

Assessment of Nuclear Energy to Support Negative Emission Technologies

Nuclear Fuel Cycle and Supply Chain

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SUMMARY

The feasibility and performance of nuclear energy coupled with Negative Emission Technology (NET) processes were investigated in this report. Three overarching questions from nuclear NET systems guided this research: which NET would be able to use heat and/or electricity from nuclear power plants (NPPs); what is the performance and cost of a nuclear NET system; and what would be the market outlook for this system?

Among the various NETs that are actively being developed, several were found to potentially benefit from coupling with an NPP via (1) large amounts of decarbonized and constant-output electricity; (2) free waste heat or cheap low-temperature heat; or (3) high-temperature heat. NPPs were found to be compatible with Direct Air Capture (DAC) systems, and a detailed techno-economic analysis of coupled NPP&DAC systems was performed. Preliminary analysis also indicated that biomass and water-based NETs are potentially compatible with NPPs, but further work is needed to quantify the performance of these nuclear NET systems.

Design and performance analyses were completed for both liquid solvent DAC (L-DAC) and solid sorbent DAC (S-DAC) technologies. A 1.0-GWth NPP coupled with L-DAC and S-DAC was found to be able to capture 12–15 Mt CO₂/yr and 1.0–1.5 Mt CO₂/yr, respectively. While the L-DAC process enables much greater CO₂ capture than the S-DAC process when both are sized with a 1 GWth NPP, the NPP&L-DAC system considered also requires >2 GWth natural gas oxy-combustion to reach adequate temperature in the calciner. CO₂ generated from natural gas combustion is also captured as part of the calcination process, in addition to the CO₂ captured from air, resulting in overall CO₂ sequestration of close to 30% more than what is captured from air. The cost of carbon capture calculated with the levelized cost of DAC (LCOD) had a range of \$170–260/tCO₂ for NPP&L-DAC systems and a range of \$650–680/tCO₂ for NPP&S-DAC systems. For both DAC systems, the NPP provides economic benefit when compared to previous National Energy Technology Laboratory (NETL) studies of non-nuclear DAC systems, leading to reduction of LCOD by 5–7% for L-DAC, and 8–13% for S-DAC.

For the NPP&DAC systems, a preliminary market analysis reviewed potential CO₂ market prices and eligibility for incentives. The estimated potential revenues for CO₂ capture (coming from federal incentive, CO₂ commodity markets, or offset market) is in the range of \$170–979 tCO₂, and the results show that because of lower LCOD, the NPP&L-DAC process would be more attractive to a market than the NPP&S-DAC process. The large investment needed for NPP&DAC processes would require long-term certainty of sufficient market size, CO₂ prices, and incentives. Enabling NPPs to ramp DAC operation up or down based on electricity market price is not expected to significantly increase revenues of the NPP&DAC system. This is because the revenues from CO₂ sequestration are required to be very high to justify the deployment and continuous operation of the very expensive DAC technologies.

In this analysis, several new research questions were uncovered, and follow-up analyses are recommended for further investigation, including a detailed feasibility study of NPP coupled with other NET systems such as biomass pyrolysis and gasification with carbon capture and storage, and seawater carbon capture.

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ACRONYMS

ANL	Argonne National Laboratory
ASU	Air separation unit
BECCS	Bioenergy with carbon capture and storage
BOP	Balance of plant
BPMED	Bipolar membrane electrodialysis
CDR	Carbon dioxide removal
DAC	Direct Air Capture
DACCS	Direct Air Capture and Carbon Sequestration
DIC	Dissolved inorganic carbon
DOE	U.S. Department of Energy
EEW	Engineered EW
EOR	Enhanced Oil Recovery
ERCOT	Electric Reliability Council of Texas
ESA	Electro-swing absorption
EW	Enhanced Weathering
FOM	Fixed O&M
FT	Fisher-Tropsch
HHV	Higher heating value
HPT	High-pressure turbine
HX	Heat exchanger
IEA	International Energy Agency
INL	Idaho National Laboratory
IPCC	Intergovernmental Panel on Climate Change
IRA	Inflation Reduction Act
ISC	Indirect seawater capture
LCFS	Low Carbon Fuel Standard
LCOD	Levelized cost of DAC
LCOE	Levelized cost of electricity
L-DAC	Liquid Solvent DAC
LPT	Low-pressure turbine
m-DAC	Membrane-based DAC
NE	Office of Nuclear Energy
NET	Negative Emission Technology

NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NPP	Nuclear power plant
O&M	Operation and Maintenance
OCC	Overnight capital cost
PBC	Packed bubble column
PDC	Plant Dynamics Code
PWR	Pressurized Water Reactor
PyCCS	Pyrogenic application to Carbon Capture and Storage
SA&I	Systems Analysis & Integration
S-DAC	Solid Sorbent DAC
SFR	Sodium-cooled Fast Reactor
SG	Steam generator
SMR	Small Modular Reactor
TRL	Technology readiness level
VHTR	Very High Temperature Reactor
VOM	Variable O&M
VRE	Variable Renewable Energy

SYSTEMS ANALYSIS AND INTEGRATION CAMPAIGN ASSESSMENT OF NUCLEAR ENERGY TO SUPPORT NEGATIVE EMISSION TECHNOLOGIES

1. INTRODUCTION

The Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment report suggests that up to 390 Gt of cumulative atmospheric CO₂ will need to be removed by 2100 to limit warming to 2 °C, and up to 680 Gt to limit warming to 1.5 °C [1]. Further, “*The deployment of carbon dioxide removal (CDR) to counterbalance hard-to-abate residual emissions is unavoidable if net zero CO₂ or GHG emissions are to be achieved. The scale and timing of deployment will depend on the trajectories of gross emission reductions in different sectors. Upscaling the deployment of CDR depends on developing effective approaches to address feasibility and sustainability constraints especially at large scales. (high confidence)*” [2]. Removal of CO₂ from the atmosphere using Negative Emission Technologies (NETs) will have an important role to play in compensating for residual carbon emissions from sectors recognized as being difficult to decarbonize, such as transportation by aviation, shipping, and agriculture, and help the world achieve net zero emissions. The U.S. administration is renewing and increasing incentives for NETs with increased tax credits (under U.S. Tax Code Section 45Q) as part of the 2022 Inflation Reduction Act (IRA) [3].

Nuclear energy is already playing an important role in decarbonizing the electricity sector (an ~1 GWe nuclear power plant (NPP) connected to the grid avoids emission of ~2.7 Mton CO₂/yr¹), and can play an even larger role in decarbonizing other sectors of the economy through hydrogen production (providing heat and electricity), high-temperature heat production for industrial applications, district heating, etc. Another barely considered opportunity for nuclear energy to contribute to decarbonization is to couple it with NET: nuclear power generates heat and/or electricity that can be used in various NETs to remove CO₂ from the atmosphere. The scale and speed of NET deployment will be driven by the readiness and costs of the technologies. It is currently expected that the costs of large-scale CO₂ removal will need to decrease to enable wide deployment of NETs; therefore, DOE recently launched the Carbon Negative Shot initiative, which targets prices as low as \$100/tCO₂ [4]

As discussed in this report, nuclear energy can support CO₂ capture and sequestration technologies because of NPPs’ ability to generate large quantities of decarbonized and constant-output electricity and heat. Nuclear energy coupled with a NET system is also referred as nuclear NET in this report. Thus, the U.S. Department of Energy (DOE) Office of Nuclear Energy (NE) Systems Analysis & Integration (SA&I) campaign jointly with the National Energy Technology Laboratory (NETL) Strategic Systems Analysis and Engineering Directorate have undertaken this study to evaluate the opportunities for nuclear energy to support NETs to remove CO₂ from the atmosphere through assessment of the carbon reduction performance and market feasibility of various nuclear NET systems.

1.1 Brief Introduction to NET Technologies

Various NETs are actively being developed [5], but only the ones that may be compatible with nuclear energy—i.e., those that benefit from a dense source of energy—are considered in this report. Here is a short description of these NETs:

¹ Assuming the NPP would be replaced by a “new” Natural Gas Combined Cycle plant with emissions of 0.34 tCO₂/MWh [6].

- Direct Air Capture (DAC) and Carbon Sequestration (DACCS): [5] “Chemical processes that capture CO₂ from ambient air and concentrate it, so that it can be injected into a storage reservoir.” These NETs are further discussed in Section 2.1.
- Biomass-based Processes: [5] “Energy production using plant biomass to produce electricity, liquid fuels, and/or heat combined with capture and sequestration of any CO₂ produced when using the bioenergy and any remaining biomass carbon that is not in the liquid fuels.” The main NETs in this category are biomass combustion, pyrolysis, and gasification, as further described in Section 2.2.
- Enhanced Weathering (EW): [5] “Accelerated “weathering,” in which CO₂ from the atmosphere forms a chemical bond with a reactive mineral (particularly mantle peridotite, basaltic lava, and other reactive rocks), both at the surface (ex situ), where CO₂ in ambient air is mineralized on exposed rock, and in the subsurface (in situ), where concentrated CO₂ streams are injected into ultramafic and basaltic rocks, where the CO₂ mineralizes in the pores.” EW and other water-based processes are discussed in Section 2.3.

Other NETs were not considered because of their obvious lack of potential for nuclear energy compatibility, such as coastal blue carbon and terrestrial carbon removal and sequestration that rely on land use and management practices to store CO₂ in living plants and in the soil. These NETs would not benefit from the high-density heat and/or electricity that a NPP would provide. Some NETs that have a low Technology Readiness Level (TRL), such as CO₂ capture from seawater, were considered and will be mentioned in this report, but no attempt will be made to be exhaustive, as this is a quickly developing field of research.

The ranges of deployment and technology readiness of NETs mentioned in this section are well summarized in the IPCC 2022 Summary for Policymakers [6]:

“All the illustrative mitigation pathways (IMPs) assessed in this report use land-based biological CDR (primarily afforestation/reforestation (A/R)) and/or bioenergy with carbon capture and storage (BECCS). Some also include direct air CO₂ capture and storage (DACCS) (high confidence). Across the scenarios limiting warming to 2°C (>67%) or below, cumulative volumes² of BECCS reach 328 (168–763) GtCO₂, CO₂ removal from AFOLU (mainly A/R) reaches 252 (20–418) GtCO₂, and DACCS reaches 29 (0–339) GtCO₂, for the 2020–2100 period. Annual volumes in 2050 are 2.75 (0.52–9.45) GtCO₂ yr⁻¹ for BECCS, 2.98 (0.23–6.38) GtCO₂ yr⁻¹ for the CO₂ removal from AFOLU (mainly A/R), and 0.02 (0–1.74) GtCO₂ yr⁻¹ for DACCS.

Despite limited current deployment, estimated mitigation potentials for DACCS, enhanced weathering (EW) and ocean-based CDR methods (including ocean alkalinity enhancement and ocean fertilisation) are moderate to large. (medium confidence). The potential for DACCS (5–40 GtCO₂ yr⁻¹) is limited mainly by requirements for low-carbon energy and by cost (100–300 (full range: 84–386) USD tCO₂⁻¹). DACCS is currently at a medium technology readiness level. EW has the potential to remove 2–4 (full range: <1 to around 100) GtCO₂ yr⁻¹, at costs ranging from 50 to 200 (full range: 24–578) USD tCO₂⁻¹. Ocean-based methods have a combined potential to remove 1–100 GtCO₂ yr⁻¹ at costs of USD40–500 tCO₂⁻¹, but their feasibility is uncertain due to possible side effects on the marine environment. EW and ocean-based methods are currently at a low technology readiness level.”

Consequently, the DACCS and other NET systems are likely going to expand significantly to play a large role in reaching net zero emissions, which would be facilitated through cost reductions as targeted by the DOE Carbon Negative Shot initiative. Powering these NET systems with low-emitting energy such as nuclear energy for cost reduction of CO₂ capture is investigated in this study.

² As a median value [5–95th percentile range].

1.2 Relationship of This Work to Other Work in This Field

Work in this area is emerging, and only a few groups are investigating the coupling of nuclear energy with NETs. Two DOE Office of Fossil Energy and Carbon Management projects were recently awarded funding for DAC front-end engineering design studies:

- Constellation received a \$3.2M award to explore front-end engineering design on a DAC Solvent system for the Illinois Byron nuclear power plant. *“The expected amount of net carbon removed from the atmosphere is 250,000 tonnes/year and the CO₂ captured from the atmosphere will be transported by pipeline to an underground geologic formation in Illinois for permanent storage.”* [7] *“The carbon-removal DAC study at Byron Station will involve Carbon Engineering’s DAC technology, licensed to 1PointFive, within plant operations at the Byron nuclear plant and its twin 495-foot-tall hyperbolic cooling towers. In the proposed study, a chemical solution would be added to water flowing through the facility’s main condenser on the non-nuclear side of the plant. After traveling through the condenser, the water would travel out to the cooling towers, where CO₂ in the air will attach itself to the chemical solution and become captured and sequestered for later use, potentially in industrial processes that will have net zero emissions ranging from creating sustainable aviation fuel to beverage industry (carbonation) production.”* This DAC Solvent technology and coupling to NPP is described further in Section 2.1.1 of this report.
- Battelle Memorial Institute received a \$3.4M award to provide a front-end engineering for DAC Sorbent technology at Southern Company’s Joseph M. Farley Nuclear Plant in Columbia, Alabama. *“The DAC system will be designed to capture at least 5,000 (and up to 20,000) net tonnes of carbon dioxide (CO₂) per year from ambient air. The technology consists of a polymeric amine sorbent on a commercially available monolith contactor substrate to capture CO₂ from ambient air. The two-step temperature vacuum swing adsorption process begins with moving air across an ultra-low pressure drop contactor that adsorbs the CO₂ from the incident air stream, followed by desorption of the CO₂ and regeneration of the sorbent using steam generated from waste heat. Integration of the system with an operational nuclear power plant facility will maximize the use of thermal energy from waste heat at the host nuclear plant. The captured CO₂ will be transported offsite for permanent geologic storage.”* [8] This DAC Sorbent technology and coupling to NPP is described further in Section 2.1.2 of this report.

McQueen et al. reported that combined cycle natural gas-based DAC resulted in the lowest gross CO₂ capture cost when compared to other electricity sources including nuclear energy [9] [10]. In their study, six different electricity sources were considered that provide electricity and thermal energy (electric furnace for calciner) for the liquid-solvent direct air capture (L-DAC) system [9]. The study considered a Pressurized Water Reactor (PWR) and a Small Modular nuclear Reactor (SMR) along with combined-cycle natural gas, wind, solar photovoltaic (with battery) and geothermal sources, and analyzed performance of multiple air flow and its effect on the gross CO₂ removal cost. Another study considered solid sorbent-based direct air capture (S-DAC) with thermal energy from geothermal and nuclear sources. These researchers conducted a detailed cost analysis, based on U.S. geography, for feasibility and cited the importance of financial support for these technologies to reach costs that could lead to mass deployment [10]. Researchers at Oak Ridge National Laboratory have also initiated techno-economic analyses of retrofitting an existing PWR and coupling it with an S-DAC system, with support from a Laboratory Directed Research and Development (LDRD) award [11].

Other recent studies [12] mention the use of biomass and NPP for bio-oil production, with negative emission benefits. However, the focus is more on bio-oil production to decarbonize various sectors of the industry, rather than on negative emissions (which may still be achieved but at a lower rate than considered in this study). A short description of these studies is provided in Appendix A-2.

The following summary provides clarification of what this study aims to research and what was outside its scope:

- This study aims to assess technical compatibility and economic outcomes of various nuclear energy technologies coupled with various types of NETs. Various NETs are reviewed in Section 2 to assess energy needs and potential compatibility with electricity and heat from different NPP technologies. Because the level of readiness of NETs varies drastically and the team had ready access to DAC information, a more detailed techno-economic evaluation was completed on some DAC technologies in Section 4, while only an initial assessment was performed on other NETs (Engineered Enhanced Weathering, or EEW, and Pyrogenic application to Carbon Capture and Storage, or PyCCS), as described in Appendix A.
- Three NPP types are considered in this study. This approach is especially important as advanced nuclear reactor technologies under active development by the U.S. utility industry can offer different conditions in terms of high-temperature heat that could make several NETs compatible and attractive, as discussed in Section 3. The three types of nuclear technologies considered in this report are based on PWR, Sodium-cooled Fast Reactor (SFR), and Very High Temperature Reactor (VHTR) technologies, as those are actively being developed by DOE, including through the Advanced Reactor Deployment Program. The analysis performed in this report on PWRs, SFRs and VHTRs relies on specific reactor information, but the conclusions of this study should be applicable to a wide range of industry reactor concepts.
- In this process, initial market analysis is completed in Section 4.3.2 by assessing levelized cost of carbon capture through NPP&DAC systems to inform the level of CO₂ market price or federal incentives that would be required to make this process economical to a utility. The current incentives for CO₂ capture are described in Appendix B-2. Also discussed is the electricity price that would be required to incentivize flexible operation of the NPP&DAC system with electricity production prioritized over CO₂ capture.
- This study does not intend to extensively compare the wider range of other NET options—associated with energy production from natural gas or Variable Renewable Energy (VRE), for instance—that are also associated with various uncertainty levels and deployment timelines. However, the cost of NPP&DAC systems is compared with that of DAC systems previously studied at NETL relying on electrical grid and natural gas heating [13, 14].
- This study only considers negative emissions achieved with technologies that capture CO₂ from the atmosphere directly or indirectly (as from biomass or the ocean). This work could be extended in the future to consider CO₂ capture from flue gas (coal or natural gas power plants, industries, etc.), which include a wider range of carbon capture technologies.

1.3 Report Organization

In Section 2, a description of various NETs is provided together with discussion of energy needs and feasibility of NPP coupling. The quality and quantity of heat generated by several NPP types to support NET processes are described in Section 3. Detailed techno-economic evaluation is completed on some NPP & DAC systems in Section 4, while more preliminary estimates for some other nuclear NET systems are initiated in Appendix A. Appendix B describes prices of commodities and other source of revenues for nuclear NET systems. Finally, conclusions and observations are discussed in Section 5.

2. REVIEW OF NEGATIVE EMISSION TECHNOLOGIES AND THEIR COMPATIBILITY WITH NUCLEAR ENERGY

Various NETs are actively being developed by the scientific community. This section reviews the NETs that may be compatible with nuclear energy, meaning that they may benefit from a dense source of energy. For each NET considered in this study, a short description is provided together with discussion of its technology deployment status and outlook, and its energy needs. Three main types of NETs are described: DAC in Section 2.1, biomass-based processes in Section 2.2, and water-based processes in Section 2.3. These descriptions are mostly supported by literature review. For each NET, subject matter expertise is used to discuss its potential connections with NPP technologies. The findings of Section 2 will serve as the basis of the selection of specific NETs to consider for more detailed techno-economic analysis in later sections of this report.

2.1 Direct Air Capture (DAC) Technologies

DAC is a key part of the NET landscape and is expected to play an important role in the net zero pathway for many countries by 2050 [15]. DAC is one of the most mature among all the NETs, with a TRL of 6–7 for DAC [16, 6], with a potential to remove 5–40 GtCO₂/yr. systems capture CO₂ from the atmosphere and produce a purified and compressed CO₂ product stream that can be stored in a geologic formation or sold as a commodity. Two main DAC technologies are considered in the literature: the Liquid Solvent (L)-DAC system is described in Section 2.1.1, and the Solid Sorbent (S)-DAC system is described in Section 2.1.2. Other DAC technologies, such as mineralization and electrochemical separation, are not considered in this study. Given the very low concentration of CO₂ in air (~ 400 ppm), DAC requires significant energy input, which is an important factor leading to high cost [5]. Some cost reduction may be achieved using heat and electricity from nuclear energy, as discussed later in this report.

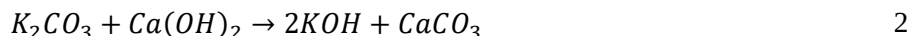
2.1.1 Liquid Solvent DAC

2.1.1.1 Short Description

The solvent technology is usually referred to as Liquid Direct Air Capture (L-DAC). The most developed L-DAC technology relies on a basic solution such as potassium hydroxide (KOH) to capture the CO₂ and regenerate the solvent through a series of operations that typically need operating temperatures between 300 and 900 °C (Figure 2-1) [17]. This process contains two loops, the contactor loop and the calciner loop. In the contactor loop, air is forced through multiple contactors through which KOH flows through packing material; the KOH reacts with CO₂ in the air to form potassium carbonate (K₂CO₃) solution, as shown in Equation 1.



KOH is then recovered in a pellet reactor where the K₂CO₃ solution undergoes an anionic exchange with calcium hydroxide (Ca(OH)₂) to form calcium carbonate (CaCO₃), as shown in Equation 2.



Thus, all the CO₂ captured from air ends up as CaCO₃. The calciner loop is where the Ca(OH)₂ is recovered. First, CaCO₃ is converted to calcium oxide (CaO) and CO₂ at a high temperature (900 °C) in a calciner. CO₂ is purified, compressed and sent to a pipeline for transport. CaO is then converted back to Ca(OH)₂ in contact with steam in a slaker.

2.1.1.2 Potential for Coupling with NPP Technologies

The NPP can couple with L-DAC by providing energy to support its operation in several ways, as shown in Figure 2-1 (the blue lines represent the flow of electricity, the green line represents the flow of atmospheric air, and the black lines represent the flow of captured CO₂):

- Electricity from any NPP technology can be provided to operate the contactor fans, CO₂ compressors and other auxiliary loads of the L-DAC system.
- Heat from any NPP can be used to supply some of the calcination heat in the calciner. The calcination reaction runs at a temperature of around 900 °C to convert CaCO₃ to CaO and CO₂. There are several options for operating the calciner using different types of NPPs as an energy source:
 - An electrically driven high-temperature calciner using electricity coming directly from any NPP technology can be used for the calciner loop [18]. However, electrically powered calciners are yet to be widely deployed in commercial applications, particularly in the size ranges that are likely required for NPP&DAC applications. This option could be considered for future studies.
 - VHTR concepts could be developed to operate in this temperature range and provide heat to the calciner. VHTRs under development in the U.S. are currently targeting lower temperatures (X-energy at 565 °C, HolosGen at 850 °C, etc.) because of the technological challenges of operating at such a high temperatures. The ideal way to use a VHTR as a source of heat for the calcination reaction would be to mix high-temperature helium (from the VHTR primary coolant) directly with limestone, to avoid heat losses from indirect heat transfer. Even assuming perfect heat transfer from direct mixing, the resulting CO₂ would be diluted with helium, whose separation would require additional energy. Consequently, this option won't be further considered in this report.
 - The use of a re-heater operated with NPP-generated electricity to increase the temperature of the NPP-generated heat could be considered in the future.
 - For the purposes of this report, the conventional option of supplying heat to the calciner by in situ fossil fuel oxy-combustion is chosen. Since natural gas is combusted in pure oxygen, the products are only CO₂ and water vapor. Moreover, since the combustion happens within the calciner, the CO₂ from natural gas combustion and the CO₂ from calcination of CaCO₃ are mixed together. Downstream from the calciner, water vapor in the product gas is condensed and the pure CO₂ stream is further purified and compressed for pipeline transport. As a result, the calcination step inherently involves capture of CO₂ from natural gas combustion as well. Oxy-combustion of natural gas (described in Section 4.1, and shown in Figure 2-1) is used as the reference option.

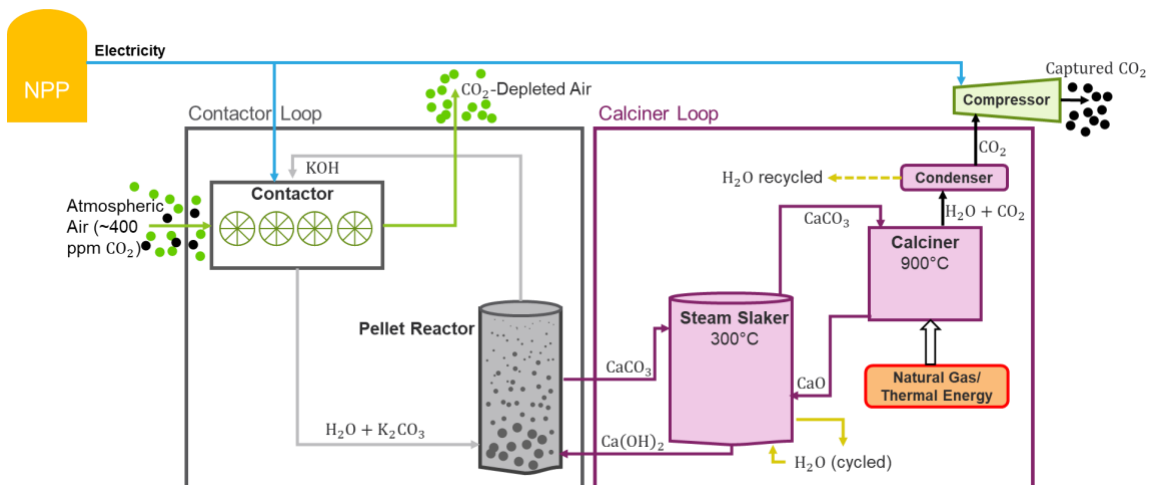


Figure 2-1. Coupled NPP&L-DAC system schematic.

