water, and a small amount of heat. Advantages include zero emissions at the point of use, high efficiency, and quiet operation. Disadvantages include high cost, limited hydrogen infrastructure, and challenges with hydrogen production, storage, and transport, especially if not sourced from low-carbon processes.
- **Solid Oxide Fuel Cell (SOFC)** generates electricity through a high-temperature electrochemical reaction using a ceramic electrolyte that conducts oxygen ions (O^{2-}). Operating at 600-1,000°C, it typically uses hydrogen, carbon monoxide, or hydrocarbon fuels (like natural gas) as the fuel and oxygen (from air) as the oxidant. Oxygen ions move through the solid electrolyte to the anode, where they react with the fuel to produce electricity, heat, and water (H_2O) or CO_2 depending on the fuel used. Advantages include high efficiency, fuel flexibility, and potential for combined heat and power (CHP). Disadvantages are slow start-up, high operating temperatures (which stress materials), and high system cost, which limits widespread adoption.

SECTION 3: Carbon Separation

Figure 3: Approaches Proposed for Production of Heat/Electricity from Natural Gas (CH_4) with CO_2 Separation



All approaches result in the production of heat/electricity, a stream rich in CO_2, and a stream rich in N_2. Each has advantages and disadvantages, which are summarized in Tables 2 and 3 [7, 36].

Table 2: Pros and Cons of Pre-Combustion Capture [7]

Advantages/Opportunities	**Disadvantage/challenges**
Used by the industry for over 95 years	Expensive in terms of capital cost and equipment
Low emissions of CO_2 (92-93 % recovery)	Significant energy loss compared with post-combustion. Improvements needed on energy recovery efficiency
Enhanced energy efficiency in separation and compression resulting in decreased gas volume	Complex chemical processes may lead to plant shutdowns
Low regeneration energy due to use of solvents for CO_2 separation (mature adsorption and absorption technologies)	Cooling the syngas to CO_2 capture is necessary
Use less water	Efficiency loss in the water-gas shift section

Some of the companies that have implemented pre-combustion capture include: Saudi Aramco (2018), North

West Redwater (2011), Occidental Petroleum (2010), Western Australia Department of Mines and Petroleum (2009), Anadarko Petroleum Corporation (2006), Shenhua Coal Trading (2000), Cenovus Energy (2000), MCN Energy Group (1998), Shaanxi Yanchang Petroleum Group (2017), ELCOGAS S.A. (2011), CO_2CRC (2009), Petrobras (2009), and Tampa Electric Power Company (2008).

Table 3: Pros and Cons of Post-Combustion Capture [36]

Advantages/Opportunities	**Disadvantage/challenges**
Suitable for integration with both existing and new energy plants	Low CO_2 concentration at standard atmospheric conditions requiring larger equipment and incurring in additional costs
Modify current designs of power plants for retrofitting	Challenging design of systems that handle flue gases at high temperature and low CO_2 partial pressure
Higher heat and electricity efficiencies compared with pre-combustion	Sensitivity to impurities such as NO_x and SO_x in the adsorption process

Some of the companies using post-combustion CO_2 removal include: China National Petroleum Company (Amines) (2018), Korean Electric Power Corporation (Amines) (2018), CO_2 Solutions Inc. (aqueous alkali salts with enzymes) (2015), SaskPower (amines) (2014), NRG Energy Inc./Petra Nova (solvents) (2010), Indian Farmers Fertilisers Cooperative, Limited (amines) (2006), and Carbon Dioxide Technology Corporation (Amines) (1982).