2.1.2 Solid Sorbent DAC

2.1.2.1 Short Description

Solid sorbent-based DAC (S-DAC) typically utilizes a two-stage carbon capture process, as shown in Figure 2-2. During the absorption phase, large fans drive air through the CO₂ collectors. CO₂ reacts with the sorbent (amine-based, metal organic framework, zeolites, alkali metal-based, etc.) and binds to the material. The desorption phase begins as the sorbent is saturated. Temperature or pressure swing can be used to desorb the carbon dioxide from the sorbent. Heat can be supplied either directly or indirectly to the sorbent using steam or a heating medium. Any water, either adsorbed by the sorbent from the air or introduced through direct steam regeneration is separated from CO₂ by cooling the gas stream through a condenser. The S-DAC system modeled in this study uses temperature swing for sorbent regeneration with indirect heat transfer to the sorbent [14].

2.1.2.2 Potential for Coupling with NPP Technologies

The NPP can couple with S-DAC by providing heat and electricity to support its operation in several ways, as shown in Figure 2-2 (the blue lines represent the flow of electricity, and the solid black lines represent the flow of captured CO₂):

- NPP can provide electricity to run the DAC air fans, CO₂ compressors and other components of the DAC system.
- NPP can provide heat required for the desorption step. Sorbent regeneration typically requires heat at conditions close to ~150 °C and 0.5 MPa. As discussed in Section 3, there are several ways to get direct access to such steam conditions using different reactor technologies. This is a higher temperature than that of typical waste heat in Rankine Cycles (used in most PWR or SFR concepts), but it can be obtained through extraction of other steam lines at the expense of electrical output. Some VHTRs, such as the one considered in Section 3.1, provide access to waste heat at 125 °C, which is directly usable for the S-DAC process without affecting electrical production. In the analysis performed in Section 4.2, the heat exchanger (HX) is placed between NPP-produced steam/helium and steam going through Solid Sorbent, which helps avoid radioactive contamination of solid sorbent materials.

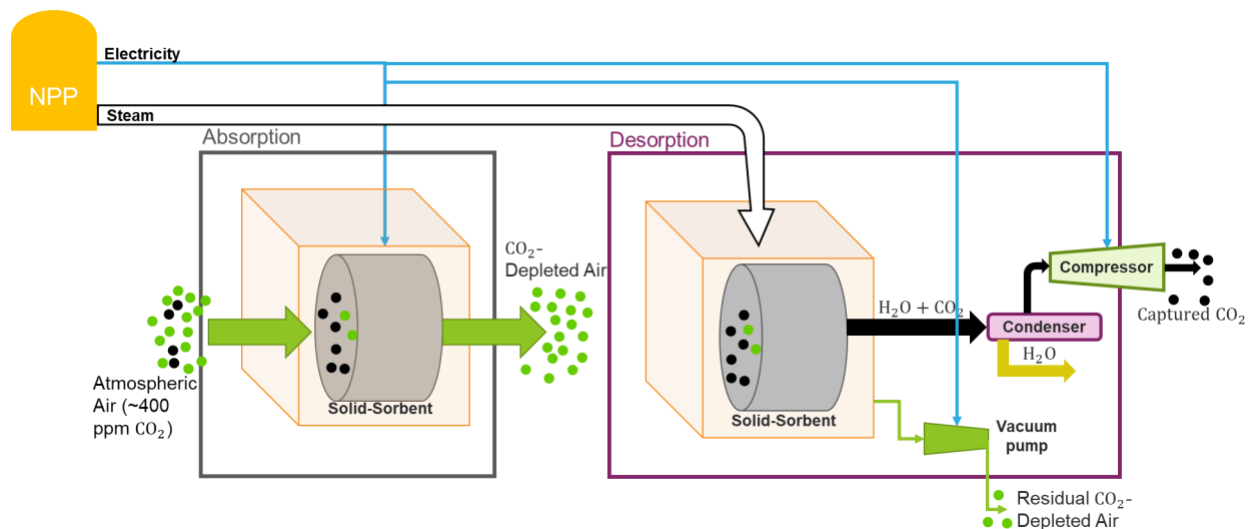


Figure 2-2. Coupled NPP&S-DAC system schematic.

2.1.3 Deployment Status and Outlook for DAC

The first large-scale commercial L-DAC plant, designed to capture 500,000 tCO₂/year, is in advanced development by 1PointFive and is expected to be operating in Texas by 2025, using Carbon Engineering, Ltd., technology [19]. This facility is designed to implement geological sequestration to store the captured CO₂. The company expects sale of the carbon credits, along with tax incentives from the U.S. IRA of 2022, to sustain its business. A 2021 DOE grant is funding Global Thermostat's work to develop the design for an S-DAC plant in Colorado with an annual capacity of 100,000 tons [20]. Internationally, an improved investment environment led to announcements of several new DAC projects in 2021, including the Storegga Dreamcatcher Project (L-DAC, United Kingdom) for CO₂ removal, and the HIF Haru Oni eFuels Pilot Plant (S-DAC, Chile) for producing synthetic fuels from electrolysis-based hydrogen and air-captured CO₂. Synthetic fuels (up to 3 million liters) are also set to be produced by the Norsk e-Fuel AS consortium in Norway by 2024, including (but not using exclusively) CO₂ captured from S-DAC. In June 2022, 1PointFive and Carbon Engineering (L-DAC) announced plans to deploy 70 large-scale DAC facilities by 2035 (each with a capture capacity of up to 1 million tonnes per year) under current policy and voluntary and compliance market conditions, while Climeworks (S-DAC) has announced the construction of its largest plant to date, Mammoth (capture capacity up to 36,000 tCO₂/year), which should become operational by 2024. One of the potential limitations on L-DAC deployment is the large water requirement (5–13 tons of water per ton of CO₂), which makes it difficult to deploy in some locations.

A considerable amount of research is being carried out in the areas of sorbent development, contactor design, siting, and alternative heat and power sources, in order to reduce the overall cost of the systems, which is a major roadblock to large-scale deployment[21] [22] [23]. While a commonly touted advantage of DAC is that it is not site specific, to reduce costs, DAC systems need to be collocated with water sources (L-DAC), CO₂ pipelines, CO₂ storage sites, and low-CO₂-footprint energy sources. Availability of low-cost or waste heat is also an advantage for many sorbent systems. For solvent systems utilizing in situ NG oxy-combustion in the calciner, proximity to NG pipelines is also advantageous. The local climate also impacts DAC system performance, with ambient temperature and humidity (for S-DAC) playing a large role. Generally, higher temperatures lead to poor sorbent performance, while the effect of humidity is positive in some sorbents and negative in others.

While S-DAC and L-DAC have been the more mature among the DAC technologies, there is a small but growing DAC portfolio of technologies that are currently below a TRL of 6, including electro-swing absorption (ESA) and membrane-based DAC (m-DAC). ESA works on the battery/electrolysis principle: an electrode absorbs CO₂ when negatively charged, and releases the captured CO₂ when a positive charge is applied [24]. In the m-DAC process, CO₂ is captured from air that is passed through gas separation membranes. However, this technology is still in its infancy, and developing compressors to compress large amounts of ambient air is unsolved [25]. ESA and m-DAC have potential for future use with nuclear power, but these low TRL DAC technologies are not considered further in the present study.

2.2 Biomass-based NET Processes

Biomass is matter derived from organisms, and the predominant form of biomass used for energy comes from terrestrial plants, which comprise about 80% of all biomass [26]. In the U.S. in 2021, over 90% of primary energy from biomass came from terrestrial plants [27, 28]. Other forms of biomass that can be used for energy will not be covered here, including aquatic plants, other photosynthetic organisms like algae, and animal wastes [26].

The biomass of terrestrial plants is called lignocellulosic biomass, and it is composed of three primary organic polymers: cellulose, hemicellulose, and lignin. The proportions of these components vary by plant source, but combined they account for about 90% of the dry plant mass, and they are composed of carbon, hydrogen, and oxygen [29]. The remaining fraction of the plant mass is composed of lipids, proteins, and

minerals, some of which also contain carbon. Ultimately, woody plants like trees are composed of approximately 50% carbon by dry weight [30].

Plants capture and sequester carbon dioxide from the atmosphere in their tissues through photosynthesis. When plants die, their carbon-bearing molecules are broken down by natural processes and returned to the atmosphere or sequestered in other organisms. Likewise, if lignocellulosic biomass is burned to produce energy, much of its carbon is released as carbon dioxide, but this is eventually taken up by other plants and sequestered in their tissues. Thus, biomass burned in the traditional way with unabated carbon dioxide emissions is carbon neutral³.

The key to using biomass for negative carbon emissions is to interrupt the flow of carbon back to the biosphere when biomass is burned or otherwise processed. This can be accomplished by removing solid, liquid, or gaseous carbon-bearing materials when biomass is heated in thermochemical processes. In all cases, the biomass must be dried first (typically with 100–150 °C heat). Next, the process choice diverges by the available heat temperature and the desired products. Combustion is exothermic (no external heat source needed), and it produces mostly carbon dioxide and water. Pyrolysis heats biomass in an anoxic environment at 200–600 °C, and it produces larger amounts of solid char with a slow heating rate. Combustion is exothermic (no external heat source needed), and it produces mostly carbon dioxide and water. Gasification heats biomass in a hypoxic environment (less oxygen than needed for complete combustion) starting above 500 °C, and it produces mostly carbon monoxide and hydrogen.

The carbon sequestration method used depends on the physical form of the carbon-bearing products. Solid char is nearly entirely carbon, and it can be used in agriculture⁴ or potentially buried. Liquid products like bio-oil, if not used as feedstocks for carbon-neutral fuels, could be reinjected into depleted petroleum reservoirs. Similarly, gaseous products could be injected into reservoirs, but they might also be disposed of in deep saline aquifers or the deep ocean where they would remain as supercritical fluids owing to high pressure. Some carbon-bearing products, like bio-oil, methane, and carbon monoxide, are potential feedstocks for other industrial processes, but using them in this way would reduce the carbon removal performance of a NET, as further discussed in Section A-2.

These processes—combustion, pyrolysis, and gasification—are described in more detail in the following sections, together with their potential to utilize the heat and/or electricity produced by an NPP. All three of these processes have been developed into commercial technologies at various scales and in multiple industries. For widespread deployment of biomass-based NETs, new biomass supply chains would have to be developed and scaled up by several orders of magnitude. For example, in Feb. 2023, the U.S. had an annual production capacity for densified biomass fuel pellets of about 12 Mt/year. Assuming that 50% of this mass was carbon and that it could be fully sequestered, that would be the equivalent of 6 Mt/year of carbon or 22 Mt CO₂/year, which is far below the 400–5,200 Mt CO₂/year needed to limit warming to 2 °C [1]. There are also concerns that larger-scale biomass production might compete for land with food production and biodiversity conservation.

Although this report focuses on carbon flows and negative carbon emissions, the thermochemical processes described here also apply to biomass upgrading for biofuel production. There are chemical and economic tradeoffs between producing biofuels and sequestering carbon for negative emissions, as discussed in Section A-2, but process optimization is beyond the scope of this work.

³ This is carbon neutral in the accounting of carbon that is embodied in the biomass. It does not cover life-cycle or supply-chain carbon emissions (e.g., energy used for harvesting and processing), the timing of release versus reuptake, or ecosystem changes.

⁴ Biochar has been studied as a soil fertility enhancer, and it is expected to remain biologically inactive for hundreds to thousands of years.

2.2.1 Biomass Combustion (BECCS)

2.2.1.1 Short Description

Like coal, biomass can be burned (combusted) in a boiler to produce heat for industrial processes or to produce steam for electricity production. Since the flue gas is rich in carbon dioxide, it can be processed with a carbon dioxide capture technology, thus removing most of the original carbon from the waste stream. This captured carbon dioxide can then be transported and sequestered. Whereas this process with coal would still produce net positive carbon emissions, the same process fueled with biomass would produce net negative carbon emissions. This set of post-combustion capture technologies is often referred to as bioenergy with carbon capture and storage (BECCS).

For biomass combustion, typical feedstocks include wood and wood wastes, but other types of lignocellulosic biomass are used in some cases. Most often, biomass is reacted with air at high temperature in a boiler. Since combustion is an exothermic process, no external heat is required. Flue gases consist of carbon dioxide, water vapor, nitrogen oxides, and sulfur dioxide. The carbon dioxide can be separated from the flue gas stream via the same capture technologies being considered for DAC: solvents, sorbents, and membranes. This post-combustion capture process can capture 95% of the carbon dioxide in the flue gas [31].

One significant difficulty with DAC and post-(air)-combustion capture is that air is nearly 80% nitrogen, necessitating much larger and more expensive components to handle the extraneous nitrogen. Other combustion-based technologies circumvent the nitrogen problem by reacting the fuel with oxygen only or an oxygen-bearing compound, which is known as oxy-fuel combustion. Examples include the Allam–Fetvedt cycle (commercialized by NET Power) and chemical looping combustion. Those CO₂ separation processes are capital-intensive and require energy (heat and electricity), which could come from the biomass combustion, the grid, or an NPP. Their carbon dioxide capture efficacy is also typically 85%, which is lower than post-combustion capture [31].

2.2.1.2 Deployment Status and Outlook

According to the IPCC, BECCS is at TRL 5–6 with worldwide mitigation potential of 0.5–11 Gt CO₂/yr [6]. However, the International Energy Agency (IEA) classifies biopower with post-combustion capture to be at TRL 8 [32], owing partly to its commercial demonstration at two power plants in Japan and the U.K. The Mikawa BECCS power plant in Japan began commercial operations in 2020; it is a former coal plant retrofitted to burn biomass with post-combustion capture [32]. In 2019, the Drax power plant in the U.K. started capturing 1 tonne CO₂/day at one of its four 660-MWe biomass units [33].

2.2.1.3 Potential for Coupling with NPP Technologies

A process schematic for a typical biopower system with post-combustion carbon capture (BECCS) is shown in Figure 2-3. Because biomass combustion is exothermic and self-sustaining, there is no need for external energy from a nuclear reactor. The drying of biomass feedstocks and the regeneration steps of the carbon capture processes could be accomplished by diverting some of the combustion heat. The auxiliary electrical load requirements from the carbon capture equipment could be met with power produced at the turbogenerator. Alternatively, a nuclear reactor could be operated to provide the heat and electricity to operate the carbon capture equipment, which will increase the electricity production of the biomass plant, but only at the expense of that of the NPP (the impact of DAC on NPP operation is discussed in Section 4). Consequently, there is no obvious way that external heat or electricity from a nuclear reactor could improve this process.

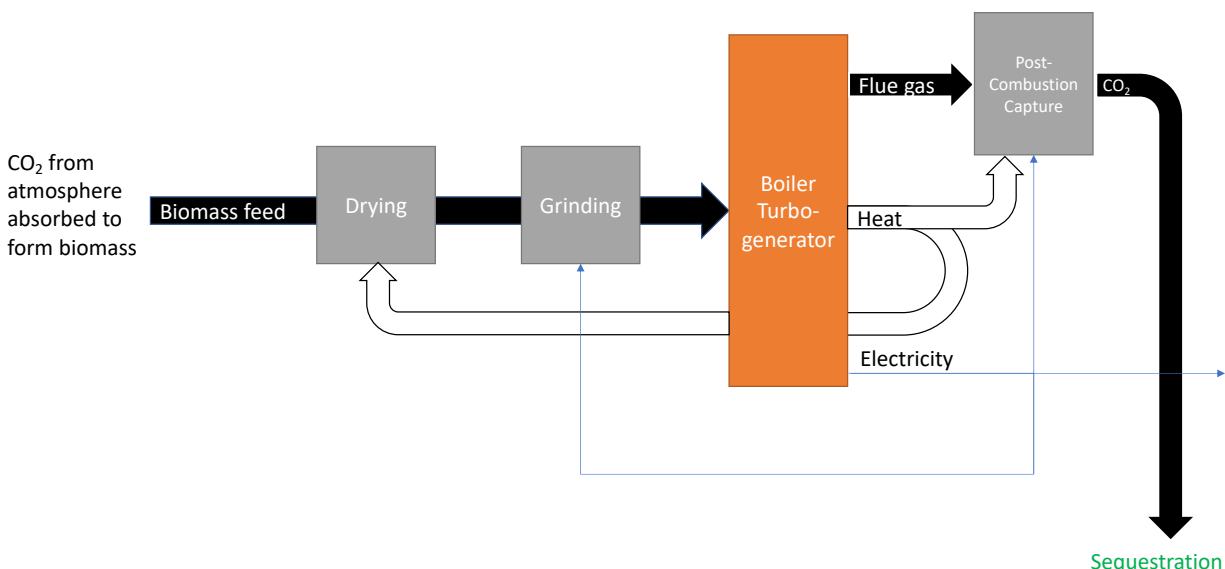


Figure 2-3. BECCS system schematic. Note that there is no NPP coupling.

2.2.2 Biomass Pyrolysis (PyCCS)

2.2.2.1 Short Description

Pyrolysis of biomass is the process of thermo-chemically⁵ decomposing organic material at high temperatures (200–600 °C) in the absence of oxygen (i.e., without CO₂ emission). There are various ways of providing the heat required to enable pyrolysis (microwave, external combustion, etc.), and nuclear heat and/or electricity could be considered in this process. Other related terms include torrefaction (usually slow heating below 300 °C) and hydrothermal liquefaction (pyrolysis in steam or another solvent). “PyCCS” is the term used for Pyrogenic application to Carbon Capture and Storage [34].

There are three types of products from biomass pyrolysis, with varying production yields that are optimized by manipulating the biomass type, temperature, chemical kinetics, and other parameters:

- Biochar is a solid residue rich in carbon;
- Bio-oil is composed of liquid components that contain hydrocarbons and water;
- Bio-gas or syngas is a mixture of gases, including carbon monoxide (CO) and hydrogen (see Section 2.2.3 for more on gasification).

Biochar can be mixed with soil to store carbon while returning mineral nutrients to the soil following pyrolysis, leading to a potentially (but not always) significant increase in the yield of some crops (by 100% in the Nepal region) [34]. Carbon storage in biochar is a recognized way to store CO₂ with a long storage time frame estimated at 500 years or more. Biochar can also be used in some industrial applications such as supercapacitor materials (which are used in transportation batteries).

⁵ There exist also chemical and biochemical pathways to convert biomass into biofuels, but these are not discussed in this report because nuclear energy has no clear role in these pathways.

Both bio-oil and bio-gas can be used to fuel the pyrolysis process or to produce valuable fuels such as hydrogen from steam reforming.⁶ Several commercial applications of bio-fuels have been considered, such as bioplastics and amendment of asphalt and building materials. Use and production of bio-oil from nuclear energy and biomass was described in [12] and is further discussed in Section A-2. Bio-fuels (or at least the less economically valuable components) could also be sequestered relatively easily, instead of being commercialized for combustion, to increase the negative emission performance of PyCCS [34], as proposed by Charm Industrials [35]. Bio-gas that contains 15 to 45% of the biomass carbon could be sequestered through more expensive traditional sequestration systems.

2.2.2.2 Deployment Status and Outlook

According to the IPCC [6], pyrolysis is at TRL 6–7 with worldwide mitigation potential of 0.3–6.6 Gton CO₂/yr. Pyrolysis is a well-known and well-developed concept, first used in ancient Egypt. It is typically applied to produce coke from coal, which is an essential part of the steel production process. Pyrolysis-generated biofuels were used to produce alternative transportation fuels during World Wars I and II. Pyrolysis was also widely used in the chemical industry up until 1950 to produce basic chemicals such as methanol, until it became much cheaper to produce them from fossil oils [36].

A significant amount of research is ongoing to optimize pyrolysis processes for different biomass forms and targeting different products. Slow pyrolysis at low temperatures can produce more biochar, while flash pyrolysis (reaching 400–600 °C within a fraction of a second) produces bio-oil, and fast pyrolysis produces bio-oil and bio-gas. For CO₂ sequestration purposes, slow pyrolysis with temperatures in the 500–650 °C range is recommended, with a realistic sequestration of 70–80% of CO₂ when sequestering biochar and bio-oil, but theoretically, this level could reach 90% [34]. Changing conditions will likely be required if economical products (coming from bio-oil, biochar or bio-gas) are expected, as higher temperatures lead to increased bio-oil and bio-gas yield with improved composition (H₂ and CH₄ production yields).

According to [34], the PyCCS technology is ready for implementation across scales ranging from small to industrial. Networks of smaller-scale PyCCS systems would reduce environmental side effects but would come with larger logistic challenges.

Environmental impact from large-scale biochar use is still an area of active research and caution as it can positively or negatively affect soil properties [34]. Current areas of research focus on cost reduction, improving process reliability, and scaling up. Currently, biochar is produced for 300–600 euros/ton, and bio-oils for 150–400 euros/ton, which is higher than their energetic value. It will take CO₂ carbon penalties and storage incentives to make this process economically attractive [34].

2.2.2.3 Potential for Coupling with NPP Technologies

Figure 2-4 shows a schematic of an example pyrolysis process coupled with an NPP. Pyrolysis begins with a low-temperature endothermic (energy-consuming) process, which is followed by an exothermic process at high temperature (achieved through the use of bio-gas) [37]. It is not clear if the overall pyrolysis process with the use of bio-gas is always exothermic or could still be endothermic in some cases. Without the use of bio-gas, it appears to be always endothermic. Consequently, providing energy to the system via an NPP would enable improved bio-gas yield.

A NPP (SFR or VHTR) can play a role in providing high-temperature heat and electricity for slow-process low-temperature (500–650 °C) pyrolysis. For low-temperature heat application, an HX could be placed on the NPP secondary loop to extract the heat required to fuel pyrolysis with circulating N₂ or another inert gas. High-temperature flash pyrolysis processes could potentially use nuclear electricity to

⁶ Steam reforming is a process for converting hydrocarbons into hydrogen and CO through treatment with high-temperature steam, in the presence of a catalyst [103].

reach the targeted temperature. Electricity from the NPP may also be used at various stages of the PyCCS process.

This process may be better suited for small-scale applications, involving either small-size reactors or nuclear reactors dedicating only very small fractions of their high-temperature heat to this process. Alternatively, this process may be connected to other back-end processes for processing pyrolysis products, such as a bio-fuel refinery or biochar vaporization, which are also energy-intensive processes used to increase the value of these products as further discussed in Sections 2.2.3 and A-2.

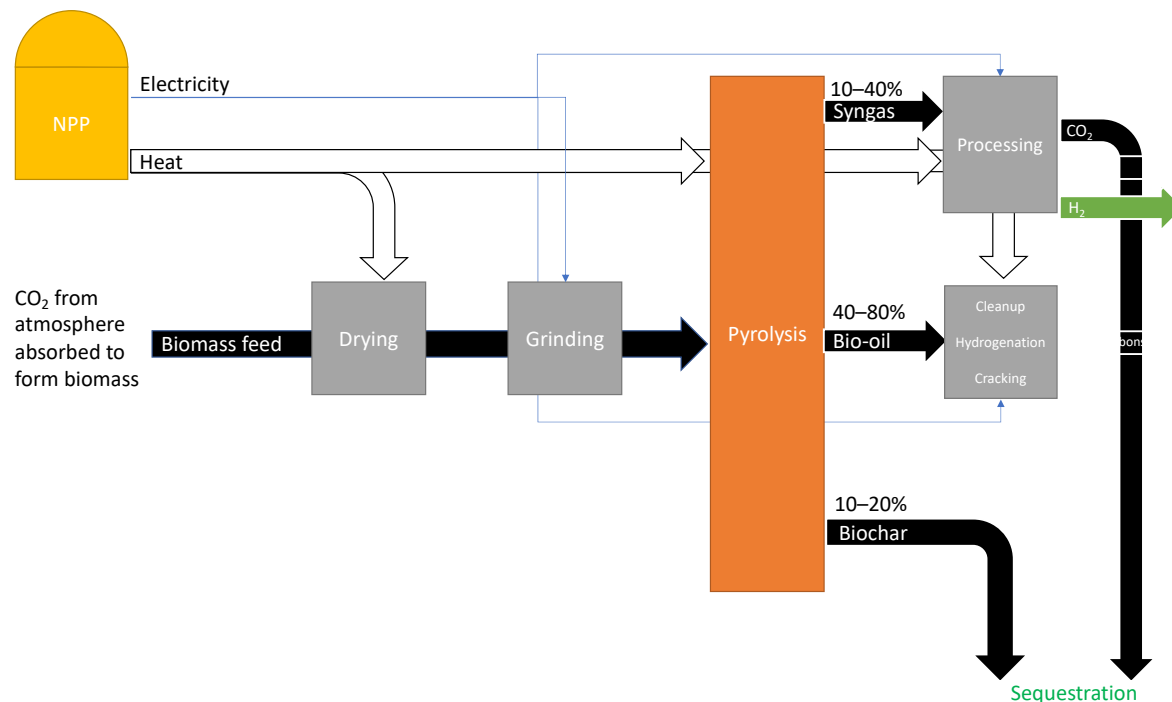


Figure 2-4. Coupled NPP&PyCCS system schematic.

2.2.3 Biomass Gasification

2.2.3.1 Short Description

Gasification is the conversion of biomass or hydrocarbons into various product gases. Focusing on biomass, the feedstocks for gasification can be raw biomass, dried biomass, or char (produced from the above-described pyrolysis process). These products are fed into a chemical reactor called a gasifier. If the available oxygen is kept significantly below the stoichiometric mixture for combustion (or is unavailable in some cases), the biomass will be gasified, producing hydrogen, carbon monoxide, carbon dioxide, steam, methane, and other minor gases. This gasification occurs because the primary combustion products (carbon dioxide and steam) are reduced by the solid char (carbon), stripping them of oxygen. Smaller amounts of tar and char are also produced. Carbon monoxide can further be reacted with steam in the water-gas shift reaction to produce carbon dioxide and hydrogen.

The reduction reactions at the heart of the gasification process (steam and carbon dioxide reacting with char) require temperatures of 500–1,400 °C [38], depending on the gasifier design. On the lowest end of gasification temperatures, up to 70% by volume of the product gases will be hydrogen [39]. Increasing the gasifier temperature tends to create more carbon monoxide and carbon dioxide, decreasing hydrogen, methane, tar, and char production [40]. This would be advantageous where gaseous carbon-bearing products are desired for sequestration rather than liquid or solid products.

Compared to combustion, gasification concentrates ash and other contaminants which could otherwise be released to the environment in the combustion flue gases. Compared to both pyrolysis and combustion, gasification can generate large amounts of hydrogen, which could be sold for various purposes.

2.2.3.2 Deployment Status and Outlook

Gasifiers have been designed and built since the early 19th century, with early examples used to produce combustible town gas (carbon monoxide and hydrogen) before the exploitation of natural gas. There are several large industrial gasifier producers worldwide, with most designs being either fixed/moving bed or entrained flow [41]. Advanced gasification technologies, such as plasma torch, are in various stages of development, demonstration, and deployment [42].

Carbon-bearing products from biomass gasification should be carefully accounted for to avoid reducing the efficacy of the negative emissions aspect of the technology. Carbon monoxide and hydrogen are the feedstocks for the Fischer-Tropsch process, which produces liquid hydrocarbons. These reactions do not occur during gasification because the temperature is too high. Besides the potential to produce liquid hydrocarbons, carbon monoxide can be combusted as a fuel or used in many industrial processes such as acetic acid production. However, any carbon monoxide produced by biomass gasification that is not subsequently sequestered would potentially lead to some carbon being recycled in the biosphere.

2.2.3.3 Potential for Coupling with NPP Technologies

While oxygen-rich combustion is exothermic and can be a self-sustaining reaction, oxygen-poor gasification (reduction) is endothermic, so it needs an external heat source (as in pyrolysis processes). A gasification plant can be designed to use its own combustible product gases (carbon monoxide, hydrogen) to produce external heat for the gasifier, but this could require up to 15% of the original feedstock for combustion [38]. Nuclear reactor heat could be supplied here instead, leaving carbon monoxide to be further oxidized to carbon dioxide for capture and ultimate sequestration, and the hydrogen could be sold. This would boost the conversion efficiency of input biomass to output carbon for sequestration. An example coupled NPP-gasifier system schematic is shown in Figure 2-5.

Newer gasifier designs that use plasma torches could also be compatible with nuclear reactors. Here, nuclear-supplied heat could pre-heat the incoming biomass, and then electricity would be used to power the plasma torches.

VHTRs (and possibly SFRs) could provide the required temperatures for direct gasification. Fluidized bed gasifiers would be most compatible with nuclear-supplied external heat, since updraft and downdraft gasifiers utilize partial biomass combustion to supply heat for the reduction reactions [43]. The fluidizer is typically air, oxygen, steam, carbon dioxide, or mixtures of two of these. It is likely that an HX would be used to transfer heat from the primary or secondary loop of the NPP to the fluidizing gas in contact with the biomass.

Additionally, nuclear heat and/or electricity would be used in separating syngas into its component gases (H_2 , CO, CO_2 , CH_4 , etc.). Carbon monoxide could be combusted for energy, or it could be further reacted with steam in the water-gas shift reaction to produce carbon dioxide and hydrogen, leading to another carbon dioxide stream for sequestration. Likewise, the methane stream could be combusted, or it could be reacted with steam (reformation reactions) to form carbon monoxide or carbon dioxide, which again can be further processed for ultimate sequestration.

Gasifiers have been designed to ramp their production up and down, and this is primarily in the context of integrated gasification-combined cycle power plants [44]. However, very fast ramping is not recommended to avoid material stress. The economic impact of variable production has not been assessed, but it could be considered for future analysis.

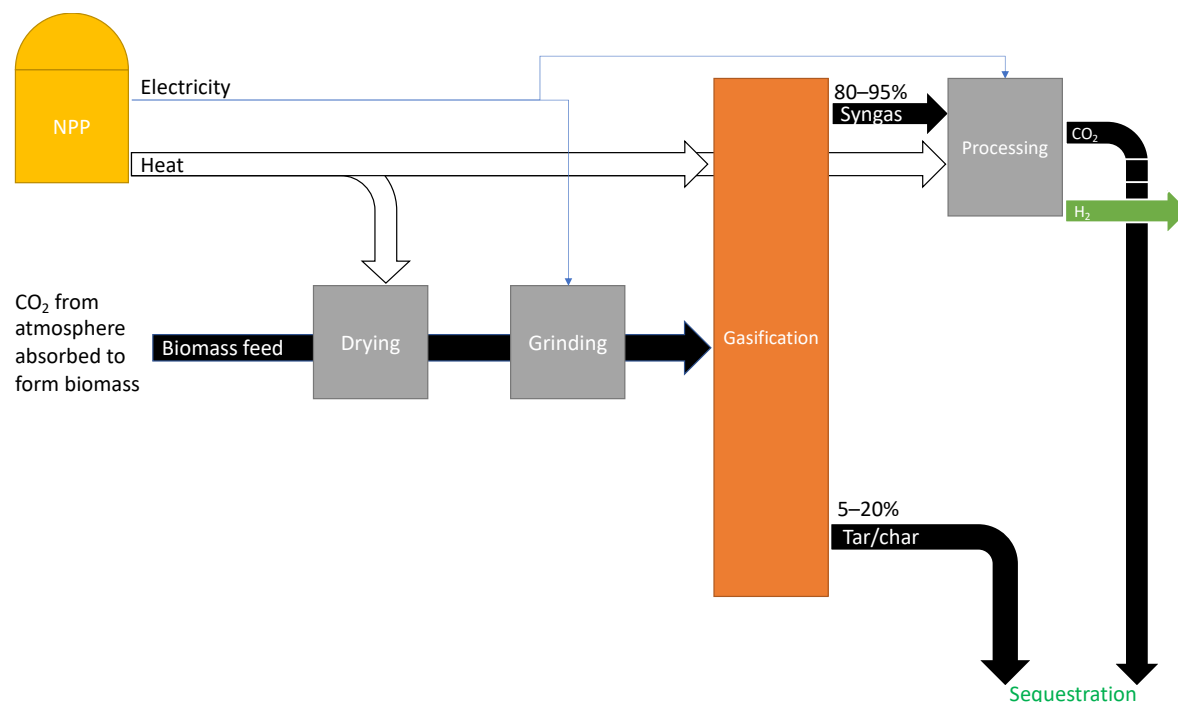
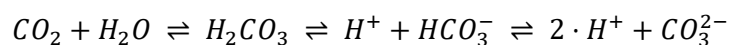


Figure 2-5. Coupled NPP&Gasification system schematic.

2.3 Water-Based NETs

Atmospheric carbon dioxide can also be removed via chemical reactions with water. When fossil fuels are burned with air, some of the fossil carbon released into the atmosphere as carbon dioxide dissolves into surface waters, reacting with water molecules to form carbonic acid (H_2CO_3). The aqueous carbonic acid can further dissociate into bicarbonate (HCO_3^-) and carbonate (CO_3^{2-}) anions in varying proportions, depending on the pH (Eq. 3; Figure 2-6). Freshwater pH is typically in the range of 6.5–8.5, so the combined carbon dioxide and carbonic acid concentration can vary from nearly half at the lower end to almost zero at the higher end.



3

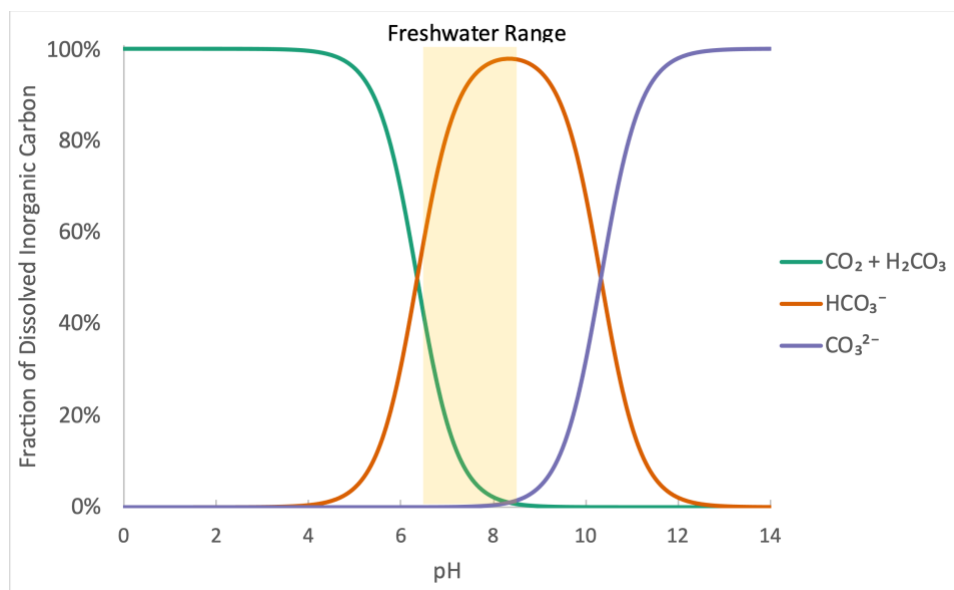


Figure 2-6. Variation of equilibrium concentration with pH for various carbon-bearing species in water.

At a typical seawater pH around 8.1, carbonic acid rapidly dissociates into bicarbonate and carbonate anions. The resulting seawater is richest in bicarbonate anions (97.7%), followed by dissolved carbon dioxide gas (1.7%) and carbonate anions (0.6%). Thus, the chemical reactions in seawater pH favor the formation of bicarbonate, which tends to stay in solution.

Water's pH can be manipulated in a variety of ways, and Figure 2-6 suggests that making water more alkaline would allow for the dissolution of more carbon dioxide from air, while making water more acidic would allow more dissolved carbon dioxide to come out of solution, facilitating capture. Both of these directions for pH manipulation have been employed in NETs and will be described in the following sections: water alkalization in EEW (2.3.1) and water acidification in indirect seawater capture (2.3.2). These techniques are also being used together in the new Equatic process [45]. The coupling of these NETs with nuclear power is prospective at this time, but it is worth considering since all of these techniques require low-carbon energy inputs.

2.3.1 Engineered Enhanced Weathering

2.3.1.1 Short Description

Enhanced silicate rock weathering (EW) techniques aim at accelerating the naturally occurring chemical reactions between rocks (like basalt, which is abundantly stockpiled as a by-product of the aggregate industry, and has fast-weathering properties), water, and atmospheric CO₂ with the aim to store carbon in minerals (carbonates or silicates) [46]. Traditionally, this storage is accomplished by spreading crushed rocks near water sources: “Currently, the weathering of rock by carbon dioxide and water, a natural process, absorbs about 1.1 Gt CO₂ per year from the atmosphere, mainly stored as bicarbonate in the ocean.” [43] One significant advantage of EW over the DAC approaches is that EW does not require CO₂ compression and underground storage, as CO₂ is directly stored in the calcium carbonate of the soil or in seawater in the form of bicarbonate ions as described in equation 4 [46]:



The use of EW for carbon capture has the following limitations:

- Chemistry occurring naturally can potentially reverse the reaction and release some of the CO₂ to the atmosphere (likely with a long kinetics);
- It requires handling of a large amount of crushed rock and water; and
- It is a slow naturally occurring process.

Research is actively being proposed to evaluate whether the process could be sped up through the use of flowing water and combination with DAC for increased CO₂ concentration. Several concepts of “engineered” EW (referred to below as EEW) are actively being developed [47, 48], and there is significant design optimization underway that is expected to improve performance. This summary focuses on one approach that may couple particularly well with a nuclear reactor. This is a specially designed packed bubble column (PBC), proposed in [48], in which the reacting mineral particles are contacted with air and water and provide interfacial area for gas-liquid mass transfer.

The PBC-based EEW technology uses a two-step approach, as described in Figure 2-7:

- To begin the process, atmospheric air would have to be enriched in CO₂, possibly using a DAC system. This enrichment is required for use of seawater instead of fresh water in the PBC.
- The CO₂-enriched air is then fed into the PBC via a bubbler. Here the CO₂ would rise through the PBC and bind itself to the minerals.

2.3.1.2 Deployment Status and Outlook

According to IPCC [6], EW is at TRL 3-4 with “realistic” worldwide mitigation potential of 2-4 GtonCO₂/yr, but some studies have shown up to 95 GtonCO₂/yr. The EW is a naturally occurring process, and accelerated technologies of EW are under active development. The PBC-based EEW technology described in [47, 48] is very recent and is demonstrated at laboratory stage, but significant work is likely needed to optimize performance for industrial scale. Coupling of PBC-based EEW with NPP is at a very prospective stage and has never been considered outside of this report, to our knowledge.

This process requires a lot of water, but it can be made compatible with seawater (with the added use of DAC), so location in coastal areas may be more appropriate. The process requires access to a large amount of Silicate rock, so it requires transportation access. The quantity of water and rock required are discussed in Section A-1.

Long-term retaining of carbon into the seawater must be properly accounted for, in order not to over-estimate potential of EEW as a NET. The degassing of CO₂ is the loss of captured CO₂ from water that is returned to the atmosphere. In addition to degassing, the naturally-induced precipitation of carbonate in seawater may lead to additional CO₂ release, which would further reduce performance of the EEW process.

2.3.1.3 Potential for PBC-based EEW Coupling with NPP Technologies

Nuclear can support the PBC-based EEW technology by providing both heat and electricity, as detailed in Figure 2-7:

- NPP electricity is used for pumping water and air into the PBC system, for crushing rocks, etc. Any NPP technology would be suitable.
- NPP heat and electricity are used for DAC operation to increase the CO₂ concentration in the air going through the PBC. The method can be similar to that discussed in Section 2.1. However, the cost of using DAC will be reduced since there is no need to enrich CO₂ to very high concentrations (~5%) in this PBC system.

Consequently, any NPP type can theoretically be compatible with EEW technologies. The best performance will be obtained from the NPPs that pair well with DAC technologies (as discussed in Section 2.1).

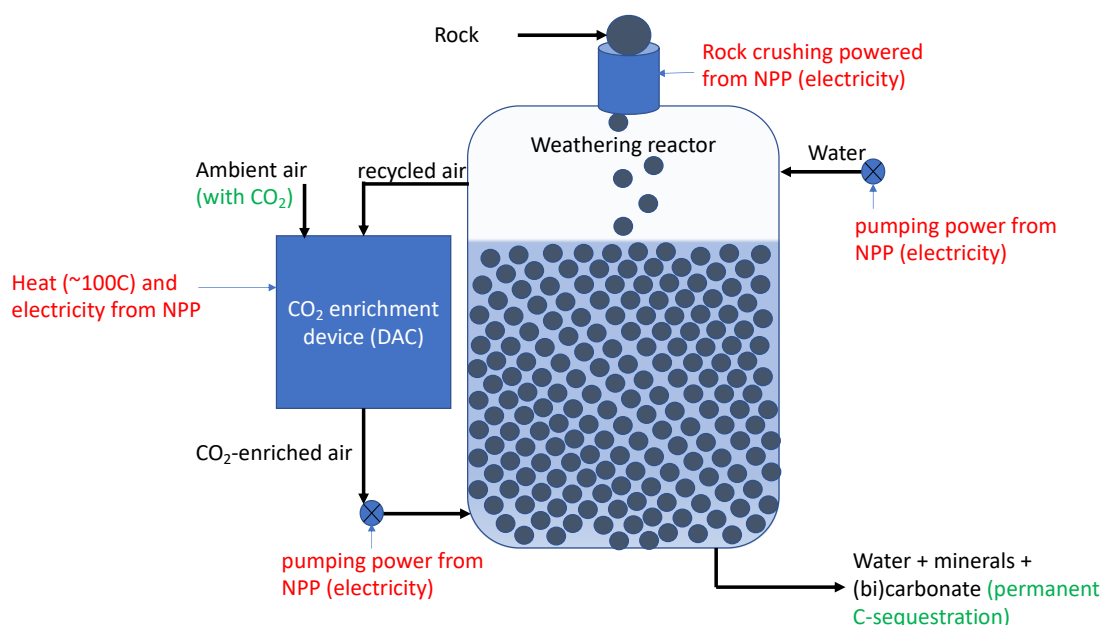


Figure 2-7. Coupled NPP&EEW system layout.

2.3.2 Indirect Seawater Capture (AKA Direct Ocean Capture)

If dissolved inorganic carbon⁷ (DIC) is removed from seawater, it shifts the reaction in Eq. 3 out of equilibrium, favoring the forward reaction of dissolved CO_2 reacting with water to quickly form bicarbonate ions. This shift allows more atmospheric CO_2 to be dissolved, reducing atmospheric CO_2 indirectly, thus the moniker “indirect seawater capture” (ISC).

While the annual mean carbon dioxide concentration in the atmosphere is approximately 420 ppm mole fraction [49], it is around 500 ppm mole fraction (as dissolved CO_2) in the Pacific Ocean [50], and total seawater DIC is approximately 100 times higher than this. More importantly for engineering design, the volumetric density of atmospheric carbon dioxide is approximately 0.82 mg/l compared to about 29 mg/l DIC in seawater, about 35× higher. Thus, the much higher volumetric density of inorganic carbon found in seawater compared to the atmosphere could mean lower costs per tonne of carbon captured.

ISC of carbon has been reported using several methods, most of which involve electrochemical pH manipulation (pH swing) to temporarily reduce the pH below 6, which favors the gaseous carbon dioxide and carbonic acid sides of Eq. 3 [51], before the pH is returned close to the original level. These methods include gas-permeable membranes [52], ion exchange resins [53], membrane electrodialysis [54] [55], membrane electrolysis [56] [57], dual electrolytic cells [58], and electrochemical hydrogen looping [59]. All of these are designed to extract carbon dioxide as a gas from seawater, although some may be modified to directly produce minerals like calcium carbonate or calcium bicarbonate [60] [61]. Membrane electrolysis also generates hydrogen gas as a byproduct, which is a valuable commodity.

⁷ Dissolved inorganic carbon is the sum of all inorganic carbon compounds found in an aqueous solution. For seawater, these are almost entirely carbon dioxide, carbonic acid, carbonate, and bicarbonate.

Two membrane-based methods are discussed in further detail in the following sections: membrane electrodialysis and membrane electrolysis.

2.3.2.1 Membrane Electrodialysis

2.3.2.1.1 Short Description

Electrodialysis techniques use semipermeable membranes and electric fields to separate different types of molecules. For DIC removal from seawater, bipolar membranes are used to selectively increase the concentration of H^+ cations with an applied voltage, lowering the pH. This technique is referred to as bipolar membrane electrodialysis (BPMED). If multiple BPMED cells are connected in series, the pH of the seawater is lowered in sequence. The acidified seawater is placed under vacuum to cause the CO_2 to come out of solution, yielding a pure gas. Finally, the acidified, decarbonized seawater is mixed with the alkalized seawater on the other end of the cell stack to yield a moderate-pH effluent.

The seawater pH in the final BPMED cell will determine the relative concentration of gaseous CO_2 . For example, a pH of results in approximately 50% of DIC as CO_2 , whereas a pH of 4 results in approximately 99% of DIC as CO_2 [54]. Lower pH would yield more CO_2 per unit of input seawater, but at the cost of additional BPMED cells.

2.3.2.1.2 Deployment Status and Outlook

BPMED with seawater was demonstrated at laboratory scale as early as 1995 [62]. Several experimental studies have been conducted on CO_2 -rich solutions since 2000 [63] [64], but only a few have considered carbon removal from seawater. One study demonstrated the extraction of 59% DIC from seawater with an energy consumption of 242 kJ/mol(CO_2) [54]. The key BPMED technology is in widespread industrial use for water purification, acid/base production, and pH correction in the food industry [65].

2.3.2.1.3 Potential for Coupling with NPP Technologies

Electrodialysis requires electricity to set up the electric fields in the electrochemical cells, to pump seawater, and to run the vacuum stripper, among other functions. Increasing seawater temperature would also increase reaction rates, although the use of higher temperatures and pressures with BPMED has not been reported in the literature. NPPs of all types could supply the necessary electricity and potentially also heat below 100 °C for preheating the feedwater.

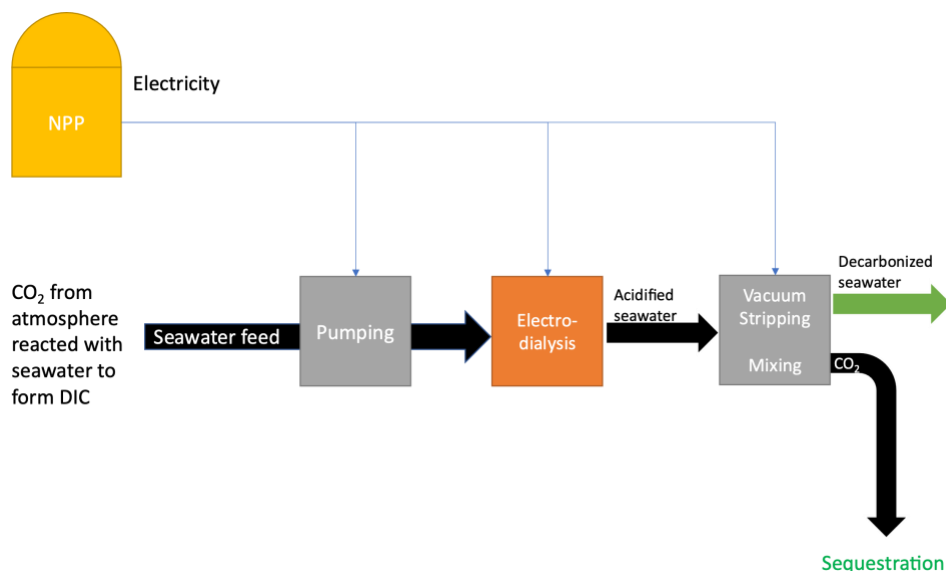


Figure 2-8. Coupled NPP&Electrodialysis system schematic.

2.3.2.2 Membrane Electrolysis

2.3.2.2.1 Short Description

Electrolysis is the use of a constant electric current to produce chemical reactions that would not spontaneously occur. In the case of water, electrolysis breaks water molecules into molecular oxygen (at the anode) and molecular hydrogen (at the cathode). The anode and cathode reactions also produce protons and electrons, and these can be exploited with bipolar cation exchange membranes to create conditions beneficial for carbon dioxide removal.

One example of membrane electrolysis uses a three-compartment electrochemical cell [56]: an anode compartment, a center acidification compartment, and a cathode compartment. Deionized water is continuously flowed separately through the anode and cathode compartments, and water electrolysis occurs here. Seawater is flowed into the center compartment. A cation exchange membrane separates the anode and center compartments, and the protons produced from electrolysis at the anode are selectively migrated towards the cathode. Next, these protons enter the center-compartment seawater, which is rich in sodium ions. Another cation exchange membrane separates the center and cathode compartments, and the sodium ions migrate through the membrane into the cathode compartment.

In this setup, the anode compartment produces molecular oxygen, while the cathode compartment produces molecular hydrogen and sodium hydroxide. The center compartment produces seawater with a pH low enough to encourage the formation of carbon dioxide gas, which can be stripped under vacuum. The decarbonized, acidified seawater can be reacted with the sodium hydroxide from the cathode compartment to bring it back to a neutral pH. Besides seawater, a continuous supply of deionized water is needed to flow through the anode and cathode compartments.

The end products are hydrogen, oxygen, and carbon dioxide gases in separate streams. Both hydrogen and oxygen gases are valuable byproducts, and the carbon dioxide can be transported or further reacted for sequestration. Most of the energy required for this membrane electrolysis process is used for water electrolysis; no additional energy is required to create the CO₂-rich center-compartment seawater. Some energy is required to run the vacuum pumps for oxygen, carbon dioxide, and hydrogen removal from the various compartments.

2.3.2.2.2 Deployment Status and Outlook

Membrane electrolysis has been demonstrated at the laboratory scale using natural seawater (83 ml/min CO₂ with current of at least 6 A). Hydrogen generation increased proportionally to the applied current [56]. A further study described process modifications to improve the electrical efficiency and to decrease the electrode polarity reversal time, which is needed to mitigate electrode fouling [57]. This technique was designed as the precursor to synthetic fuels production from seawater, so the energy required for carbon dioxide production is relatively high, although this need is partially offset by the energetic value of the byproduct hydrogen gas. All components used were commercially available, including the cation exchange membranes.

2.3.2.2.3 Potential for Coupling with NPP Technologies

Electricity is required for reverse osmosis water treatment (deionized feedwater to the anode and cathode compartments), water pumps, electrolysis, and vacuum pumps. Increasing feedwater temperature was not reported, but it is likely that this would increase reaction rates if compatible with the cation exchange membranes and other components. NPPs of any type could supply the electricity and potentially low-temperature heat for this process. A theoretical study was conducted on the possibility of producing synthetic jet fuel from seawater, and nuclear power was found to be a viable energy source [66].