SECTION 4: Carbon Storage and Sequestration Technologies

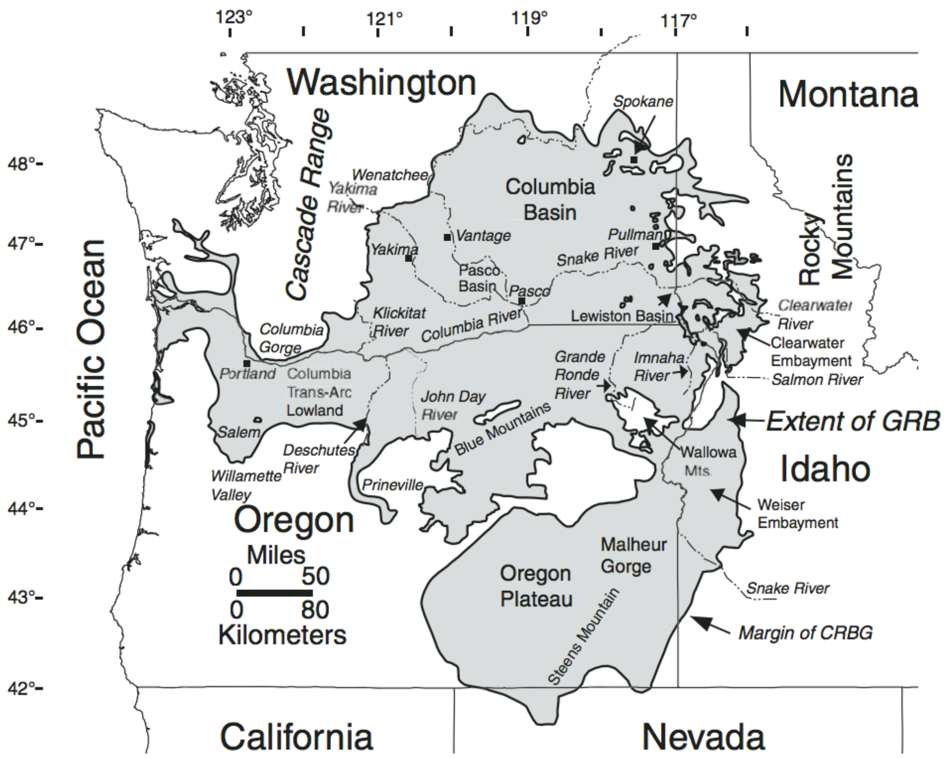
Carbon can be stored in the earth or reused in products like building materials, fuels, chemicals, or carbonated drinks.

Carbon reuse is still limited by scale, given that a single 500 MW natural gas plant produces about 1-2 million tons of CO_2 per year [4], and current global markets for CO_2-based products are only around 230 million tons annually [9]. However, these products can create a revenue stream to offset the costs of separation and storage.

Identifying suitable geologic carbon storage solutions requires not only the right type of geology, but also the space to contain large amounts of compressed CO_2, sufficient transport and injection of CO_2 to depths required for stable storage, the ability to confine CO_2 safely, and continuous monitoring to ensure safety [30]. Suitable storage areas can be found in saline formations, oil and natural gas reservoirs, unmineable coal seams, organic-rich shales, sandstone, and basalt formations [27]. Basalt lava formations in central and eastern Washington are particularly well-suited for permanent CO_2 storage in rock. Figure 4 shows the Columbia River Basalt Group. A pilot project successfully injected 1,000 tons of CO_2 into basalt, 60% of which mineralized within three years [28]. The predicted potential of storage capacity of this region is upward of 40 gigatons [38]. Potential disadvantages of geologic storage are high capital costs and project timelines, and risks associated with increased underground pressure or CO_2 leakage that could lead to increased seismicity or push contaminants into groundwater [31].

Figure 4: Columbia River Basalt Group

Source: U.S. Geological Survey [29]



Map shows main regions of basalt exposure in Washington, Oregon, Idaho, and Nevada

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CARBON EMISSIONS PROFILES

Baseline Carbon Emissions by Technology

Understanding the carbon footprint of each technology is essential for evaluating decarbonization strategies. Table 4 compares emissions across all technologies using kilograms of CO_2 per megawatt-hour of electricity delivered, allowing direct comparison between combustion and hydrogen-based pathways.