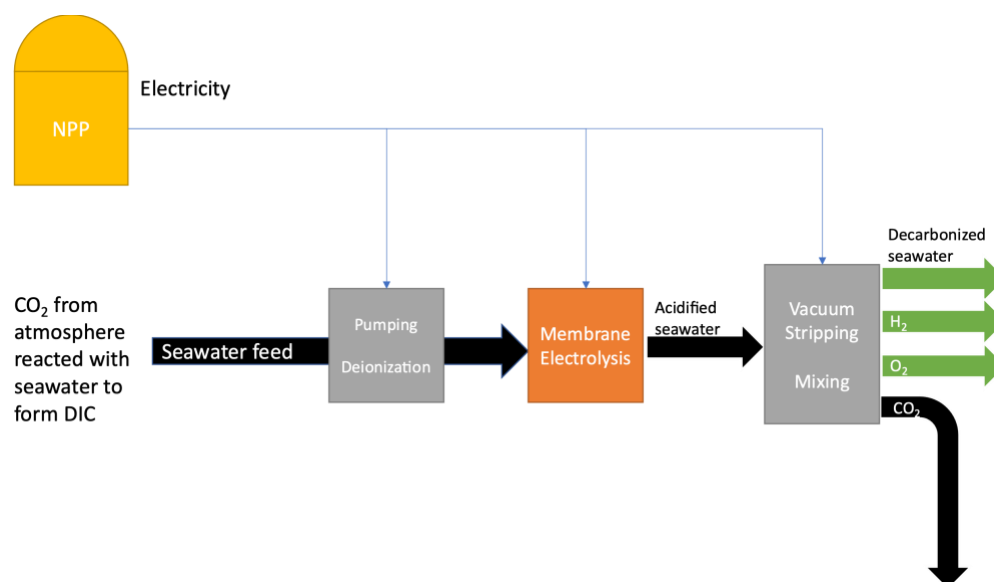


Figure 2-9. Coupled NPP&Electrolysis system schematic.

2.4 Summary of NET Compatibility with NPPs

The previous sections describe a wide range of NETs that may have potential for coupling with nuclear energy. Table 2-1 summarizes these NETs and their energy needs.

It is important to differentiate between NETs that will remove CO₂ directly from the atmosphere (DAC and EEW) and indirectly, by extracting it from the ocean (ISC) or from biomass (BECCS, PyCCS, gasification). Some NETs will produce CO₂ gas (DAC, ISC, BECCS, gasification) that will need geological sequestration for long-term storage. Others will transform CO₂ into other forms for sequestration or partial utilization: EEW as bicarbonate diluted in water, and PyCCS as biochar or bio-oil.

While the main purpose of NETs is to reduce atmospheric CO₂ concentrations, several potentially attractive byproducts may be generated from some of them, such as bio-gas or bio-oil from PyCCS, hydrogen from ISC or gasification, and electricity from BECCS.

Except for the BECCS process, the NET systems considered would benefit from decarbonized electricity generated by NPPs. Some NETs—S-DAC and potentially EEW and ISC—could also benefit from NPP waste heat (with essentially zero production cost) or some low-temperature heat. Finally, some NETs—L-DAC, PyCCS, and gasification—would benefit from high- to very-high-temperature heat from NPPs. Initial assessments of ramping capability of these systems are provided in Table 2-1, and initial assessments of economic incentives to operating NPP&DAC systems in a flexible way are provided in Section 4.3.2.4.

Finally, NPPs have the potential to pair well with DAC, EEW, and ISC systems by providing both electricity and heat. For BECCS, an NPP would not be expected to provide significant additional value to a system that produces its own decarbonized heat and electricity. For PyCCS and gasification, the NPP can provide both heat and electricity to increase the efficiency of these systems (e.g., it would save bio-gas that would otherwise be used to fuel these systems).

Following this review, a detailed techno-economic analysis of coupled NPP&DAC processes is proposed in Section 4, while a preliminary analyses with EEW and PyCCS is summarized in Appendix A. First, however, a detailed review of the quantity and quality of heat available from different types of NPPs to match the heat temperature described in Table 2-1 is required, and is completed in the next Section.

Table 2-1. Summary description of NETs and their compatibility with NPPs.

	Direct Air Capture Processes		Biomass-Based Processes			Water-Based Processes	
	L-DAC	S-DAC	BECCS	Gasification	PyCCS	EEW	ISC
Short description	Liquid solvent Direct Air Capture (high-temp.) captures CO ₂ from atmosphere	Solid sorbent Direct Air Capture (low-temp.) captures CO ₂ from atmosphere	Biomass combustion produces electricity, CCS from flue gas	Biomass gasification produces H ₂ and CO ₂ that are captured with CCS from the flue gas	Biomass pyrolysis produces biochar, bio-oil and bio-gas; carbon captured in flue gas, char	Engineered enhanced weathering: reacts atmospheric CO ₂ with rocks, stores as bicarbonate in sea	Indirect Seawater Capture systems: convert bicarbonate from seawater into CO ₂ for geological sequestration
Potential for coupling with NPP technologies	NPP to provide electricity and maybe heat	NPP to provide heat and electricity	NPP could provide heat/electricity for CCS, but these would more likely come from biomass combustion	NPP to provide heat (could come from bio-gas combustion) and electricity	NPP to provide heat (could come from bio-gas combustion) and electricity	NPP to provide electricity and heat (as in DAC)	NPP to provide electricity, maybe low-temp. heat
Heat demand	High-temp. heat (>900 °C) if available (VHTR)	Low-temp heat (~150 °C)	(Supplies own heat)	>500 °C Slow ramping	200–600 °C Slow ramping	Same as DAC	<100 °C Ramping unknown
Electricity demand	Likely baseload	Likely baseload (may be flexible)	(Supplies own electricity)	Ramping unknown	Ramping unknown	Same as DAC	Ramping unknown
Carbon-bearing products for sequestration	CO ₂	CO ₂	CO ₂	CO ₂ (and some biochar and tar)	Biochar, CO ₂ (bio-oil ¹)	HCO ₃ ⁻	CO ₂
Major byproducts	None	None	Steam, electricity	H ₂ , CO	Bio-oil	None	H ₂ , O ₂ in some designs
Minor byproducts	None	None	None	CH ₄	H ₂ , CO, CH ₄	None	None

¹ Bio-oil could be directly sequestered, but it could also be used as a feedstock for a biorefinery to produce biofuels.

3. HEAT CHARACTERISTICS OF NUCLEAR ENERGY TO SUPPORT NEGATIVE EMISSIONS TECHNOLOGIES

The performance of various types of NPP concepts is estimated in this section using industry-representative designs based on the literature. In particular, reactor performance in terms of heat temperature and quantity generated is detailed to determine the availability to support the NET processes described in the previous section. The ability of NPPs to provide heat at elevated temperatures was investigated for three general reactor concepts:

- Very High Temperature Reactors (VHTR) cooled by helium with direct helium Brayton cycle energy conversion with nominal outlet coolant temperature and thermal efficiency of 850 °C and 45%, respectively;
- Sodium-cooled Fast Reactor (SFR) coupled to a superheated steam Rankine Cycle with nominal outlet coolant temperature and thermal efficiency of 500 °C and 42%, respectively; and
- Conventional Pressurized light-Water-cooled Reactor (PWR) with saturated Rankine Steam Cycle with nominal outlet coolant temperature and thermal efficiency of ~273 °C and 35%, respectively.

The goals of the analysis presented in this section are to

- Characterize the available temperature regime of nominal heat rejection—this would be considered as “free” heat from the reactor, as it is usually dumped into the environment unused;
- Identify the possibilities of providing process heat at temperatures higher than nominal heat rejection; and
- Quantify the dependency of the reduction of the plant electrical output on the amount of process heat supply using these higher temperature options.

In this work, the heat extraction is done at the energy conversion side of the plant, rather than using the reactor coolant, first to minimize the effect on the reactor design (and possibly safety) and, second, to avoid any possible issues of dealing with radioactive coolant in the carbon capture system⁸.

3.1 VHTR

The analysis for the Very High Temperature Reactor is based on the HolosGen concept of a helium-cooled microreactor [67]. This concept was selected because Argonne has participated in the design of HolosGen through an ARPA-E project [68]. As a part of that design work, a model of the direct helium Brayton cycle for HolosGen was developed and described in the open literature [69, 70], and it is therefore available for the present analysis. The HolosGen Brayton cycle is simulated using Argonne’s Plant Dynamics Code (PDC) [71] for design, control, and transient analysis of Brayton cycles.

The reference design conditions for the HolosGen Brayton cycle are shown in Figure 3-1. The reactor power is 22 MW thermal, which is converted to about 10 MW electric with a cycle efficiency of 44.6%. The Brayton cycle layout is typical for an intercooled direct Brayton cycle, where helium coolant (at 7 MPa pressure) leaves the reactor (at 850 °C temperature) before expanding in the turbine (to 3.5 MPa), driving the generator to produce the electrical output. After the turbine, helium goes through the recuperator, to recover some of the useful thermal energy, before being sent to the cooler (at 125 °C) for the heat rejection to the ultimate heat sink. The helium leaves the cooler at the design temperature of 40 °C and enters two stages of compression, passing through a Low-Pressure Compressor (to 4.9 MPa pressure) and a High-Pressure Compressor (back to 7 MPa), with intermediate cooling between these two stages in the intercooler. The compressed helium goes to the recuperator, then back to the reactor.

⁸ This does not apply to VHTR with direct cycle, as the reactor coolant and energy conversion fluid are the same helium. Helium, however, is not activated by the neutrons and thus does not present a radioactivity risk to the process heat.

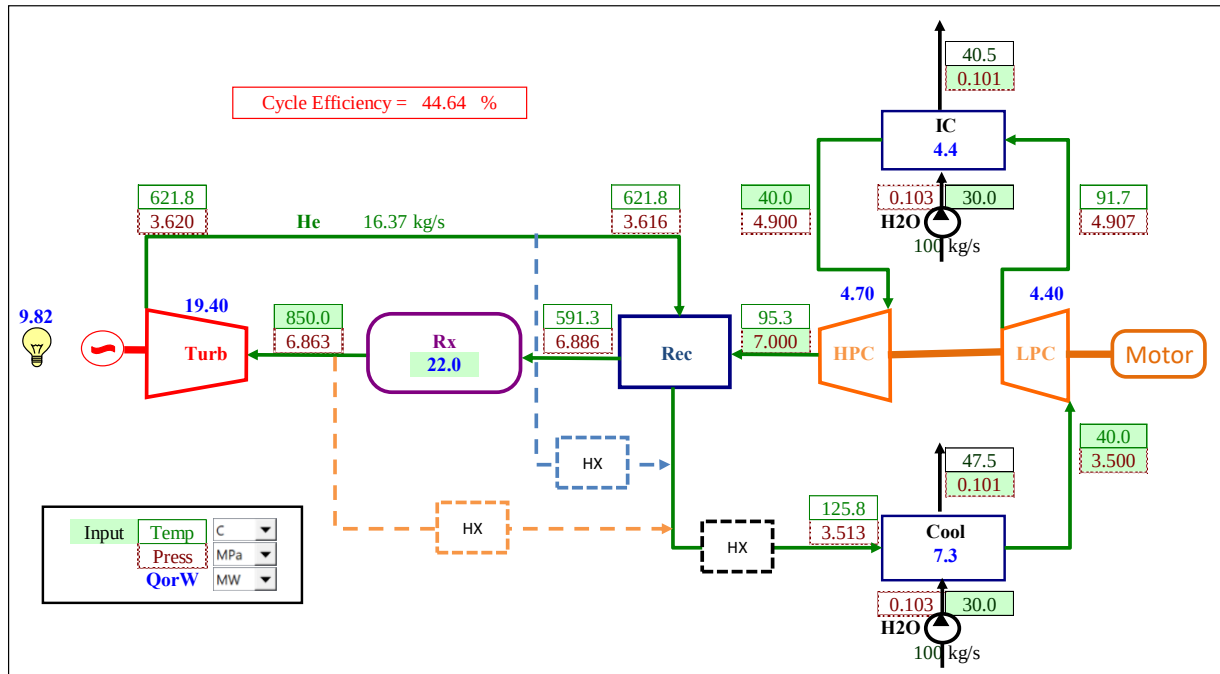


Figure 3-1. HolosGen VHTR reference design conditions.

As indicated in Figure 3-1, 7.3 MW of heat is normally rejected from the cycle in the main cooler between 125 °C and 40 °C, and 4.4 MW is rejected in the intercooler between 92 °C and 40 °C. The helium flow rate is 16.4 kg/s everywhere in the cycle (the dashed branching lines in Figure 3-1 are not activated in the design and are discussed below).

For a comparison with other reactor concepts, which have different power levels, the results in this section will be presented in relative terms, normalized to the total reactor power. For example, all VHTR flow rates will be provided in percent-nominal (%nom) units. From Figure 3-1, the relative nominal flow rate is 16.37 kg/s/22 MWth = 0.744 kg/s/MWth.

Figure 3-1 shows that the Brayton helium cycle has three major options for extracting heat for an external process. These options are shown in the dashed bypass lines with possible HX locations, and include the following:

1. Heat extraction at 850 °C by bypassing some of the flow from the reactor outlet (orange bypass line in Figure 3-1). Note that this option represents the highest available temperature from the reactor.
2. Heat extraction with bypass from the turbine outlet at 620 °C (blue bypass line in Figure 3-1).
3. Indirect heat extraction after either of the bypass lines is merged with the main helium flow before the cooler (black dashed HX symbol in Figure 3-1).

To investigate the effect of heat extraction on the plant electrical output, a series of PDC calculations were carried out with gradual increase in flow in the two bypass lines in Figure 3-1. The reactor heat production is still fixed at 22 MWth, as are the boundary conditions of 850 °C reactor-outlet temperature, 40 °C compressor-inlet temperatures, and 3.5 MPa/7.0 MPa for minimum/maximum cycle pressures⁹. The calculations were still done in the design mode: for example the turbine efficiency was held constant at 90%, and the effects of changing conditions on the component design and performance were ignored. The

⁹ Note that these pressures, and or temperatures, may no longer be optimal for conditions different from the reference design in Figure 3-1. Re-optimizing the reactor and plant design for the new conditions is beyond the scope of this analysis.

last important assumption for the calculations presented here is that any heat in the bypass flow is assumed to be lost for electricity production purposes: it is either used in the process HX or removed from the cycle in the cooler. In other words, no attempts were made to re-use any remaining heat after the working fluid returns from the process HX back to the cycle. Such optimization would depend on the exact conditions of the process heat and therefore could not be generalized in this scoping study.

The main results of the calculations for VHTR are shown in Figure 3-2, which plots the cycle efficiency and plant net electrical output as a function of bypass (extraction) flow rate. Note that the bypass flow is measured relative to the nominal flow rate in Figure 3-1 (0.744 kg/s/MWth). Since the reactor power was fixed, the reduction in the cycle efficiency in the first plot is directly proportional to the reduction in plant electrical output in the second plot. The bypass flow fraction was increased until either zero electrical output was achieved (for the 850 °C case), where the energy produced in the turbine is just sufficient to drive the compressors to circulate the reactor coolant, or (for the 620 °C case) until the bypass fraction increased all the way to 100%, with full reactor flow rate sent to the bypass line. As clearly seen from Figure 3-2, helium extraction at a higher temperature (850 °C) has a greater effect on the cycle efficiency and plant electrical output, as higher-grade heat is diverted from the cycle to the process heat.

Figure 3-2 shows the results of “direct” heat and flow extraction, where the heat is diverted from the cycle in the bypass (extraction) lines. At the same time, the same bypass could be used to increase the cooler-inlet temperature. In this case, it is assumed that no heat is extracted in the bypass line itself, but in another process HX in series with the cooler (or black dashed HX in Figure 3-1 and Option 3 in the above list). The higher the bypass flow fraction, the more high-temperature coolant is sent to the cooler inlet and, thus, the higher the cooler inlet temperature. The results for the corresponding cooler inlet temperature, as a function of the bypass (extraction) flow, are shown in Figure 3-3 (first plot). These results demonstrate that any temperature between the original cooler-inlet temperature of 125 °C and 620 °C could be achieved with these bypass lines (850 °C bypass can only provide temperatures up to 500 °C). The second plot in Figure 3-3 combines the results in the first plot with the plant output from Figure 3-2, and shows the plant electrical output versus cooler-inlet temperature, for each bypass flow. These results demonstrate that for any given intermediate temperature for process heat, it is more efficient to use the turbine-outlet 620 °C bypass option, rather than the high-grade heat from the reactor outlet at 850 °C, as it results in a smaller reduction in the plant output.

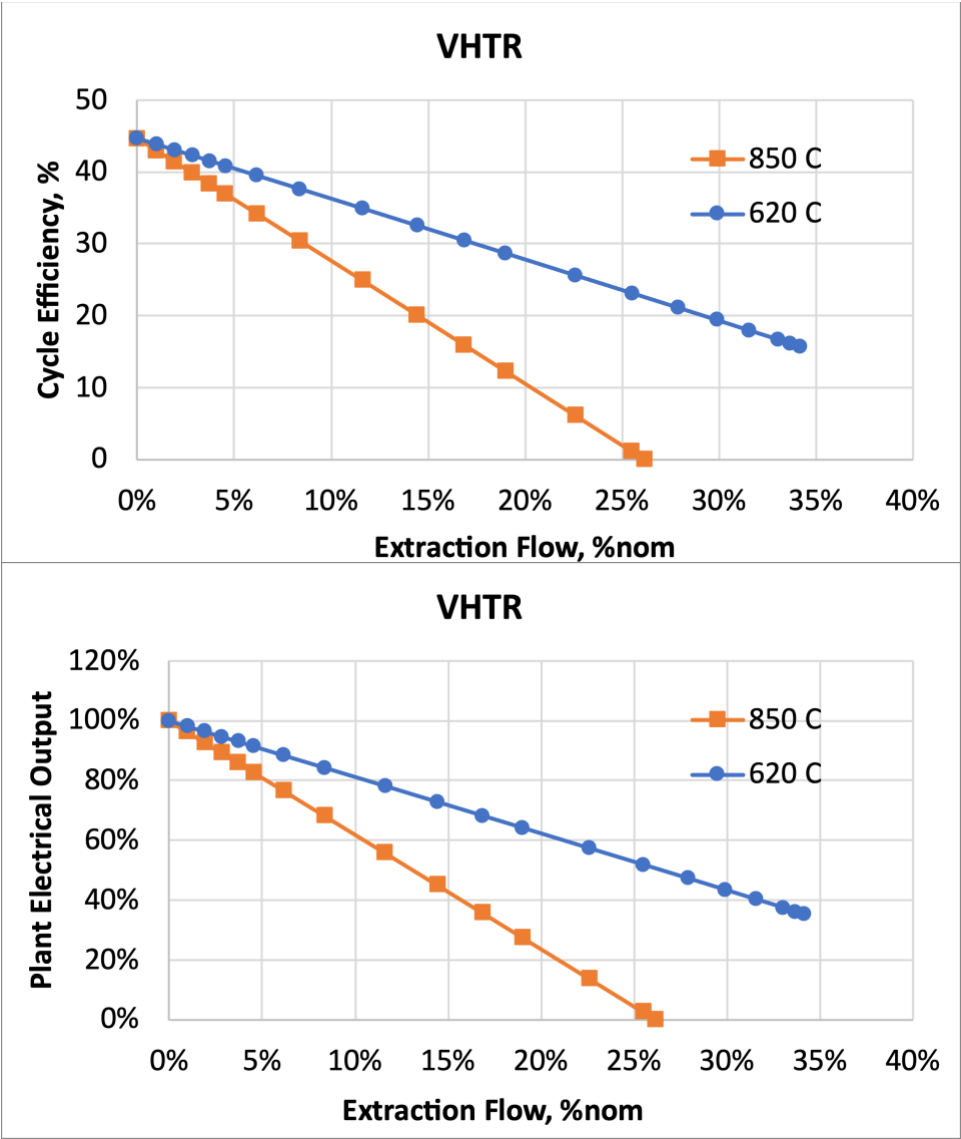


Figure 3-2. Effect of heat extraction on a VHTR.

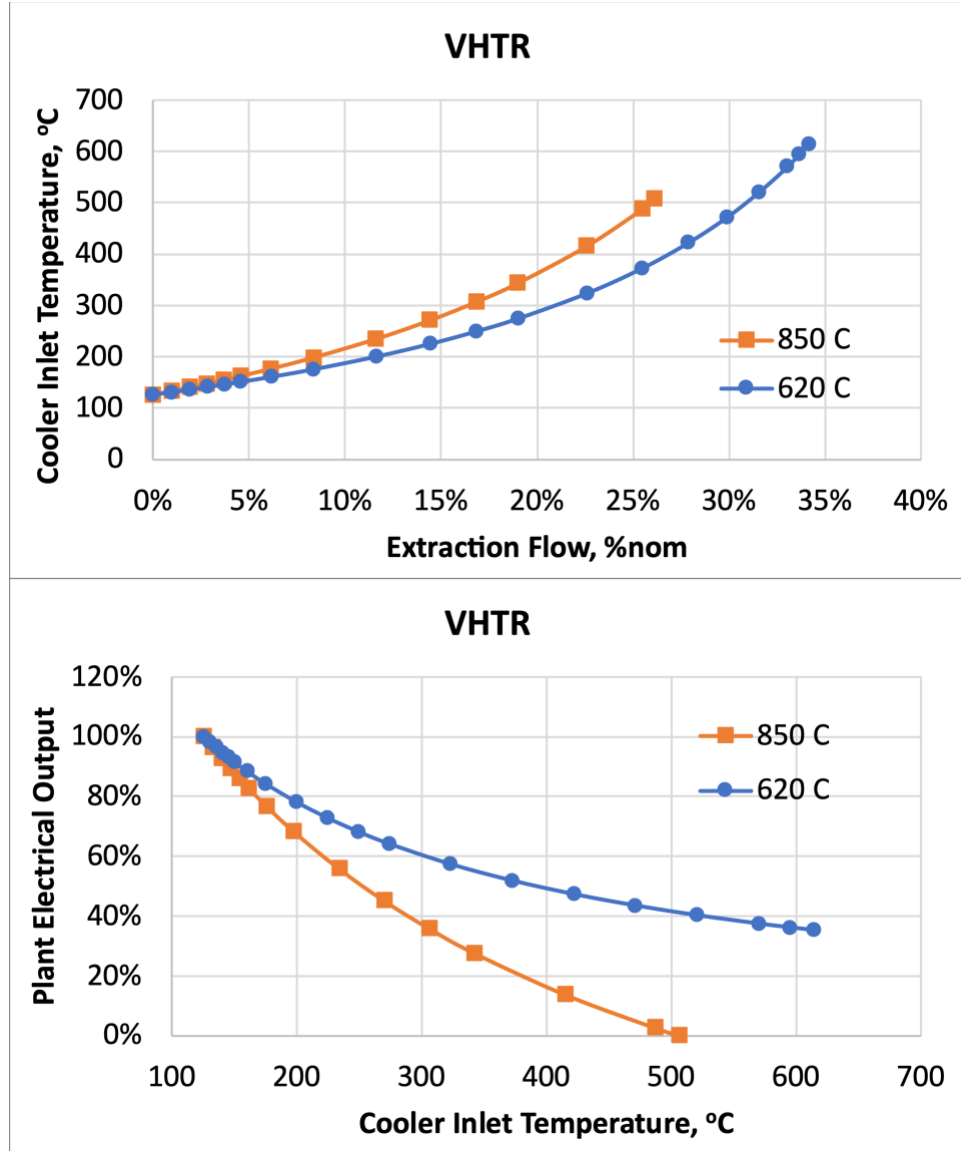


Figure 3-3. Intermediate heat extraction temperatures for a VHTR.

It is important to note that the cycle calculations described here can only provide the inlet condition of the reactor fluid (helium) entering the process-heat HX. How much heat can be extracted (or used by the process) depends on the process itself and, in particular, the minimum temperature requirement for the process. For helium, the extraction heat can be calculated with Equation 5:

$$Q_{extr} = c_p m_{ext} (T_{ext} - T_{min}) \quad 5$$

where:

c_p = helium specific heat (5193 J/kg-K),

m_{ext} = extraction (bypass) flow rate, from Figure 3-2,

T_{ext} = extraction temperature, either 850 °C or 620 °C, and

T_{min} = minimum temperature at which the process can accept heat.

Since that minimum temperature, in general, depends on the process to be used, the amount of heat available to the process is also process-dependent. For the absolute limit, where a process can use heat all the way to the minimum cycle temperature of 40 °C, the amount of heat available to the process is equal to the total heat rejection from the cycle in the cooler and intercooler. That upper limit can be easily calculated as $(1 - \text{cycle efficiency}) \times \text{reactor power}$, with cycle efficiency defined in Figure 3-2.

In addition to the heat extraction options described above, another operating regime is also considered in this study, where the reactor is utilized only to provide heat and not generate any electricity. In this option, most of the balance-of-plant (BOP) components in Figure 3-1 are eliminated. Instead, the coolant from the reactor, at 850 °C, is sent directly to a process HX. Then, the coolant is returned to the reactor by a circulator (or pump). To minimize the effect on the reactor design, the return temperature (or temperature leaving the process HX) is assumed to be the same as the reactor-inlet temperature of 590 °C in Figure 3-1. The coolant will be at approximately the same pressure (around 7 MPa) everywhere in this loop, except for the pressure drops which are compensated for by the circulator. The rest of the BOP components, like the turbine, recuperator, and compressors, are not used in this configuration and no electricity is produced by the plant. This option is therefore referred to as the no-BOP scenario in the rest of this report. The heat rate available in the process HX is equal to 100% of the reactor thermal power (22 MWth in Figure 3-1).

3.2 SFR

A Sodium-Cooled Fast Reactor (SFR) concept is investigated as a representative of advanced reactors with an intermediate (between VHTR and PWR) operating temperature range. The analysis for the SFR is based on the AFR-100 reactor design [72]. A concept of the AFR-100 steam cycle has been developed by Argonne in previous work [73]. The steam cycle model development and the analysis presented in the present work was carried out using GE GateCycle software [74].

The reference design conditions for the AFR-100 steam cycle are shown in Figure 3-4. Steam is provided in the nuclear steam supply system (NSSS) steam generator (SG). The SG heat duty is 250 MW thermal, which is converted to about 105 MW electric with a cycle efficiency of 41.8%. The AFR-100 steam cycle employs two turbine stages – high-pressure turbine (HPT) and low-pressure turbine (LPT), with moisture separation (MSEP) between turbine stages. After the turbine, the flow goes to the condenser (COND), then to a series of feedwater heaters (FWHs), deaerator (DA), and condensate pumps (PUMP), before returning to the SG. The heat in the feedwater heaters is provided by the steam extraction lines from the turbines. The main steam after the SG is at 500 °C and 16 MPa. The main steam flow rate through the SG is 110.8 kg/s. Figure 3-4 also highlights the available steam extraction conditions at intermediate temperatures and pressures, as will be discussed later.

As indicated in Figure 3-4, waste heat is normally rejected from the cycle in the condenser at 46 °C and 0.01 MPa. The condenser heat rejection rate under the nominal conditions is 142.7 MW (57% of reactor power). This heat is assumed in the model as lost to the environment and thus using it, or any part of it, for the process heat would not affect the steam cycle efficiency and plant electrical output in any way.

For a comparison with other reactor concepts, which have different power levels, the results in this section are presented in relative terms, normalized to the total reactor (or SG) power. For example, all SFR flow rates are provided in percent-nominal (%nom) units. From Figure 3-4, the relative nominal flow rate is $110.8 \text{ kg/s} / 250 \text{ MWth} = 0.443 \text{ kg/s/MWth}$.

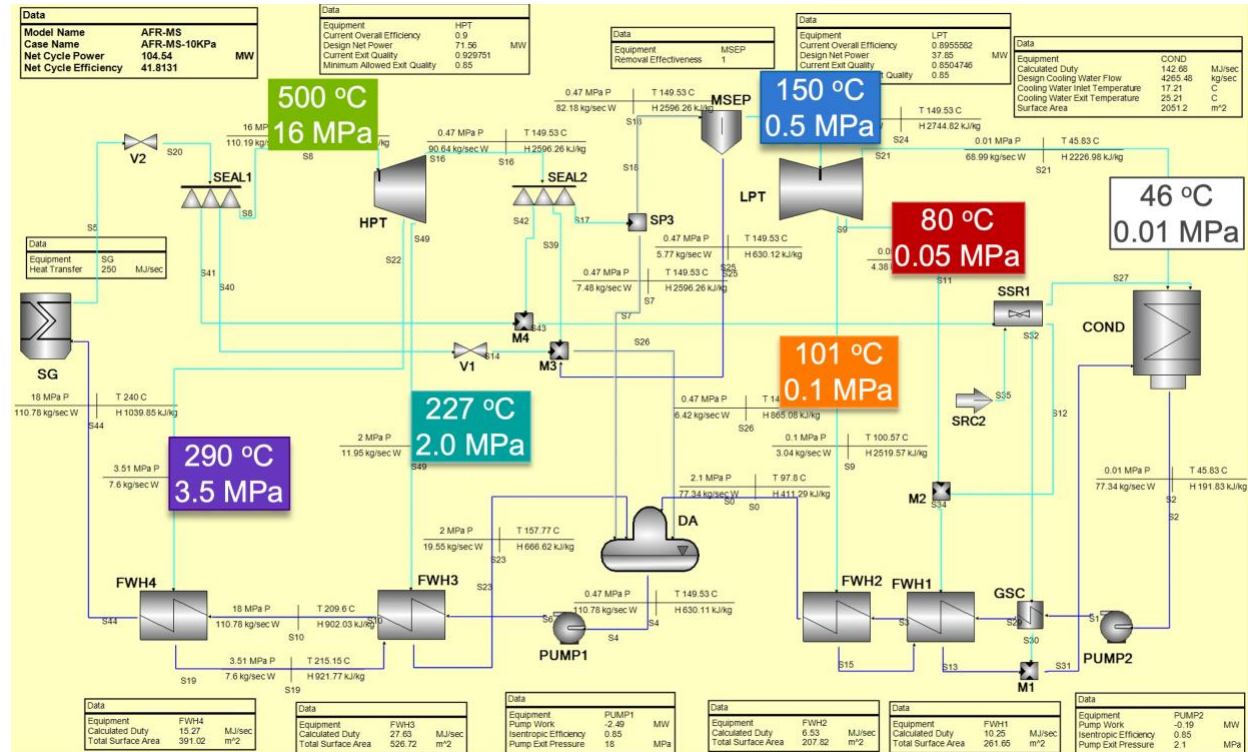


Figure 3-4. AFR-100 SFR reference design conditions and steam extraction options.

To investigate the effect of heat extraction on the plant electrical output, a series of GateCycle calculations were carried out with gradual increase in flow taken from the steam lines in Figure 3-4. These steam lines include the steam supply to the HP and LP turbines, at 500 °C and 150 °C, respectively, as well as steam extraction lines to feedwater heaters from the HPT (at 290 °C and 227 °C) and LPT (at 101 °C and 80 °C). For all these calculations, the steam cycle layout in Figure 3-4 was modified to allow steam extraction for external purposes at various locations. For example, to use the main steam at 500 °C for the process heat, a flow split node was added upstream of the HP turbine. The primary port of that flow split still provided flow to the turbine. However, the secondary port of the flow split was connected directly to the condenser to simulate heat removed from the system and thus lost to electricity production. The mass flow rate in the secondary port for the external steam extraction was gradually increased from 0 (no extraction) for as long as a convergent solution for the entire cycle could still be obtained by the GateCycle. These calculations were then repeated for all available steam options in Figure 3-4.

For the steam extraction calculations, the reactor heat production (and heat addition in the SG) is still fixed at 250 MW_{th}, as are the boundary conditions of 500 °C main steam temperature, 46 °C condenser temperatures, and 0.01 MPa/16 MPa of minimum/maximum cycle pressures. The calculations were done in the design mode: for example the turbine efficiency was held constant at 90%, and the effects of changing conditions on the component design and performance were ignored. Likewise, the feedwater heater calculations were done in the design mode, where the desired outlet temperature (or terminal temperature difference) was specified and was held constant, with the code calculating the required hot-side steam flow rate. As a result of these assumptions, the SG inlet temperature also remains fixed at 240 °C for all steam extraction flow rates. This means, together with the fixed SG heat duty and the outlet temperature, that the steam flow rate in the SG remains fixed at 110.8 kg/s. As in the analysis of other concepts presented in this section, it is assumed that any heat in the extraction flow is lost for electricity production purposes: it is either used in the process HX or removed from the cycle in the condenser. In other words, no attempts were made to re-use any remaining heat after the working fluid returns from the

process HX to the cycle. Such optimization would depend on the exact conditions of the process heat and therefore could not be generalized in this scoping study.

The results of the steam extraction calculations for the AFR-100 SFR are shown in Figure 3-5. The net plant electrical output (in %nom) and the steam cycle net efficiency (in %) are shown as a function of the steam extraction flow rate (in %nom) for all considered steam extraction options from Figure 3-4. The steam at the turbine inlets is shown by the solid lines, while the steam from the turbine extraction pipes is shown by the dashed lines. As expected, diverting more and more steam from the turbine cycle to the process heat results in a decrease in the plant electrical output and the cycle efficiency. Also, similarly to the VHTR results, using a higher steam grade (higher steam temperature) in the process heat leads to a larger decrease in the plant output.

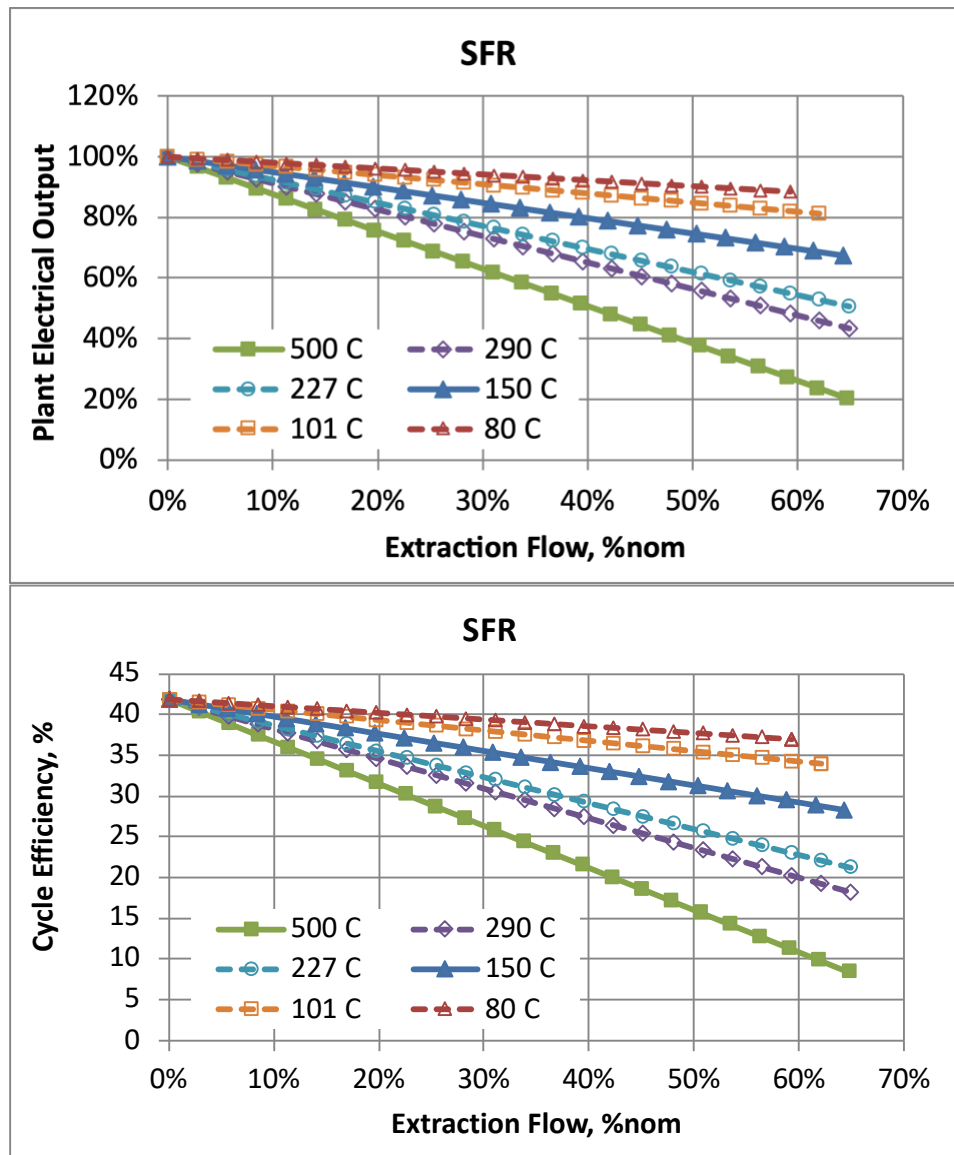


Figure 3-5. Effect of heat extraction on an SFR.

As in the VHTR case, an estimate was made of how much heat is available from extraction lines in each case for the process heat. Again, the actual amount of heat used in the process will depend on the process itself. Consequently, only the maximum available heat is calculated in the work described in this section. That maximum available heat is calculated using the difference in heat capacities (enthalpies) of the extraction flow and the enthalpy of flow going into the condenser (it is again assumed that all heat entering the condenser will be lost to the environment). Thus, the maximum available heat from each steam extraction line is calculated with Equation 6:

$$Q_{max} = m_{ext}(h_{ext} - h_{cond}) \quad 6$$

where:

m_{ext} = extraction flow rate, from Figure 3-5,

h_{ext} = extraction steam enthalpy at the corresponding temperature and pressure, and

h_{cond} = enthalpy at the condenser inlet (46 °C and 0.01 MPa).

The steam enthalpies for the above equation are provided in the GateCycle calculations. The resulting maximum available heat from each steam extraction is shown in Figure 3-6. In the first plot, that maximum heat, normalized to the reactor (SG) power, is plotted against the extraction flow rate. Because higher-temperature steam has higher heat capacity, extraction at higher temperature leads to more heat available to the process, for the same flow rate. In the second plot, the same results are shown as the electrical output as a function of heat removal for the process. The general trend is the same for all extraction options: the more heat is removed from the cycle, the less electricity is produced by the steam turbines.

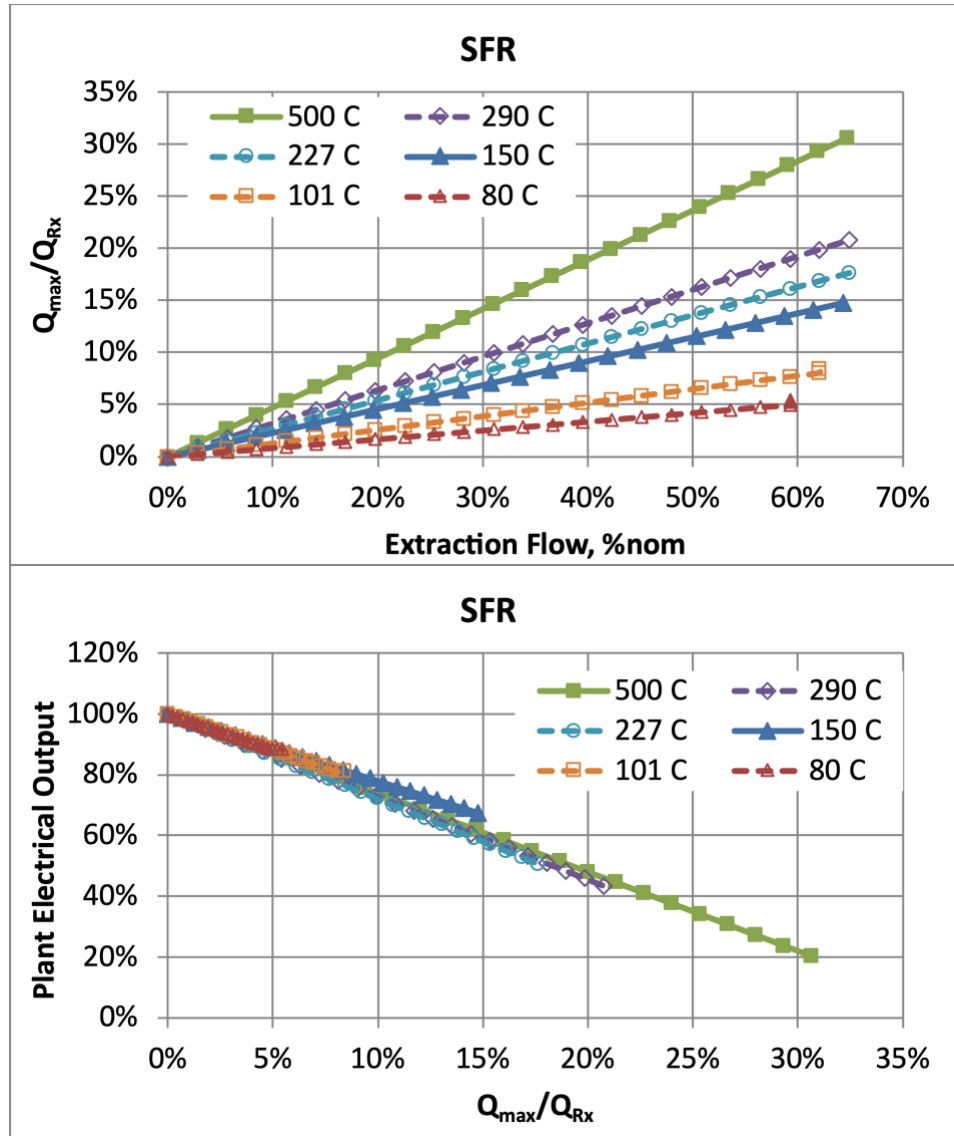


Figure 3-6. Maximum available process heat for an SFR.

3.3 PWR

The Pressurized Water Reactor (PWR) is modeled using the AP1000 design [75]. This model is meant to represent the class of LWRs with lower steam temperatures (compared to the VHTR and SFR). For this work, the AP1000 steam plant was modeled in GateCycle software [74] using the information provided in NRC licensing reports in [76].

The PWR steam cycle plant is shown in Figure 3-7 along with the conditions in the available steam extraction points. The GateCycle model in Figure 3-7 was verified by reaching close agreement between the net cycle output (1200.9 MW) and that provided in [76] (1199.5 MW). The PWR steam layout is close in configuration to that for the SFR in Figure 3-4, with a SG, high- and low-pressure-turbines, condenser, a number of feedwater heaters, and condensate pumps. At the same time, there are a few noticeable differences from the SFR analysis presented in Section 3.2:

- The main steam temperature (273 °C) and pressure (5.7 MPa) are significantly lower than those for the SFR in Figure 3-4;
- The PWR steam cycle uses steam reheaters (RHs) before the LPT; and
- The number of feedwater heaters, and corresponding steam extraction lines from the turbine, is larger for the PWR. That difference results in a larger number of available steam extraction points (9 total: at 273, 241, 231, 207, 258, 167, 128, 96, and 76 °C), as shown in Figure 3-7.

The heat addition rate in the SG is 3,415 MW, and the main steam flow rate is 1880 kg/s, translating to 0.55 kg/s / MWth relative flow rate for comparison with other designs. The steam conditions in the condenser (43 °C and 0.009 MPa) are not that different from those for the AFR-100 SFR. The condenser heat rejection rate under the nominal conditions is 2,178 MW (63.8% of reactor power).

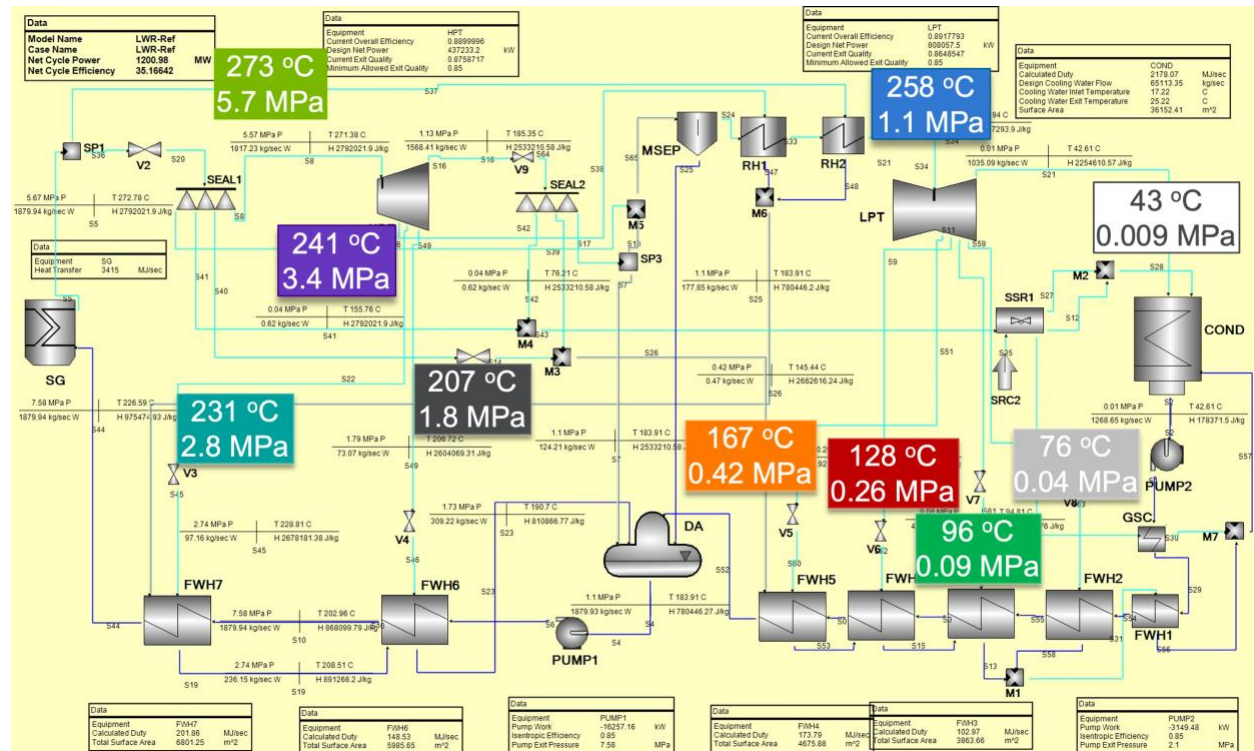


Figure 3-7. AP1000 PWR reference design conditions and steam extraction options.

The analysis of the effect of the steam extraction on the net plant output is very similar to that of the SFR presented above. The same software (GateCycle) in the same mode (design) was used. A fraction of the flow was taken from each extraction point and sent to the condenser. The extraction flow fraction was gradually increased from zero until a converged solution in GateCycle could no longer be obtained. The calculations were repeated for all extraction points identified in Figure 3-7.

The results of the calculations in terms of the net plant output and net cycle efficiency reduction with increase in the extraction flow rate are shown in Figure 3-8. The results for the maximum available heat in the extraction line are provided in Figure 3-9. For the latter calculations, the same equation for Q_{max} listed in the SFR section above was used, but the actual flow enthalpies (and flow rates) were different for the PWR model. Overall, the results for the PWR are similar, in trends, to those described above for SFR.

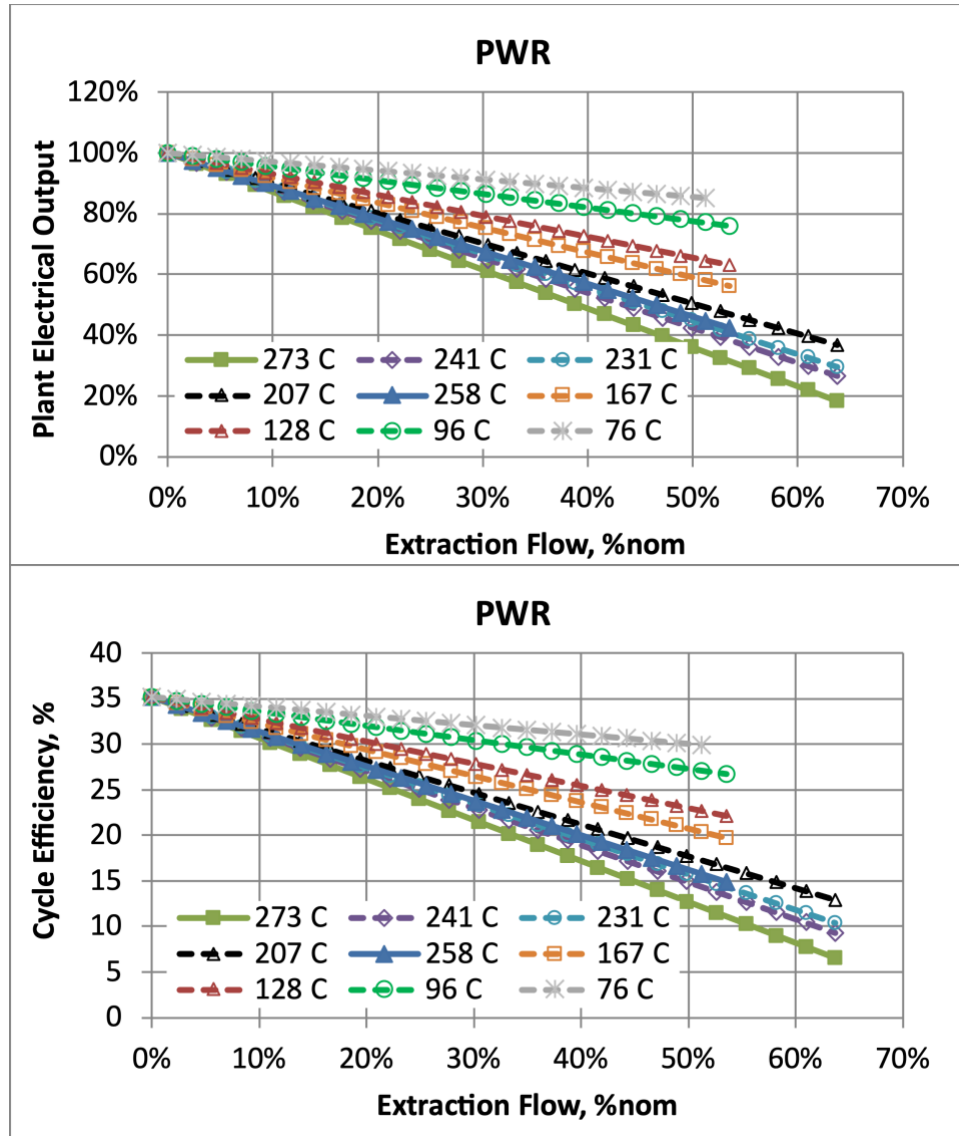


Figure 3-8. Effect of heat extraction on a PWR.