Table 4: Carbon Emissions by Technology [12-25]

Technology Pathway	CO_2 Emissions kg CO_2e/MWh-net	Notes
Direct Combustion		
Natural gas simple cycle turbine	500-600	Lower efficiency; used for peaking power

Natural gas combined cycle turbine	350-400	Most efficient fossil fuel option
Combined cycle w/ 95% capture	40-60	Best environmental performance but significant efficiency/cost penalty from capture process
Hydrogen Production + Electricity Generation		Assumes 9-12 kg CO_2/kg H_2 and typical turbine efficiency of 45% and fuel cell efficiency of 60%
H_2 from SMR (no capture) → fuel cell	450-600	
H_2 from SMR (no capture) → combustion turbine	600-800	
H_2 from SMR w/ 85% capture → combustion turbine	90-120	
H_2 from methane pyrolysis → combustion turbine	150-250	Range depends on energy source and carbon storage
Reference Points		
Coal-fired power plant	800-1,000	Baseline for comparison
U.S. grid average (2023)	370	Mix of all generation sources
Nuclear power	10-15	Life cycle emissions only
Wind/solar power	10-40	Life cycle emissions from manufacturing

Key Insights:

- Natural gas combined cycle turbines without capture have similar carbon emissions as the current U.S. grid average [22].
- Combined cycle with 95% carbon capture (~30 kg CO_2/MWh) achieves emissions comparable to nuclear and renewables.
- Conversion of natural gas to Hydrogen using common methods produces similar or slightly more CO_2 than direct combustion Hydrogen pathways.

CONSIDERATIONS FOR PROJECT DESIGN AND REVIEW

There are many considerations in choosing the appropriate energy generation and carbon reduction technologies. The following assessments will help designers and regulators consider:

1. What is the carbon footprint of this project vs. other options for the amount of energy generated?

2. What are the costs of this project vs. alternatives, and are they economically viable?

3. What is the technology readiness level of the technologies included in the project, and what more must be done to validate or scale them up?

4. What are additional complexities or risks that would need to be mitigated for a project to be successfully deployed?

The UN Framework Convention on Climate Change (UNFCCC) has developed a Methodological Tool to aid entities in assessing the viability of greenhouse gas (GHG) reduction projects [32]. Embedded in this tool are several technical concepts that aid investment. These considerations are grouped below in four categories: Carbon Reductions, Economics, Technical Readiness, and Project Complexity.

Carbon Reduction Assessment

The estimated emissions in Table 4 are based on published studies that look at the emissions over the life cycle of the technologies listed. **Life Cycle Assessment** tools evaluate lifetime carbon emissions of, including raw material extraction, manufacturing, transportation, and use. For example, the US Department of Energy tool called GREET can be used to calculate the following for any energy or transportation system [21]:

- Total energy consumption (non-renewable and renewable)
- Fossil fuel energy use (petroleum, natural gas, coal)
- Greenhouse gas emissions
- Air pollutant emissions
- Water consumption

To understand the value of any proposed project to reduce GHG emissions, it is crucial to consider **Additionality**, to ensure that the carbon reductions are real and would not occur without the proposed project or intervention. This assessment begins by determining the **common practice** and comparing the carbon intensity of this to that of the proposed project. For electricity production, common practice could be direct combustion of natural gas or purchase of market electricity to fulfill unmet demands. It is also important to assess the **Permanence** of the proposed reductions by ensuring the project will reach its proposed duration The potential impacts of leakage CO_2 **Leakage** must be assessed – whether underground leakages that could affect groundwater or seismicity or atmospheric leakage that contributes to global emissions. Finally, any project should develop a **Measurement, Reporting, and Verification plan** that is implemented by a credible third party adhering to International Standards Organization's 14065 standards [33].

Economic Assessment

It is vitally important to assess the potential cost of both carbon reductions and resulting energy. The term for cost of carbon reduction is **carbon abatement cost** or cost per ton of carbon emissions. **Techno-economic analysis** can be used to determine the approximate cost of electricity production. This is a common practice by corporations and is used to determine the economic viability of any new technology or project. In early evaluation stages, a ±30% assessment can be conducted.

Table 5 below shows estimated costs and performance characteristics for power plant costs from the U.S.

Energy Information Administration (EIA).