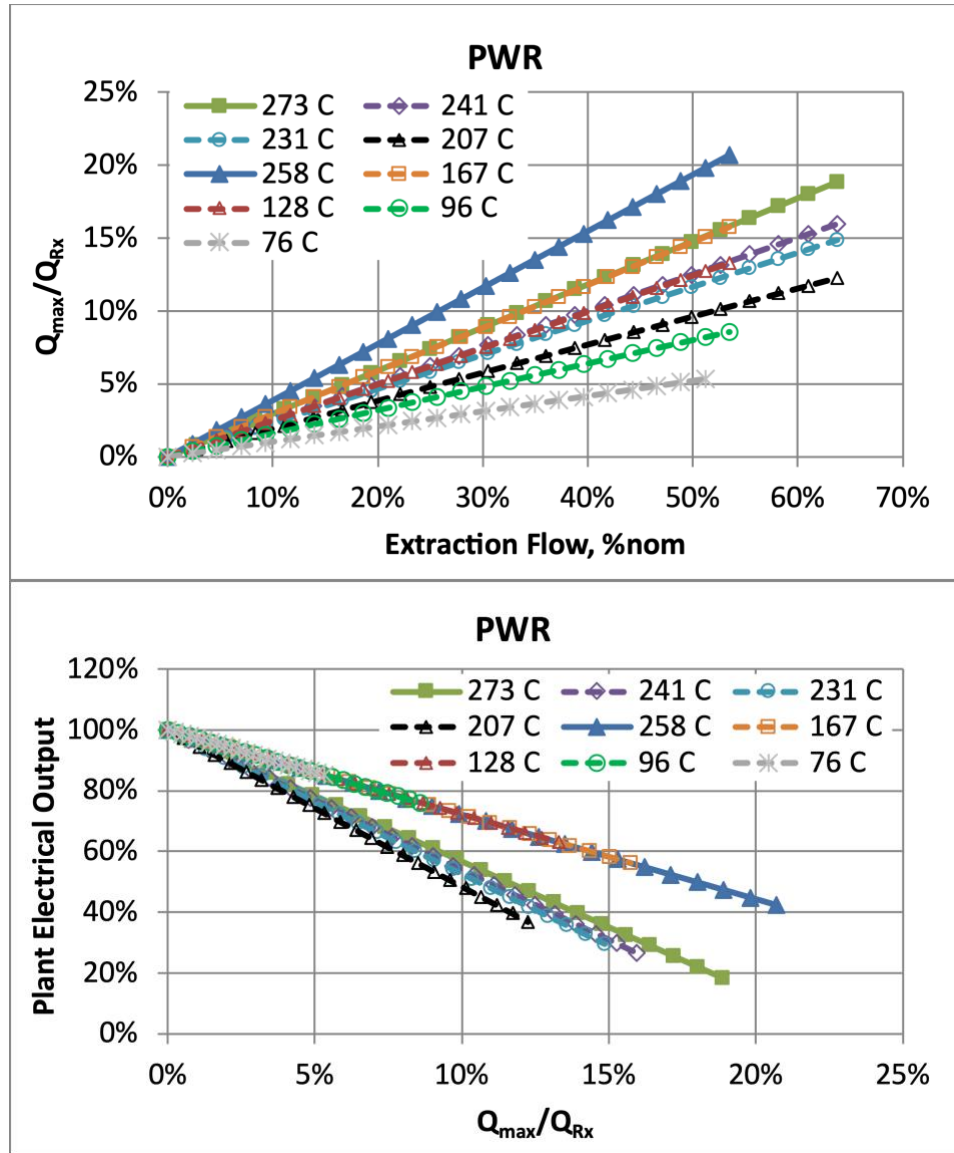


Figure 3-9. Maximum available process heat for a PWR.

3.4 Summary of Heat Characteristics Available with Different NPP Technologies

Several different reactor operating modes (with different quality/quantity of heat available) were selected based on the study described above. The 3 selected NPP operating modes are summarized in Table 3-1 and described as follows:

- Option #1:** The NPP operates for heat generation only, without electricity production. This will be the likely preferred option for PyCCS and Gasification processes. For the PWR and SFR (steam cycles), the temperatures provided are based on the assumption of a steam cycle similar to the reference design, while the absence of BOP assumed in this scenario could provide an opportunity to change the working fluid or conditions (pressure/temperature) of the secondary circuit to better optimize coupling with a NET. The temperatures will remain approximately the same (limited by the primary side), but may still vary significantly. Other working fluids could be envisioned such as pressurized water or molten salt, which could help simplify HX designs.

- **Option #2:** The NPP operates at reduced electrical power with high-temperature heat extracted, leading to reduced thermal efficiency. As discussed in previous sections, a wide range of temperature/pressure conditions are available in different NPP technologies. The ones selected in Table 3-1 represent the optimum conditions obtained to operate S-DAC technologies.
- **Option #3:** The NPP operates at full electrical power; only waste heat can be extracted without an impact on cycle efficiency. This option will likely be the preferred one for the L-DAC, ISC, and EEW processes. In this case, only the steam sent to the condenser is extracted, which does not represent 100% for the PWR and SFR cases, as some of the steam is extracted in feedwater heaters and some of the steam from the SG doesn't reach the condenser.

Other options that would be intermediate between #1 and #3 could be considered: for instance, using L-DAC to extract some high-temperature heat for the calciner operation. Those options are not reported in Table 3-1, but could be derived from the detailed analysis reported in previous sections.

In previous sections, the analyses were based on different NPPs with various power levels ranging from 10 MWe to 1200 MWe. To compare the heat supply capabilities of different reactors, results for NPPs with a uniform 1 GW of thermal power are displayed in Table 3-1, under the assumption that BOP performance and characteristics scale linearly with power. The resulting PWR, SFR and VHTR technologies used for maximum electricity production (Option #3) generate 352 MWe, 420 MWe and 446 MWe, respectively. Consequently, 1-GWth plants will be considered in techno-economic analysis of nuclear NET processes in the following sections.

Table 3-1. Temperature and electricity production with different reactor technologies.

	PWR	SFR	VHTR
Direct heat temperature (temperature on the secondary side)	273 °C	500 °C	850 °C
Waste heat temperature	43 °C	46 °C	125 °C
Cycle efficiency*	35.2%	42.0%	44.6%
Option #1 (high-temp. heat utilization - no BOP)	100% of steam flow extracted at 273 °C, 0 MWe produced	100% of steam flow extracted at 500 °C, 0 MWe produced	100% of helium flow extracted at 850 °C, 0 MWe produced
Option #2 (optimized for S-DAC)	18.6% of steam flow extracted at 167 °C and 0.43 MPa, 297 MWe produced	16.8% of steam flow extracted at 150 °C and 0.5 MPa, 381 MWe produced	100% of helium flow extracted at 125 °C (waste heat), 446 MWe produced
Option #3 (waste heat utilization)	55.1% of steam flow extracted at 43 °C and 0.01 MPa (waste heat), 352 MWe produced	62.3% of steam flow extracted at 46 °C and 0.01 MPa (waste heat), 418 MWe produced	

* The “cycle” efficiency provided does not include house-load operation, which is approximated at 3% of thermal power (30 MWe).

4. DETAILED TECHNO-ECONOMIC FEASIBILITY STUDY OF NUCLEAR ENERGY WITH DIRECT AIR CAPTURE SYSTEMS

This section reports on the CO₂ capture potential of DAC systems paired with nuclear power as a heat and power source. Previously developed performance and cost estimates for L-DAC and S-DAC systems are adapted for the integrated NPP & DAC cases [13] [14].

For the L-DAC cases, most sub-systems were modeled based on Carbon Engineering process representations [77]. For the S-DAC case, a generic solid sorbent was used, characterized by average properties of published sorbents at the time the study was conducted; the system configuration was designed to represent the most reasonable conceptual configuration if these systems were to be deployed in the near term.

Vendor quotes and engineering, procurement, and construction firms' industrial experience were used to model the BOP. Independent operating and capital cost estimates based on commercially available technology from reputable suppliers were developed by Black & Veatch using their in-house cost estimating references. The capital cost estimates represent an AACE International Class 5 estimate, with an uncertainty range of +/-50 percent. The emissions results reported here represent only emissions inside the plant fence; a full life cycle analysis was not performed as part of the reference case studies. The performance and cost results reported here are not based on optimized designs of actual plants, but represent the conceptual potential of newly built integrated NPP&DAC systems. (This study does not consider the retrofit of existing NPPs.)

After discussion of the cost of the L-DAC (in Section 4.1) and S-DAC (in Section 4.2) systems, and their relative performance, the costs of the NPP&DAC systems are computed and the market potential is discussed in Section 4.3.

4.1 Liquid Solvent DAC

As described in Section 2.1.1, all the CO₂ captured from air in an L-DAC system is converted to limestone (CaCO₃). Calcination of limestone is done to release the CO₂ and convert the sorbent to CaO, which is recirculated to the DAC reactor. The calcination process requires heat at a temperature higher than 850 °C, typically 900 °C, which is usually supplied by oxy-combustion of natural gas. High-purity CO₂ generated as the combustion product, and the CO₂ released in the calcination reaction, are combined within the calciner. After the water vapor is condensed from the product gases, the CO₂ stream is further purified and compressed to pipeline pressure. The L-DAC system also needs auxiliary power to supply the electrical energy for pumps and compressors.

4.1.1 Description of NPP&L-DAC Systems

Among the NPP scenarios described in Table 3-1, the highest temperature at which heat can be utilized from the NPP is 850 °C, in operating mode #1 of the VHTR. The ideal case for using this NPP as a source of heat for the calcination reaction would be to mix helium directly with CaCO₃, to avoid heat losses from indirect heat transfer. Even assuming perfect heat transfer from direct mixing, the resulting CO₂ would be diluted with helium, whose separation would require additional energy. Given these limitations, it was decided to use only electricity from the NPP for the L-DAC system, while the calcination heat is supplied by oxy-combustion of natural gas. Since the CO₂ from oxy-combustion is also captured, the process does not result in significant CO₂ emissions. The electricity from the NPP is used primarily to supply the air separation unit (ASU) and CO₂ compressors. Since no heat is used from the NPP, operating mode #3 of all the reactor cases is used for L-DAC. Hence, the NPP will produce maximum electricity, and no heat is extracted. Other options discussed in Section 2.1.1.2 where the NPP generated heat or electricity is used to reduce the need for natural gas oxy-combustion in the calciner will be considered for future work.

4.1.2 Design L-DAC Case

The component modeling of the L-DAC system is based on previous NETL studies [13] to achieve a net CO₂ removal rate of 1 million tonnes/yr in the design case. This amount includes the CO₂ captured from air (74.5% capture rate) as well as CO₂ generated by oxy-combustion of natural gas in the calciner. The case study is an example configuration for a solvent-based DAC plant and does not represent an optimized design. While the NETL study used a natural gas combined cycle (NGCC) to supply the electrical energy for the DAC system, in the present analysis only the DAC system is modeled.

Table 4-1 shows the performance results for a 1 Mt CO₂/yr design plant; this size will be further adjusted to NPP sizes afterward. To achieve a net removal of 1 million tonnes/yr, a total of 1,284,030 tonnes/yr of CO₂ is captured, mainly to compensate for the CO₂ generated from natural gas combustion and for the CO₂ emitted in the compression and dehydration processes. The main auxiliary loads of the plant are also listed in the table, with the CO₂ compressor and ASU being the biggest consumers. The total auxiliary load is close to 42 MWe. The waste heat from the DAC process also generates close to 7 MWth of steam power, resulting in a net electrical power requirement of 35 MWe (for this 1 Mt CO₂/yr plant). The natural gas energy input, based on higher heating value (HHV), is 178 MWth.

Table 4-1. Performance results for the design L-DAC case (1 million tonnes/yr net capture).

CO₂ Balance	
Net CO ₂ Captured [tonnes/yr]	1,000,000
CO ₂ Captured from Air [tonnes/yr]	1,000,320
CO ₂ Emitted [tonnes/yr]	320
CO ₂ Captured from Calciner [tonnes/yr]	283,710
CO ₂ to Storage [tonnes/yr]	1,284,030
Auxiliary Loads	
DAC Air Fan Load [MWe]	6.73
Pellet Reactor Pumps [MWe]	4.46
ASU [MWe]	10.89
CO ₂ Compressor Load [MWe]	17.88
DAC BOP Load [MWe]	1.84
DAC Total Load [MWe]	41.84
Steam Turbine Power [MWe]	6.67
Net Power Required [MWe]	35.17
Natural Gas HHV Input [MWth]	178
Costs	
Overnight Capital Cost [\$M]	1,133
Fixed Operation & Maintenance Costs [\$M/yr]	31.51
Variable Operation & Maintenance Costs [\$M/y], 100% Capacity Factor	76.87
Fuel Costs [\$M/yr], 100% Capacity Factor (Natural gas at \$4.42/MMBtu)	19.96

Table 4-1 also shows the capital and Operation and Maintenance (O&M) costs of the design L-DAC system. The total overnight capital cost (OCC) of the L-DAC plant is \$1,133M. This figure includes the bare erected cost of the plant, engineering and home office fees, process and project contingencies, and owner's costs. The DAC system itself contributes 83% of this cost, while the rest is the BOP (ASU, cooling water systems, etc.). Almost 75% of the Variable O&M (VOM) cost is for DAC chemicals, making it the biggest contributor to the O&M costs. Natural gas costs are almost \$20M/yr.

4.1.3 Cost Estimates for L-DAC Sized with NPP

The power available from the NPP concepts, re-normalized over 1 GWth in Table 3-1, are 322 MWe, 390 MWe, and 416 MWe for the PWR, SFR, and VHTR, respectively. For the design L-DAC case of 1 M tonnes/yr, the electrical power requirement is 35 MW, which is an order of magnitude lower than the power available from NPPs considered in this section. This means that the CO₂ capture potential of DAC using electricity from the NPPs is much higher. Table 4-2 shows the CO₂ capture capacity of these plants to be between around 12 and 15 million tonnes/yr. This size for a single DAC plant is not feasible with current technology. Two alternative scenarios can be assumed for cost estimation: (1) a number of (12 to 15) modular plants of 1 million tonnes/yr capture capacity each will be built, with costs scaling linearly with CO₂ capture rate; or (2) a large DAC plant will be built, with costs scaling using a power law on the basis of CO₂ capture rate. These two scenarios are the likely bounding cases for L-DAC costs powered by nuclear energy.

Table 4-2. Costs of L-DAC plants powered by electricity from NPPs.

Case	PWR	SFR	VHTR
Power Available for DAC [MWe]	322	390	416
CO ₂ Capture Capacity [M tonnes/yr]	11.8	14.2	15.2
Natural Gas HHV Input [GWth]	2.1	2.5	2.7
Costs			
OCC (Modular) [\$M]	\$13,315	\$16,127	\$17,203
OCC (Scaled) [\$M]	\$4,969	\$5,575	\$5,795
FOM (Modular) [\$M/yr]	370	449	478
FOM (Scaled) [\$M/yr]	183	212	223
VOM (100% capacity factor) [\$M/yr]	903	1,094	1,167
Fuel Cost (100% capacity factor) [\$M/yr]	235	284	303

Table 4-2 shows the costs of L-DAC with NPP using the modular and scaled approaches. An exponent of 0.6 is used for scaling the capital costs on a CO₂ capture capacity basis. Since some Fixed O&M (FOM) costs depend on capital costs, those are also scaled accordingly. Hence the OCCs are in the range of about \$13.3 billion to \$17.2 billion for the modular approach, and between \$5 billion and \$5.8 billion for the scaled approach. It may be noted that modular plants do not assume any shared equipment or cost reductions caused by learning-by-doing. Hence, the modular costs reported here are to be treated as the highest possible costs incurred by modular building. It may also be noted that the location of the DAC plant is not explicitly considered in this analysis. It is highly unlikely that a DAC plant capable of capture of near 10 million tonnes/yr will be built in one geographical location, because of the huge volume of air intake. In this light, the costs reported here are to be seen as indicative of the potential of conceptual DAC systems powered by nuclear energy, with a wide band of uncertainty.

Future improvements in L-DAC systems, mainly pertaining to the high-temperature heat requirement, would help drive down the costs of NPP&DAC integrated plants. L-DAC options include the use of an

electric calciner, or a solvent regeneration system that does not require such a high temperature. NPP plants, particularly the VHTR cases, could consider higher-temperature operations [78], which would allow heat integration with the high-temperature calcination reaction. These options could be considered for future studies, depending on L-DAC technological improvement.

4.1.4 CO₂ Capture Performance

Table 4-2 shows the capture efficiency of the integrated NPP&L-DAC plants, calculated as the tonnes of CO₂ removed per unit thermal energy input from the nuclear plant and the total thermal energy input (nuclear + natural gas). All the nuclear plants are based on 1 GWth input. Using this as the basis, the PWR&L-DAC plant can achieve a capture efficiency of 1,342 tonne/GWhth (GWh thermal¹⁰), while the SFR&L-DAC and VHTR&DAC plants have capture efficiencies of 1,625 tonnes/GWhth and 1,733 tonnes/GWhth, respectively. Since the L-DAC systems are scaled mainly on electrical energy from NPPs, the trend in CO₂ capture efficiency shows the effect of increasing NPP efficiency by converting thermal energy to electrical energy. When the thermal energy input from natural gas is also considered, the efficiency values drop by more than a factor of 3. The resulting capture efficiencies are 434 tonnes/GWhth, 460 tonnes/GWhth and 469 tonnes/GWhth for PWR, SFR and VHTR cases, respectively. Thus, the trend of efficiency improvement remains the same for the three NPP reactor types.

4.2 Solid Sorbent DAC

This section presents an assessment of the performance and cost of a generic sorbent-based S-DAC system when integrated with an NPP. The sorbent represents an approximate average of reported material performance in the literature, but is not reflective of any one material type or functionalization approach. This model is based upon a previous NETL study [14].

Figure 4-1 shows a simplified flowsheet of the S-DAC system modeled here. Ambient air is sent through fans and a duct system to distribute air to the DAC adsorber vessels. During steady-state operations, 90% of the vessels will be operating in adsorption mode (1-hour cycle) and receiving air from the fans. The remaining adsorption vessels will be in desorption mode (0.1-hour cycle). Desorption is carried out by extracting heat from condensing low pressure steam (at approximately 0.5 MPa and 150 °C) in an indirect HX. The SFR and PWR systems provide this steam, while in the case of VHTR, steam is replaced with helium. The product CO₂ is pulled from the adsorber vessels to the CO₂ compressor, where it is compressed to 15.2 MPa.

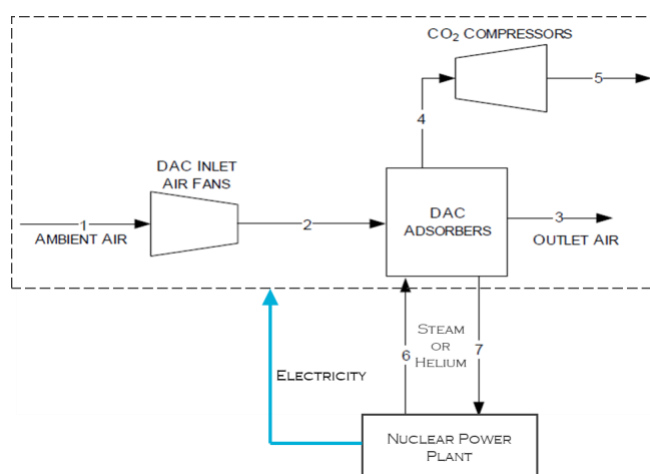


Figure 4-1. Simplified flowsheet of solid sorbent DAC system integrated with an NPP.

¹⁰ 1 GWh thermal (GWhth) is also equal to 3.6 TJ

4.2.1 Description of NPP&S-DAC Systems

Unlike the L-DAC system described earlier, both heat and electricity from the NPP can be used for the S-DAC system. Among the scenarios described in Table 3-1, Options #2 for the PWR and SFR have steam extracted at temperatures and pressures closest to the design conditions of the DAC system. Hence, those are used for NPP-DAC integration. For the VHTR, Options #2 and #3 are equivalent, since helium waste heat is available at 125 °C, which is close to the temperature required for S-DAC. The amount of steam extracted from the PWR and SFR is determined such that the electrical power produced by the NPP matches the power required by the S-DAC system. Table 4-3 shows the inputs used to model the S-DAC system, and their performance and costs.

The results show that heat integration with NPPs has the potential of achieving CO₂ removal capacities of more than 1 million tonnes/yr for 1 GW thermal NPP systems. Because the SFR has greater steam availability than the PWR, the amount of CO₂ captured is also much higher: 1.36 M tonnes/yr in the SFR case compared to 1.04 M tonnes/yr in the PWR case. The quantity of waste heat and electricity available from the VHTR is even higher, leading the VHTR to display the highest CO₂ capture potential (1.46 M tonnes/yr). The main auxiliary load of the DAC plant is for air fans. As mentioned before, the DAC system is sized such that the power available from the NPP matches the auxiliary load of the DAC system. Bigger DAC systems would require additional electrical power purchased from the grid. Hence, for the PWR and SFR cases, there is no power output from the NPP because all the generated electricity is used for the DAC system auxiliary load. In contrast, for the VHTR plant, there is a net electrical power output (42 MW) even after utilizing all the waste heat. Unlike the L-DAC system, there is no additional natural gas requirement for the S-DAC cases.

Table 4-3. Inputs, performance and costs of S-DAC systems.

NPP Case	PWR	SFR	VHTR
Fluid	Steam	Steam	Helium
Inlet Temperature [°C]	167	150.6	125
Inlet Pressure [MPa]	0.43	0.47	3.5
Flow Rate [kg/s]	105	141	744
Outlet Temperature [°C]	146	149	40
Outlet Pressure [MPa]	0.41	0.45	3.36
Power Available for DAC [MW]	267	351	416
Performance			
CO ₂ Capture Capacity [M tonnes/yr]	1.04	1.36	1.45
DAC Air Fan Load [MW]	254	333	355
CO ₂ Compressor Load [MW]	13	17	18
DAC BOP Load [MW]	0.55	0.42	0.44
DAC Total Load [MW]	267	351	374
Net Power Output [MW]	0	0	42
CO ₂ Capture Efficiency [tonnes/GWhth-Total]	118	155	165
Costs			
OCC [\$M]	1,461	1,820	2,010
FOM [\$M/yr]	30.33	37.18	40.70
VOM (100% Capacity Factor) [\$M/yr]	327	394	431
Fuel Costs (for S-DAC) [\$M/yr]	0	0	0

4.2.2 Cost Estimates for S-DAC

Table 4-3 also shows the capital and O&M costs of the S-DAC cases. All the costs scale with the amount of CO₂ captured, with the PWR plant having the lowest OCC (\$1,461M) and the VHTR having the highest OCC (\$2,010M). This figure includes the bare erected cost of the plant, engineering and home office fees, process and project contingencies, and owner's costs. The DAC system itself contributes 93% of this cost, while the rest is the BOP (cooling water systems, etc.). Those balance-of-plant components may be double-counted, as one could leverage those components from the NPP, which will make the OCC estimate for the NPP&DAC systems slightly conservative. Almost 97% of the VOM is for the DAC sorbent, whose price is assumed to be \$400/ft³, with full replacement once a year.

Future improvements in S-DAC systems, mainly pertaining to sorbent design, would help drive down the costs of NPP&DAC integrated plants. Cheaper sorbents and/or sorbents with longer lifetimes would reduce the VOM of the S-DAC systems. Lower regeneration temperature would enable the use of waste heat from PWR and SFR as well, which would improve the overall efficiency of the process.

4.2.3 CO₂ Capture Performance

Table 4-3 shows the capture efficiency of the integrated NPP&S-DAC plants, calculated as the tonnes of CO₂ removed per unit thermal energy input to the nuclear plant. Unlike the L-DAC cases, there is no other thermal energy input for the S-DAC cases. Using 1 GWth of nuclear energy as the basis, the PWR-DAC plant can achieve a capture efficiency of 118 tonnes/GWhth, while the SFR&S-DAC and VHTR&S-DAC plants have capture efficiencies of 155 tonnes/GWhth and 165 tonnes/GWhth, respectively. Since the S-DAC systems are designed to mainly match the electrical energy from NPPs, the trend in CO₂ capture efficiency shows the effect of increasing the NPP's efficiency at converting thermal energy to electrical energy. Compared to the L-DAC cases, the CO₂ capture efficiency of S-DAC cases is much lower.

4.3 Discussion on Competitiveness of NPP&DAC Processes

In previous sections, the DAC systems were coupled with an NPP and their cost and CO₂ capture performance were assessed. The costs of the combined NPP&DAC systems are derived in this section to estimate the competitiveness of this system for CO₂ capture, and compare it to that of non-nuclear energy sources that were previously evaluated by NETL [13, 14]. This evaluation sheds light on the ability of NPP&DAC systems to compete in different CO₂ markets described in Section B-2.

4.3.1 Cost Estimates from Various Coupled NPP&DAC Systems

The summary breakout of cost estimates for NPP concepts considered for detailed techno-economic analyses are shown in Table 4-4 and applied to 1-GW thermal reactors based on their base-case thermal efficiency as shown in Table 3-1. Those cost estimates are coming from the DOE-NE SA&I Cost Basis Report [79]. It should be noted that this estimated OCC is much smaller than the value found for some recent NPP construction projects in the U.S. and Western Europe (such as the Vogtle power plant). This is because the OCC estimate assumes well-managed construction projects without cost overruns due to design changes throughout construction. The O&M expenditures are broken down into VOM, FOM, and Fuel Costs. The fuel cost estimates were obtained in [80]. Both the NPP and DAC systems assume Nth of a kind costs.

Table 4-4. Cost assumptions for different reactor technologies.

Reactor Technology (\$2020)	PWR	SFR	VHTR
OCC [\$/kWe]	\$4,572	\$4,912	\$5,857
VOM [\$/MWhe]	\$2.00	\$2.00	\$2.07
FOM [\$/kWe-yr]	\$80.00	\$86.00	\$96.64
Fuel Cost [\$/MWhe]	\$10.52	\$15.38	\$11.46
LCOE* [\$/MWhe]	\$72	\$80	\$87

* Assumes 90% capacity factor, 60-year plant lifetime, 6.2% interest rate, 5-year construction time.

The levelized cost of electricity (LCOE) was computed for each NPP system to compare this metric to the assumed electricity prices discussed in Section B-1. The NPP LCOEs are larger than the assumed wholesale price (\$33.7/MWh¹¹), which means the utility would need to rely on other sources of revenues such as capacity markets, Production Tax Credits, zero-emission credits, etc., to justify financing a new NPP project. From the perspective of the DAC system, it would be less expensive to purchase electricity from the grid should the electricity purchase price be lower than the NPP LCOE, rather than build an NPP onsite for electricity production. However, the DAC system would then have to compensate for the CO₂ emissions produced from the grid. Moreover, the S-DAC plants would have to account for the costs of on-site steam generation. Hence, these scenarios were not considered in this study.

Using the NPP and DAC estimates obtained in previous sections, the cost of the coupled NPP&DAC systems were computed. As previously discussed, the NPP is sized at 1 GW thermal, and each DAC system is sized to take maximum advantage of the NPP output in terms of heat and electricity. The capital and operating costs of these systems are summarized in Table 4-5, assuming a 90% capacity factor. For both DAC and NPP, the CAPEX is calculated based on a 5-yr construction time and a 6.2% interest rate. The annualized CAPEX is reported in Table 4-5, assuming the lifetimes for NPP and DAC systems are fixed at 60 and 30 years, respectively.

The DAC systems are very expensive technologies, even when compared with the cost of a newly built NPP. The annualized CAPEX of the NPP&S-DAC system is twice the NPP-only cost, while the NPP&L-DAC systems has an annualized CAPEX that is 3 to 10 times (depending on scaling factor) larger than the NPP cost. The OPEX of the NPP&DAC system are significantly larger than that of the NPP-only system, by a factor of 15–21 with L-DAC and a factor of 5–6 with S-DAC.

¹¹ Average locational marginal price calculated on the past 5 years (2015-2019) in all US regions

Table 4-5. Capital and operating costs of the NPP (sized at 1 GWth) and DAC systems.

Reactor technology	PWR	SFR	VHTR
NPP only			
OCC [B\$]	1.61	2.05	2.61
CAPEX [M\$/yr]	119	152	193
VOM [M\$/yr]	5.55	6.59	7.28
FOM [M\$/yr]	28.2	36.0	43.1
Fuel cost [M\$/yr]	29.2	50.7	40.3
NPP & L-DAC system			
OCC [B\$]			
• Modular	14.9	18.2	19.8
• Scaled	6.58	7.63	8.41
CAPEX [M\$/yr]			
• Modular	1,268	1,543	1,677
• Scaled	548	633	693
VOM [M\$/yr]	831	1006	1074
FOM [M\$/yr]			
• Modular	398	484	522
• Scaled	212	248	266
Fuel cost [M\$/yr]	240	306	313
NPP & S-DAC system			
OCC [B\$]	3.07	3.87	4.62
CAPEX [M\$/yr]	245	309	367
VOM [M\$/yr]	301	362	397
FOM [M\$/yr]	58.5	73.1	83.8
Fuel cost [M\$/yr]	29.2	50.7	40.3

4.3.2 Market Analysis of NPP&DAC Processes

4.3.2.1 Estimated Performance of NPP&DAC Processes

The performance of the coupled NPP&DAC systems in terms of electricity produced and quantity and cost of CO₂ captured is summarized in Table 4-6. The economic performance metric used to assess cost of this process is the levelized cost of DAC (LCOD), which estimates averaged cost of the full NPP&DAC system per net tonnes of CO₂ captured from air. This metric can be used to assess the competitiveness of the process when compared to expected revenues from carbon credits, offset markets, or other commodity markets discussed in Section B-2. The LCOD is evaluated based on Equation 7, where the different parameters are shown in Table 4-5. Q_{CO_2} is the annual net CO₂ captured from air, as shown in Table 4-6.

$$LCOD[\frac{\$}{tCO_2}] = \frac{CAPEX[\$/yr] + FOM[\$/yr] + VOM[\$/yr] + FuelCost[\$/yr]}{Q_{CO_2}[tCO_2/yr]} \quad 7$$

This LCOD estimate is currently missing the cost for CO₂ transportation and storage (estimated at \$10–22/tCO₂ [13], [14]), which depends on site location and proximity to geological formation, unless the CO₂

is sold as a commodity to nearby industry. The LCOD calculation assumes 90% capacity factor for the NPP&DAC system.

Even though the L-DAC has much higher capital and operating costs than the S-DAC when sized for a 1-GW thermal reactor, its CO₂ capture potential is significantly higher (x10), resulting in a smaller LCOD by a factor of 2–4. This difference in CO₂ capture performance is, however, partly explained by requirements of the calciner in the L-DAC system for natural gas combustion. The NPP cost contribution to the LCOD is also illustrated in Figure 4-2.

The LCOD obtained does not vary significantly with the different NPP types: the improved capture efficiency obtained from higher-temperature reactors (SFR and VHTR) is offset by their assumed higher capital and operating costs. This conclusion considers the fact that the VHTR is providing “free” waste heat, while the extraction of usable heat from the SFR and PWR penalizes their system thermal efficiency. The VHTR&S-DAC system does generate some excess electricity that may result in additional revenues from the grid. However, those are expected to be small when compared to CO₂ credit revenues, as further discussed below.

Table 4-6. Performance comparison of coupled NPP (1-GWth) and DAC systems.

Reactor Technology	PWR	SFR	VHTR
NPP only			
Electricity production [MW]	322	388	416
NPP & L-DAC			
Electricity production [MW]	0	0	0
CO ₂ capture [tonnes/hr]	1,342	1,625	1,733
LCOD [\$/tCO ₂ captured]			
• Modular	\$259	\$261	\$262
• Scaled	\$173	\$171	\$172
NPP & S-DAC			
Electricity production [MW]	0	0	42
CO ₂ capture [tonnes/hr]	118	155	165
LCOD [\$/tCO ₂ captured]	\$679	\$648	\$680

4.3.2.2 Comparison of LCOD with Previous NETL and Literature Estimates

The LCODs obtained for the NPP&DAC systems are compared in Figure 4-2 with those obtained by NETL in previous studies on non-nuclear systems. For the L-DAC system, the LCOD shown assumes a “modular” cost (scaling factor = 1.0) for more meaningful comparison with previous NETL results.

This study shows that for both the L-DAC and S-DAC systems, an NPP adds a small economic benefit. The main differences are that the NPP&DAC system has a higher CAPEX and lower fuel costs than NGCC&DAC: the energy cost (natural gas for NGCC to supply power to L-DAC and power and heat to S-DAC) is reduced with the use of an NPP onsite, and is partly compensated for by added CAPEX and O&M costs. Overall, the different NPP types lead to reduction of LCOD by 5–7% for L-DAC, and by 8–13% for S-DAC. The reduced LCOD of the NPP&DAC system is explained by the decarbonized heat (S-DAC) and electricity (S-DAC and L-DAC) the NPP provides that doesn’t require compensation through the design of a larger DAC system (with increased energy requirement and system size affecting both operation and capital costs). The L-DAC and S-DAC analyzed by NETL [13], [14] were oversized by roughly 28% and 14%, respectively, to compensate for fossil fuel-based emissions. The L-DAC estimates

do not account for scaling factor for this comparison (“L-DAC(M)” stands for “modular” costs), since this scaling factor is a direct consequence of the larger size considered for the NPP. The L-DAC cost scaling factor does not directly result in the specific use of NPP for energy production but from the larger sized considered in this study to match output of the 1-GWth NPP selected for this study.

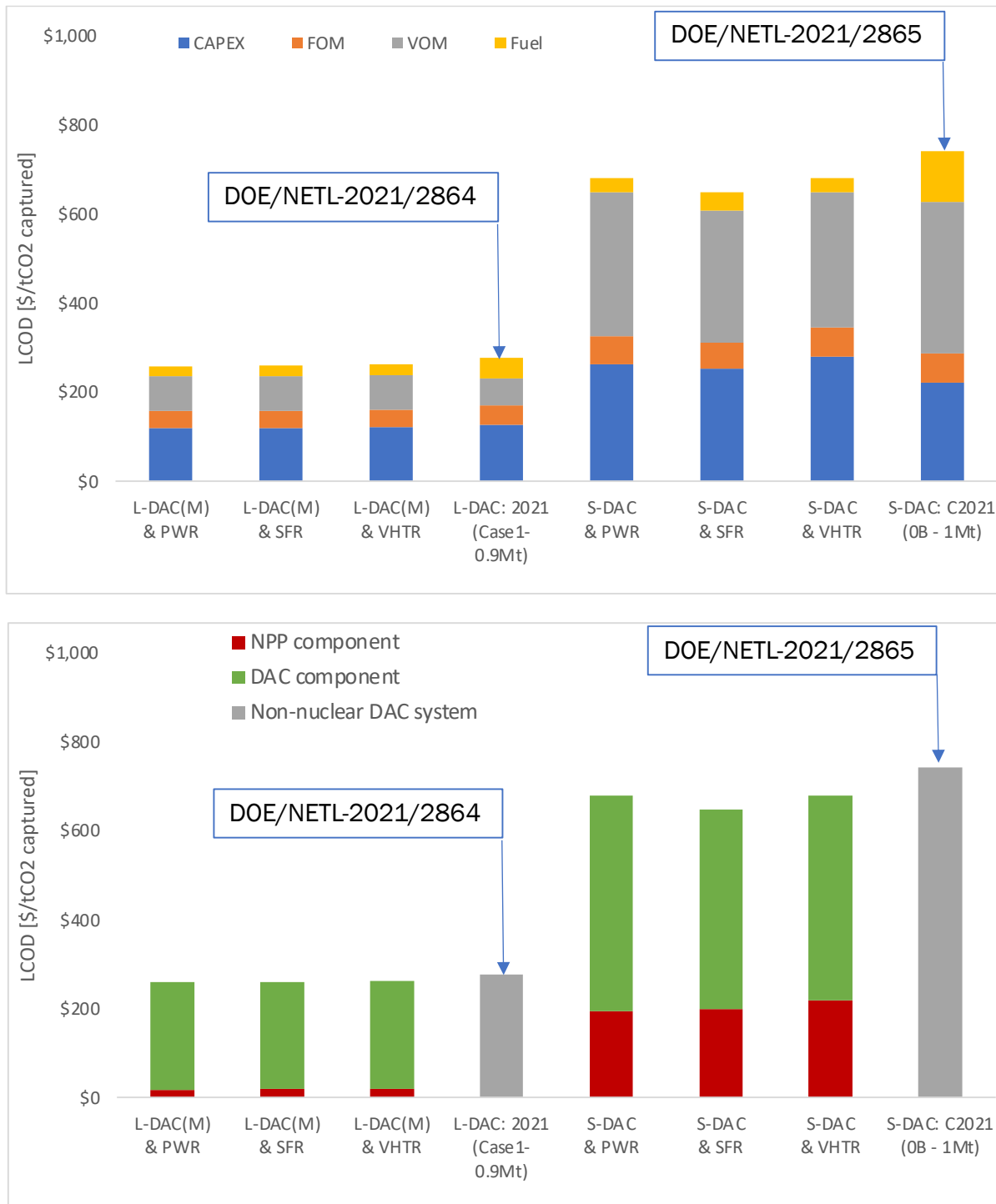


Figure 4-2. Comparison of LCOD for NPP&DAC systems with previously assessed DAC systems from NETL [13], [14]: breakdown by cost type (above) and by NPP&DAC component (below).

Similar cost ranges were obtained by McQueen et al., who conducted a techno-economic analysis of coupled NPP&DAC systems based on the cost and performance information for different types of NPP and DAC [9] [10]. One of their studies used PWR and SMR costs based on those provided by EIA [81] and L-DAC costs from Carbon Engineering [82], and concluded that the resulting capture cost ranged from \$370 to \$620/tCO₂ [9]. The resulting cost of capture from these studies and the present work differs as a result of the different sources of cost assumptions and sizes of the assumed plants.

4.3.2.3 Market Outlook for NPP&DAC Processes

Using the estimates of cost and performance of NPP&DAC systems completed in previous sections, this section discusses the ability of this technology to compete in different CO₂ markets that are described in Section B-2.

The range of LCOD of NPP&DAC systems is displayed in Figure 4-3 and compared with different identified CO₂ incentives. Four combinations of potential CO₂ revenues are shown in Figure 4-3:

1. \$170/tCO₂: Capture for Enhanced Oil Recovery (EOR) is expected to benefit from \$130/tCO₂ of revenue from the 45Q tax credit in the IRA, plus \$40/tCO₂, which is the average market price for CO₂ used in EOR.
2. \$180/tCO₂: Capture for geologic sequestration would, at a minimum, be eligible for this 45Q tax credit in the IRA.
3. \$530/tCO₂: Capture for industrial applications may access smaller industrial markets, such as the food industry, that rely on high-purity CO₂ and where prices of \$400/tCO₂ were observed. This revenue can be combined with the \$130/tCO₂ from the 45Q tax credit in the IRA, line (1).
4. \$979/tCO₂: Capture for geologic sequestration may receive funding from a voluntary offset market, where prices of up to \$775/tCO₂ were observed. This revenue would add to the \$180/tCO₂ from the 45Q tax credit in the IRA, line (2).

The range bars account for the use of different NPP types, the L-DAC scaling factors, and estimates for CO₂ transportation and storage by applying an add-on to the NPP&DAC LCOD of 0/10/20 \$/tCO₂ for the min/avg/max values. The following revenue amounts are shown in Figure 4-3:

- The use of DAC for CO₂ capture and industrial applications should be eligible for revenues ranging from \$170 to 530/tCO₂, which is the range from (1) to (3). A utility would, at minimum, be able to receive \$130/tCO₂ from the 45Q tax credit in the IRA. Some CO₂ commodity markets have shown prices of up to \$400/tCO₂ (3).
- The use of DAC for CO₂ capture and geological sequestration should be eligible for revenues ranging from \$180 to 979/tCO₂, which is the range from (2) to (4). A utility would, at minimum, be able to benefit from \$180/tCO₂ of credit from the 45Q tax credit in the IRA (2). For the L-DAC system, additional tax credits from 45Q would likely be available for the extra CO₂ being captured for compensating emissions from natural gas combustion in the calciner. For 1 Mt/yr of “net” CO₂ captured and sequestered by L-DAC (which would be eligible under 45Q for \$180/tCO₂), the “gross” CO₂ captured and sequestered is 1.28 Mt/yr: the extra 0.28 Mt/yr captured is technically from fossil fuel combustion and could be eligible for the CO₂ capture 45Q credit (\$85/tCO₂). This would increase the 45Q tax credits available for an L-DAC system¹² to ~\$204/tCO₂ captured from air (not shown in Figure 4-3). Then, the utility may be able to access the voluntary offset market (4). Other credits from State incentives may also be applicable.

¹² Calculated: \$204/tCO₂ = 0.28 * \$85 + 1.0 * \$180

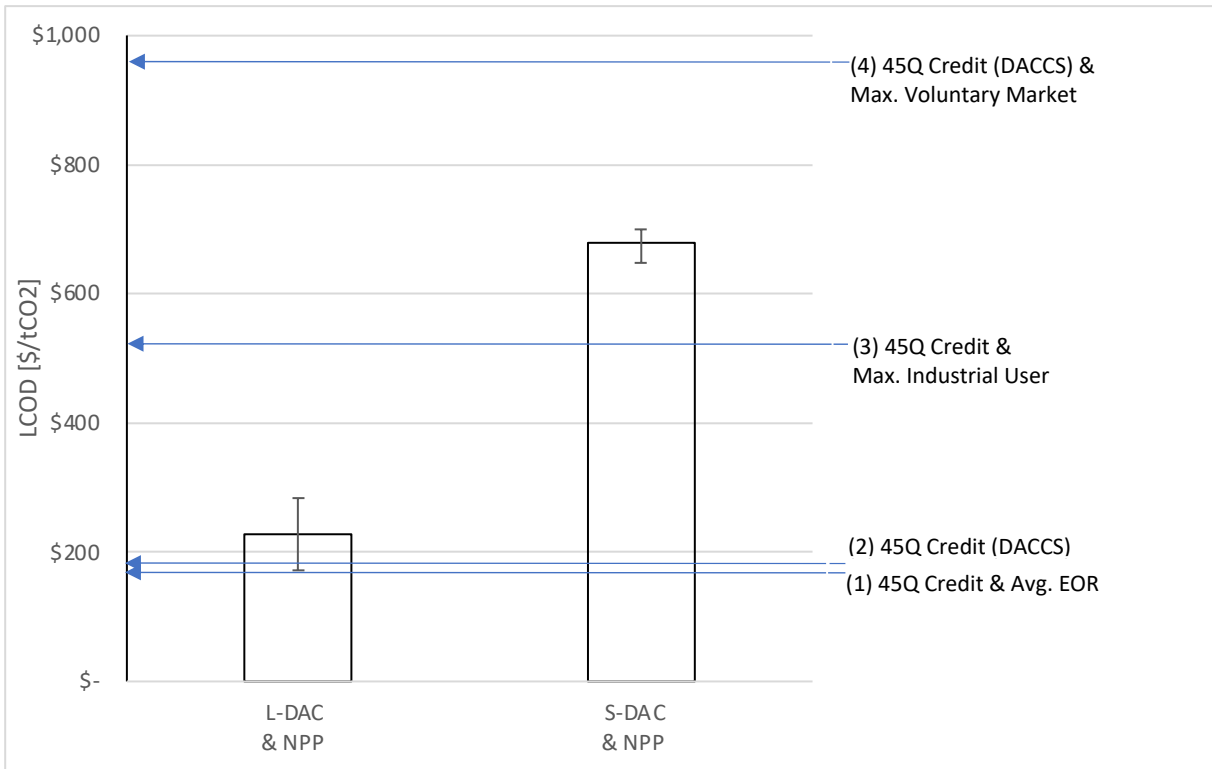


Figure 4-3. Comparison of LCOD for NPP&DAC systems with various scenarios of CO₂ market prices and federal incentives.

To summarize, current incentives and observed market prices would be compatible with deployment of the NPP&DAC process. The NPP&L-DAC process would be compatible with more markets because it has a smaller LCOD than the NPP&S-DAC process. However, the large investment needed for NPP&DAC processes would require long-term certainty of sufficient market size and price certainty, and stable incentives. Once again, the competitiveness of NPP&DAC systems when compared to other systems (such as VRE&DAC) are outside the scope of this study.

4.3.2.4 Economic Incentives for Flexible Operation of NPP&DAC Systems

As the energy grid moves toward decarbonization, the electricity market prices in deregulated markets tend to fluctuate significantly owing to increased VRE penetration, which leads to near-zero or negative wholesale prices during periods of low demand and high VRE production, and high wholesale prices during periods of high demand and low VRE production. Enabling NPPs to ramp up or down was found to lead to slightly higher revenues [83]. Adding the possibility of ramping down electricity generation during periods of low electricity prices to support other services such as CO₂ capture, or ramping down CO₂ capture during periods of high electricity prices, would maximize the revenues of the NPP&DAC system.

Assessing the technical capability of NPP and DAC systems to ramp up or down is beyond the scope of this report. At a high, qualitative level, S-DAC systems should be more amenable to flexible operation than L-DAC systems. S-DAC systems have a higher degree of utilization of modular systems, which would allow for the turndown or shutoff of individual DAC units to allow for system load reduction. L-DAC has several large, high-temperature process components that would require additional considerations for turndown. The focus instead is on making the economic case for such capability. The proposed approach estimates the average revenues of the NPP&DAC system coming from CO₂, and

assesses the equivalent electricity price that would be required to make electricity revenues more worthwhile than CO₂ revenues.

The revenue and equivalent electricity price were calculated for ranges of electricity and CO₂ market prices and federal incentives. The revenue from different electricity market prices was evaluated for the NPP-only case, because the extra electricity available to sell in the market is zero for PWR and SFR and small for VHTR, once associated with DAC processes. Resulting revenues and equivalent electricity price are summarized in Table 4-7. It is noted that the “equivalent” electricity price refers to an electricity price that would lead to a similar revenue to CO₂ in the NPP&DAC process. Thus, the electricity market price should be equal to or higher than the equivalent electricity price to compensate the revenue loss from the ramping down of DAC systems. This approach is approximate, as it doesn’t account for reduced expenses attributable to DAC (VOM and fuel cost) when it is not operating and the potential added cost of ramping it, but it is still useful to provide the order-of-magnitude electricity price that would make electricity production more competitive than DAC operation.

Table 4-7. Revenue estimates for different NPP (1-GWth)&DAC systems and operation modes.

Operation Mode	Electricity incentive + market price [\$ /MWh]	CO ₂ incentive + market price [\$ /tCO ₂]	PWR	SFR	VHTR
NPP only	Price range		Revenues [k\$/hr]		
	33.7	-	10.9	13.1	14.0
	80*	-	25.8	31.0	33.3
NPP & L-DAC	Price range		Revenues [k\$/hr]		
	-	204	274	332	354
	-	300*	403	488	520
	Price range		Equivalent Electricity Price [\$ /MWh]		
	-	204	850	854	850
NPP & S-DAC	-	300*	1,250	1,256	1,250
	Price range		Revenues [k\$/hr]		
	33.7**	180	21.3	28.0	31.2
	33.7	700*	82.8	108.8	117.3
	Price range		Equivalent Electricity Price [\$ /MWh]		
	33.7	180***	66	72	75
	33.7	700*	257	280	282

* Selected electricity or CO₂ price that would make the process competitive based on LCOE/LCOD estimates described in Section 4.3.2.1.

** For PWRs and SFRs, there are no electricity sales in either the S-DAC or L-DAC system, while about 10% of electricity from VHTRs is available for sale in the S-DAC system. An increase in electricity market price from \$33.7/MWh to \$80/MWh only adds 2 k\$/hr to the revenue of VHTR/S-DAC, which is quite small. Thus, the impact of electricity price on the NPP&DAC system was not evaluated.

*** The CO₂ incentives would not be sufficient to support deployment of these technologies, so these results should not be considered.

From this study, one can estimate the following:

- For NPP&L-DAC, the revenues are higher than for NPP&S-DAC: i.e., 274–354 k\$/hr for the CO₂ price of \$204/tCO₂ and 403–520 k\$/hr for the CO₂ price of \$300/tCO₂. As a result, the equivalent electricity price also increases. For instance, the CO₂ price of \$300/tCO₂ is equivalent to the electricity price of ~\$1250/MWh. The results indicate that the ramping down of L-DAC is not attractive unless the electricity market price is very high.
- For NPP&S-DAC, the revenue is 21–31 k\$/hr for the CO₂ price of \$180/tCO₂ and it increases to 83–117 k\$/hr for the CO₂ price of \$700/tCO₂. The CO₂ price of \$700/tCO₂ is equivalent to an electricity price of \$257–282/MWh. In other words, in order to compensate for the revenue loss from the complete ramping down of the DAC system, the electricity market price would have to be in the range of \$257–282/MWh. A CO₂ price of \$180/t based on only the 45Q tax credit would not be sufficient to justify deployment of the system because of smaller equivalent electricity prices.

In the Electric Reliability Council of Texas (ERCOT) region in 2022, where the average wholesale electricity price [84] was \$62/MWh, the bus average price was above \$1,255/MWh for 0.3% of the year, it was above \$850/MWh for about 0.4% of the year, and it was above \$270/MWh for 1.5% of the year. Consequently, it is unlikely that an NPP&DAC (in particular, L-DAC) system would be incentivized to ramp down CO₂ capture to ramp up electricity production for more than a few days per year. This is because the revenues expected from CO₂ sequestration are required to be high to justify deployment and continuous operation of the very expensive DAC technologies. More in-depth market modeling would help further refine these estimates.