Table 5: Estimated Costs of Energy Generation Resources [10, 12]

Technology	First Avail. Year	Unit Size (MW)	Lead Time (years)	Overnight Cost 2024 $/kW	Variable O&M 2024 $/MWh	Fixed O&M 2024 $/kW-y	Heat Rate BTU/kWh
Comb. Cycle	2027	617	3	875	3.39	15.75	6,226
Comb. Cycle w/ 95% CCS	2028	543	4	2,469	5.13	27.15	7,279
Fuel Cell	2027	10	3	7,896	0.70	36.67	6,469
Hydrogen Turbine	2026	237	2	823	5.36	8.24	8,295

Technology Readiness Assessment

When selecting the appropriate technologies or combination of technologies, it is important to answer the following questions:

1. What is the technology readiness level (TRL) of all the components of the technologies studied? TRLs range from 1 (basic principles observed) to 9 (full readiness for large-scale deployment). Table 6 shows the TRL for selected technologies relevant to the decarbonization of natural gas conversion.
2. Can the technology provider certify the operation of the processes proposed?
3. What is the minimum selling price of kWh of electricity in all the technologically viable concepts?
4. What is the carbon intensity per kWh of electricity produced for each of the potential concepts?
5. What is the CO_2 abatement cost for each of the technological concepts studied?

The best option will depend on the business model and the incentives available.

Table 6: Technology Readiness Level (TRL) for Selected Technologies

Technology	TRL	Prominent Projects
CO_2 absorption with Amines	9	Units operated by Saudi Aramco, Occidental Petroleum
CO_2 absorption with Rectisol	9	Units operated by North West Redwater
Amines + Membranes	9	Anadarko Petroleum Corporation
Amine + Ammonia + Membranes	6-7	CO_2CRC
MTR Membranes	6-7	Petrobras

Aqueous Alkali Salts with Enzymes	8-9	CO_2 Solutions, Inc.
Steam Methane Reforming	9	Air Liquide, Linde, Air Products and Chemicals Inc.
Partial Oxidation of Methane	9	Clariant Ltd
Autothermal Methane Steam Reforming	9	Air Liquide
Methane Pyrolysis	3-8	Monolith, Hazer, Hycamite, Tulum Energy
Dry Methane Reforming	4-6	Linde
Basalt CO_2 Storage	6-7	CarbFix, Carbon TrapRock Project

Adaptability Considerations

Adaptability of power plants is important from three aspects: (1) siting and placement of plant, (2) feedstock diversity and fuel, and (3) operational flexibility to meet grid demands.

Siting of Power Plants: Large power plants with large noise emissions and large power outputs require industrial zoned sites. Smaller power plants, such as fuel cells, that are quiet with only water vapor as exhaust could be sited in residential and commercially zoned areas. They also would not require access to sufficient transmission lines because of their relatively small power output (<20 MW).

Fuel Diversity: Combined cycle technologies use combustion turbines, which allow for a wide range of fuels to be combusted. While designed for natural gas, combined cycle technologies can also be fueled by biogas, low-sulfur fuel oil, landfill gases, and even hydrogen. Fuel cell technologies require hydrogen. They are highly sensitive to hydrogen impurity, causing performance degradation and equipment damage. Hydrogen turbines can operate with less pure hydrogen and are less sensitive to hydrogen impurity.

Operational Flexibility: Ramping capability becomes more important with high contributions in the generation mix of wind and solar generation capacity. Fuel cell technologies have demonstrated good ramping capabilities, ramping up within seconds. Combined cycle technologies are theoretically able to ramp but at the expense of efficiency degradation.

Permitting and Grid Interconnection Considerations

Permitting: How resource-intensive are the technologies considered with respect to fuels, water, and air, and which jurisdictions need to review the permit request? What are the uncertainties and risks associated with future fuel pricing and decommissioning processes? What is the complexity of the project and the number of different technologies involved?

Grid Interconnection: Utilities and transmission owners cannot keep up with the multitude of power plant and transmission expansion requests. Furthermore, supply chain bottlenecks, especially of large transformers, have slowed down the entire construction timeline. In general, the larger the project (MW), the more complex the interconnection analysis will be, which may cause further delays in the interconnection approval processes. Smaller projects tend to have less complex interconnection requirements.

SELECTED RESOURCES IN WASHINGTON

- **Institute for Northwest Energy Futures** at Washington State University
  https://wsuwp.tricities.wsu.edu/inef/
- **Carbon Storage Program** at Pacific Northwest National Laboratory
  https://www.pnnl.gov/carbon-storage
- **Bioenergy and Bioproducts Engineering** at Washington State University
  https://bsyse.wsu.edu/research/bioenergy/

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