5. CONCLUSIONS

The U.S. administration has set ambitious decarbonization goals for the U.S. economy that, alongside recent legislation, are promoting the development and deployment of low-carbon energy production and of carbon capture technologies. The Systems Analysis and Integration (SA&I) campaign of the Office of Nuclear Fuel Cycle and Supply Chain, Department of Energy's Office of Nuclear Energy, has evaluated the potential for nuclear energy to power various Negative Emission Technologies (NETs). NETs are part of the emerging market for carbon dioxide removal services to potentially mitigate and reverse some of the effects of climate change. In this report, the carbon reduction performance and market feasibility of nuclear energy coupled with NET systems were assessed.

5.1 Results Overview

Among the various NETs that are actively being developed, several were found to potentially benefit from coupling with a nuclear power plant (NPP) via (1) large amounts of decarbonized and constant-output electricity; (2) free waste heat or cheap low-temperature heat; or (3) high-temperature heat from Sodium-cooled Fast Reactors (SFRs) or Very High Temperature Reactors (VHTRs). The most promising nuclear NETs included Direct Air Capture (DAC), Indirect Seawater Capture (ISC), Engineered Enhanced Weathering (EEW), Pyrogenic application to Carbon Capture and Storage (PyCCS), and gasification. NPPs would likely pair well with DAC, EEW, and ISC systems by providing both electricity and heat. For PyCCS and gasification, an NPP can provide both heat and electricity to increase the carbon capture efficiency of these systems by saving bio-gas that would otherwise be used to fuel these systems. Although BioEnergy with Carbon Capture and Storage (BECCS) technology is prominent in the literature, it is expected that an NPP would not provide additional value to the system, since it produces its own decarbonized heat and electricity.

The quantity and quality of the heat available from three NPP types—Pressurized Water Reactors (PWRs), SFRs, and VHTRs—were optimized for coupling with different DAC systems. These three NPP types were assessed using balance-of-plant modeling of industry-representative designs. The NPP&S-DAC (solid sorbent DAC) system required optimization of the quantity of ≈ 150 °C steam extracted from the PWR and SFR to maximize heat and electricity utilization by the DAC system. Free waste heat at 125 °C was utilized from the VHTR helium cycle, which resulted in extra electricity produced by the VHTR&S-DAC system. For the NPP&L-DAC (liquid solvent DAC) system, only electricity from the NPP was utilized by the L-DAC, since high-temperature heat (≈ 900 °C) could not be provided by the NPP designs considered. Heat for the L-DAC system was instead generated from oxy-combustion of natural gas.

A detailed techno-economic analysis of coupled nuclear DAC processes was completed for both L-DAC and S-DAC technologies. The L-DAC process enables much larger atmospheric CO₂ capture than the S-DAC process when both are sized with a 1-GWth reactor, despite requiring >2 GWth of supplemental natural gas combustion and flue gas CO₂ capture. A 1-GWth NPP coupled with L-DAC and S-DAC was found to be able to capture 12–15 Mt CO₂/yr and 1.0–1.5 Mt CO₂/yr, respectively. Higher CO₂ capture performance was obtained from NPPs providing higher-temperature heat together with higher thermal efficiency.

The levelized cost of carbon capture from DAC (LCOD) was much lower for nuclear L-DAC systems compared to nuclear S-DAC systems. LCOD had a range of \$170–260/tCO₂ for NPP&L-DAC systems, and a range of \$650–680/tCO₂ for NPP&S-DAC systems. The LCOD did not vary significantly between different NPP types because more efficient reactors also tended to have higher costs, leading to similar LCOD. For both DAC systems, the NPP does add an economic benefit when compared to previous NETL studies of non-nuclear DAC systems, leading to a reduction of LCOD by 5–7% for L-DAC and by 8–13% for S-DAC. Using clean, carbon-free electricity and heat from a paired nuclear reactor reduces the gross amount of CO₂ that needs to be captured by the DAC system by avoiding the

need to compensate for fossil fuel-based CO₂ emissions that are otherwise associated with the supply of DAC energy requirements. This, in turn, reduces the DAC system size and energy requirement of the overall system. Consequently, the NPP&DAC has higher CAPEX and lower fuel costs than non-nuclear DAC since external fuel feeds (natural gas for heat and electricity) are reduced but partly compensated for by the capital and operating costs of the NPP.

The NPP&L-DAC process is much more likely to be profitable with today's incentives and market prices, owing to smaller LCOD than the NPP&S-DAC process. When DAC systems were sized to maximize their use of NPP electricity and heat, the estimated DAC capital and operating costs were comparable to or exceeded those of the NPP. Thus, the economic viability of these systems will require high revenues from CO₂ capture, which could currently come from federal (tax credits under Section 45Q) or state incentives, voluntary emission offset markets, or commodity markets for CO₂ or byproducts. However, some of these industrial applications, such as synfuel generation or enhanced oil recovery, may not lead to net negative emissions since some CO₂ would eventually be directly or indirectly released into the atmosphere. Ultimately, the large investment needed for the NPP&DAC process would require long-term certainty of sufficient market size, prices, and incentives.

Enabling NPPs to ramp DAC operation up or down based on the electricity and CO₂ prices is not expected to significantly increase combined NPP&DAC system revenues. This is because the revenues from CO₂ sequestration are required to be very high to justify deployment and continuous operation of the very expensive DAC technologies. For example, the electricity market wholesale prices would need to reach \$1,250/MWh (a price observed during less than 0.3% of the year in the Texas ERCOT market) to incentivize the NPP&L-DAC system to produce electricity instead of capturing CO₂, assuming revenues of \$300/tCO₂.

The analysis of NPP coupling to EEW and PyCCS technologies was initiated in this work, and they showed comparable technical potential to the DAC systems for CO₂ capture and storage. Based on the energy requirement for the EEW process, a 1-GWth VHTR would theoretically be able to capture ≈ 7 Mt CO₂/year while still being able to produce 377 MW_e of electricity for sale. However, only a small fraction of the NPP energy would be used for EEW because of the large quantities of land, water, and rock needed for CO₂ capture, making it very difficult to scale up this process to use the full output from a 1-GWth nuclear reactor. For the NPP&PyCCS process, a 1-GWth SFR would theoretically provide enough energy for pyrolysis of 16 Mt of biomass/year, and CO₂ capture and storage of ≈ 22 Mt CO₂/yr (including storage of biochar together with most of the produced bio-oil and bio-gas, although this storage might be economically suboptimal for a plant owner). Based on the initial analysis performed in this report, biomass- and water-based NETs are potentially compatible with NPPs, but it will require further work to quantify the performance of these systems. These NETs might use less energy than DAC, since they process carbon that is more concentrated than in the atmosphere, increasing the CO₂ stored per NPP, and in some designs they can create valuable byproducts like hydrogen and bio-oil.

5.2 Key Observations

The analysis completed in this report shows that a 1-GWth NPP can provide enough energy to support DAC technologies that would remove 1–15 Mt CO₂/year. While this represents a large capture capability from a single NPP, it is important for the reader to keep in mind the following:

- The Intergovernmental Panel on Climate Change (IPCC) [1] targets removal of 400–5,200 Mt CO₂/year throughout the 21st century to limit global warming to 2 °C, which would require deployment of NPPs generating 27 to 5,200 GWth, depending on the type of NET considered. For perspective, the current global NPP fleet generates ≈ 390 GW_e, representing $\approx 1,200$ GWth.
- When connected to an electric grid, a 1-GWth PWR would avoid emissions of about 1 Mt CO₂/yr if it prevents production from an equivalent Natural Gas Combined Cycle (NGCC) plant. Since any additional fossil CO₂ would eventually need to be removed in addition to all of the CO₂ already

emitted, the priority should be on deploying NPPs for decarbonizing the grid prior to deploying them for removing CO₂ from the atmosphere. Grid-connected NPPs currently provide both electricity and decarbonization (via emissions avoidance), while nuclear NET is more expensive because of the added capital and operating costs of the DAC system (and only provides a decarbonization service).

- A high rate of CO₂ capture and storage is obtained with PyCCS when one assumes that the bio-oil and bio-gas produced are being sequestered. However, industrial uses of such commodities could bring significant revenues to the plant when processed as bio-fuels (the same is true for CO applied to synfuel production), although these products would eventually release CO₂ back to the atmosphere, reducing the negative emission performance of the system. There is an interesting tradeoff, which needs analyzing, between 1) maximizing CO₂ removal to compensate for fossil fuel CO₂ emissions in hard-to-abate sectors and 2) reducing negative emission performance but enabling decarbonization of such hard-to-abate sectors through the production of (ideally) carbon-neutral synfuel and bio-oil.

5.3 Gaps and Future Work

The analysis completed in this report provided a review of NETs, their compatibility with NPPs, and a detailed analysis of NPP&DAC systems. In this process, several questions were uncovered, and follow-up analyses are recommended for further investigation:

- Additional NET processes, such as PyCCS, gasification, ISC, and EEW, should be considered for detailed analyses. Other DAC systems such as electro-swing absorption and reactive membrane-based DAC could also be considered. Finally, the use of high-temperature heat from NPP in L-DAC systems should be revisited. The flexibility of NET systems, including DAC, could be further investigated.
- Beyond negative emissions, this work could be extended to CO₂ capture from flue gas to reduce emissions from various industrial processes (such as coal gasification for synfuel production [85]) or fossil-fuel power plants. Those may use different CO₂ capture technologies that could be considered as well for coupling with NPP.
- Siting analysis of the NPP&DAC processes could be performed to assess locations that would be suitable for both NPPs and NET processes, with CO₂ geologic sequestration potential, water availability, biomass resource, access to markets (with CO₂ customers, or areas where policies are available), etc.
- Detailed life-cycle and market analyses could be completed on the nuclear NET process to assess the above-described economic and environmental tradeoffs: production of electricity vs. negative emissions, and sequestration of CO₂ and bio-fuel vs. industrial use leading to CO₂ release to the atmosphere.
- Detailed market analyses could be completed to make a clearer case for the economic viability of nuclear NET processes. One could use an agent-based tool like ABCE for decision-making analysis of investments in such NET technology, based on market size and evolving CO₂ price, but also based on competing VRE and natural-gas-powered NETs.

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Appendix A

Preliminary Study of Techno-Economic Feasibility of Pairing Nuclear Energy with EEW and PyCCS Negative Emission Technologies

This section extends the techno-economic analysis performed on NPPs with DAC systems to other NETs for which coupling with nuclear energy is at a more prospective stage. For EEW and PyCCS, an attempt is made to estimate the amount of CO₂ that could be removed with different nuclear NETs, together with the revenues attributable to the NET (in terms of CO₂ emissions and other commodities). These are preliminary estimates, mostly based on the use of literature data, made to assess the CO₂ capture scale and economic viability of these NETs.

In this section, orders of magnitude are provided without attempting a detailed and high-fidelity system design and performance analysis, which would be recommended as a follow-up step on the most promising technologies.

A-1. NPP & EEW

The EEW technology considered in this report is at an early development stage, with only laboratory demonstration. Consequently, the capital and operation costs are not available, especially for a scaled-up concept that would require a large land area and water reservoir. Consequently, the economic assessment will focus on the energy costs, which are expected to be significant for EEW.

The following (mostly theoretical) performance evaluations are derived from EEW design E from [47]. An energy consumption of 1.2 to 2 MJ/kg CO₂ captured was obtained: this represents 1.75 MJ/kg CO₂ of electrical energy (for S-DAC), representing ~4.4 MJ of thermal energy according to [47] and 0.31 MJ/kg CO₂ of electric energy for pumping and supplying material particles. This estimate assumes that lower CO₂ enrichment is needed for this process, so one could use much cheaper technologies than those considered in Section 4. For conservativeness, the assumed loss of CO₂ owing to degassing from water in this analysis reaches 50%, which is consistent with (but on the higher end of) degassing estimates from [47].

For this analysis, the VHTR concept discussed in Section 3.1 with operating mode #3 is selected, i.e., electricity production at a thermal cycle efficiency of 45% and use of waste heat at 125 °C for S-DAC operation. This approach makes sense, as EEW uses energy to drive an S-DAC process (which was found compatible with a similar reactor/scenario) and electricity.

CO₂ Removal Efficiency Expected

Considering the VHTR concept with operating mode #3, a 1-GW thermal reactor would be able to generate 446 MWe (of which 30 MWe are assumed to be used for the house-load of the NPP) and 554 MWth. Based on the energy requirements for the EEW process, such a reactor would **theoretically** be able to capture ~456 tCO₂/hr, while still being able to sell 377 MWe of electricity if using waste heat for S-DAC operation¹³.

This estimate assumes that the waste heat available from VHTR will be usable to operate the S-DAC system. In the alternative scenario where only electricity could be used for the DAC process, the VHTR would be able to capture ~365 tCO₂/hr while using all the generated electricity (no electricity sent to the grid, and no waste heat utilized in this process). Both estimates show boundary conditions for the efficiency of such a system.

Performance of such an EEW concept needs to be verified at the industrial stage. The design of EEW technology needs optimizing, and its performance will depend on the type of rocks, the type of seawater, the atmospheric CO₂ concentration, the DAC technology applied, the degassing rate, etc.

¹³ Alternatively, it would be able to capture ~391 tCO₂/hr while using all the reactor-generated electricity (none of the waste heat).

Revenues Expected

At 33.7\$/MWh, such a VHTR would generate \$14,000/hr. With CO₂ capture, the electricity production would drop to ~377 MWe, leading to ~\$12,700/hr of electricity revenues. Based on discussion in Section B-2, it is not clear what incentives for CO₂ storage would be available to EEW. Using \$35/ton CO₂ capture as an example, for a capture rate of 456 tCO₂/hr, the revenues would increase to \$28,700/hr, more than doubling the NPP revenues. However, such potentially increased revenues currently don't include added capital and operating costs, which should be significant in view of the scale-up challenges discussed next.

Scale-up Challenges

It should be noted that capturing ~456 tCO₂/hr from a 1-GWth reactor would involve a significant amount of rock transportation, a large area, and water flow availability.

First, transportation of large amounts of crushed rock would be required, as 1 kg of calcite rock when dissolved will remove less than 0.44 kg of CO₂ (not accounting for long-term degassing). Consequently, around 16 Mt/year of rock would be required to reach a capture rate of ~456 tCO₂/hr, which represents ~2 freight trains every day. This amount remains, however, less than 3% of the U.S. artificial silicate production (coming from various industrial wastes), which is ~0.5 Gt/year [46].

The relatively slow kinetics of the chemical reaction would require an estimated 1300 hectares of land. The water consumption rate would be ~355 m³/s (this water would be released to the environment after being enriched with bicarbonate ions).

Summary

Based on the above discussion and estimates, NPP could provide the heat and electricity needed for the operation of EEW. However, it is likely that only a small fraction of NPP energy would be used for EEW because of the large quantity of land, water and rock needed for CO₂ capture by EEW, making it very difficult to scale up such a process to use the full output from a 1-GWth nuclear reactor. Further analysis of this concept would require specific capital and operating cost estimates for the EEW system.

A-2. NPP & PyCCS

Despite wider availability of cost estimates for operating large-scale pyrolysis plants, this analysis focuses on early-stage energy estimates that can be provided by NPPs and used to support the PyCCS process. For this analysis, an SFR reactor in operating mode #1 (only used for heat generation) is used as the example case. Higher temperatures (with a VHTR) would be appropriate as well, together with some production of electricity for parts of the process (this scenario won't be considered here, since the electrical output required could not be readily obtained from the literature).

CO₂ Removal Efficiency Expected

The amount of energy needed is not widely reported, but Ref. [86] mentions requiring 1.77 MJ/kg to heat the dried biomass sample (waste from the paper industry) to 500 °C; this figure neglects the energy needed for drying the biomass and for other pre- and post-pyrolysis processes. Biomass is ~50% C [87], which would represent 0.5 kg of pure carbon or 1.8 kg of CO₂ per 1 kg of biomass. Other studies consider pyrolysis to be energy-neutral [88] (likely because of the combustion of some generated bio-gas in these processes).

Based on these estimates, a 1-GWth SFR reactor in Operating Mode #1, such that the generated heat is only used for pyrolysis, would be able to heat up 565 kg/s (or 16 Mton/year) of biomass. Assuming a CO₂ sequestration of 75% for PyCCS (only bio-char and bio-oil would be sequestered), this would represent 22 Mton CO₂ sequestered per year, or 2,500 tCO₂/hr.

This CO₂ removal efficiency is higher than that of NPP&DAC, which can be explained by the fact that carbon is much more concentrated in biomass than in the atmosphere, and the pyrolysis process doesn't require a very large amount of energy to be triggered (when compared to enriching air with CO₂). This process is less energy-intensive, but requires access to biomass, which may limit its deployment potential.

Under these assumptions (SFR, scenario #1), such a nuclear reactor would not be used for electricity generation; however, this process would result in production of ~4 Mton/yr of bio-gas, ~4t Mton/yr of biochar, and ~8 Mton/year of biofuel (using the yield from hardwood pyrolysis under low-temperature conditions [89]).

Revenues Expected

Market values for bio-oil, bio-gas, and bio-char proposed in [90] are 0.4 \$/kg, 0.056 \$/kg and 0.2 \$/kg, respectively. At such prices, the hourly revenues from a 1-GWth reactor could be \$481k, calculated from sales of bio-fuel (\$366k), biochar (\$91k), and bio-gas (\$26k) minus ~\$2k to purchase electricity for house-load operation. This figure should be compared to revenues of \$13k/hr obtained from a reactor of this size from conventional sales of electricity. Only revenues from biochar and some bio-gas (after separating non-carbon gas such as hydrogen) should be counted in a system targeting maximized negative emissions.

However, those revenues need to be translated into net benefits after accounting for added capital and operating costs. Some plant cost data were found in [90] for a 20-ton/hr oil palm waste pyrolysis plant showing CAPEX of \$75–80 M and OPEX of \$17–20 M/yr. The feedstock price is 41% of operating cost, and the energy price is not provided, likely because bio-gas is used as the energy source. Scaling those costs up to the size of the NPP considered won't be attempted in this preliminary study.

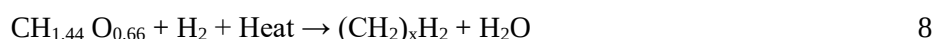
The 1-GWth NPP provides enough heat for pyrolysis of ~48,000 t of biomass per day, which is the order of magnitude of a large biorefinery (200,000 barrel/day). According to [88], such a large quantity of biomass is likely not appropriate for economical transportation, and intermediate biomass products may be required for transportation. Those intermediate products (pellets of dense biomass, bio-gas, bio-oil, etc.) would be generated in Regional Biomass Processing Depots and processed from pyrolysis or other processes (such as anaerobic digesters), which could potentially be fueled by small NPPs [88].

Processes Proposed to Increase Value of Biomass Products

The bio-oil generated through pyrolysis has drawbacks: it is reactive, unstable, corrosive, and low in specific energy [88]. Consequently, it requires treatment before transportation and usage through:

- Electrocatalysis (hydrogenation and deoxygenation) to stabilize it chemically, which requires electricity. This can be done on a smaller scale at a biomass upgrading depot.
- Hydroprocessing to improve specific energy, which requires electricity, heat, and hydrogen, and should be managed in large, centralized refineries.

According to [88], at least 3,000 million tons/yr of biomass is available in the U.S., enough to produce 30MM bpd of liquid hydrocarbon (the current consumption is 18MM bpd) [91]. The proposed approach consists of using an NPP for producing both heat and hydrogen to convert biomass (CH_{1.44}O_{0.66}) into a hydrocarbon ((CH₂)_xH₂) based on Eq. 8. This process enables more efficient conversion and access to more widely available biomass feed [92].



Such a process can be achieved through the re-use of existing refinery infrastructure via three modifications [91]:

- A front-end process (such as pyrolysis and gasification of biochar) is needed to transform biomass into bio-fuel;

- The bio-refinery requires heat and electricity that may come from a nuclear reactor such as a VHTR; and
- The biorefinery requires hydrogen production, which may come from one of the following:
 - Steam methane reforming associated with carbon capture and storage. As with the BECCS process discussed in Section 2.2.1.3, NPPs are not expected to play a significant role in this process.
 - High-temperature hydrolysis using an NPP to produce both heat and electricity.

Significant work is in progress on design and modeling of such systems [88]. One of the bio-refinery systems proposed in [88] uses 1 Bt of raw biomass to produce 0.125 Bt of biochar and 0.323 Bt of usable fuel. This represents ~ 0.23 Bt CO_2 stored as biochar¹⁴ (produced in the local depots) and returned to the soil to re-enrich its nutrients: it is still net negative (if energy is coming from an NPP), but much less so than if it were focused on negative emissions, since carbon in other by-products (bio-gas and bio-oil) will ultimately be released as CO_2 through combustion. Alternatively, biochar can be used as feedstock for gasification processes to produce additional hydrocarbon fuels, making the overall process carbon-neutral unless the CO_2 produced in gasification and the back-end combustion process is captured and sequestered. This process would require ~ 10 EJ of electricity (this study did not account for processed heat that may be available from the NPP for part of the process), which represents production of 317 GWe for 1 year. The use of decarbonized electricity is critical for significantly reducing the life-cycle emissions of bio-fuel production.

The concept of the bio-refinery leads to lower negative emissions performance when compared to processes that would sequester a larger “C” fraction from the biomass. However, in addition to its CO_2 reduction impact, widespread bio-refinery deployment would likely still play a large role in compensating for hard-to-abate sectors by producing carbon-neutral bio-fuel for transportation (aviation, marine, trucks, etc.).

Summary

Based on the discussion above, biomass pyrolysis could help support significant negative emissions through CO_2 storage as biochar and potentially biofuels. High-temperature nuclear reactor systems could support such processes by providing high-temperature heat to fuel the endothermic pyrolysis reaction. It is not clear how much benefit would be derived from using nuclear heat versus bio-gas heat, which has a relatively low market value but would lead to slightly reduced negative emission performance when compared to a system where carbon components of bio-gas are sequestered. Furthermore, nuclear energy can also be used in follow-up stages of the bio-oil refinery, as discussed in [88].

¹⁴ Assuming $\text{C}/\text{biomass} = 0.5$ and $\text{CO}_2/\text{C} = 3.66$

Appendix B

Market Description of Nuclear NET-Generated Commodities

The main purpose of this appendix is to discuss markets for nuclear NET systems, and justify assumptions used in this report to estimate potential revenues for the NPP from electricity production or from CO₂ capture from the atmosphere. Other markets will be considered for some specific NETs such as biochar, biofuel, and hydrogen, as discussed in Section A-2.

B-1. Revenues from Electricity Markets

Electricity is the main commodity currently produced by NPPs. For simplicity, other types of electricity revenues are not considered here, such as those from capacity markets, ancillary services, and state incentives, since those are very market- or region-dependent. Federal incentives for clean electricity production should also be considered, such as the Production Tax Credit of \$15/MWh in the Inflation Reduction Act (IRA) [3].

For calculating revenues of a nuclear NET system in a competitive wholesale electricity market, it is important to differentiate between types of electricity prices, which could be relevant for siting NET at an NPP site:

- **Wholesale electricity prices:** This is what the NPP receives from the sale of electricity to the grid. The average locational marginal price in the past 5 years (2015–2019) in all U.S. regions was calculated to be \$33.7/MWh. At any given time, these prices can vary substantially across a region because of transmission congestion. A large industrial user (such as a DAC system) could connect to the bulk transmission system and purchase electricity at wholesale prices in some cases.
- **Retail electricity prices:** This is the price of the electricity that NET would need to purchase from the grid if it did not use electricity produced onsite and if it did not participate in the wholesale market. These prices differ greatly depending on the type of customer, such as individual households, cities, or industries. Previous NETL studies assumed that electricity purchased by a DAC system cost \$60/MWh [14] [13].

B-2. Revenues from CO₂

Carbon dioxide provides three major revenue streams for NETs, as described in [93], from (1) the commodity market, (2) the emissions trade market, and (3) carbon credits. It is noteworthy that these sources of revenue may sometimes be accumulated. For instance, a DAC utility could take advantage of both state and federal eligible credits, while in some cases selling CO₂ to the commodity market or storing it and receiving funding from carbon trade markets.

CO₂ Commodity Market

Although CO₂ is an unwanted pollutant in the atmosphere, it has economic value in uses such as enhanced oil recovery (EOR), air-to-fuels conversion, cement and concrete, commodity chemicals, and food and beverage production. The sale of CO₂ removed from the atmosphere to these markets is known as CO₂ utilization. A brief list of applications of captured CO₂ utilized either directly or through a conversion process is presented in Figure B-1. This market is only applicable to NETs that separate CO₂, such as DAC, BECCS, gasification, and ISC. There is a considerable ongoing research effort to expand such uses, and small amounts of early revenue for the DAC industry already come from niche utilization markets [94]. Some of these industrial applications, such as synfuel generation, may not lead to “negative emissions,” since CO₂ would be eventually released to the atmosphere.

Electro-fuels (e-fuels) are developed using renewable electricity and captured CO₂. E-fuels are developed for hard-to-abate sectors like steel and cement manufacturing and long-distance transportation like shipping and aviation [95]. An example of e-fuels is e-methanol, which is produced using green hydrogen (hydrogen derived using renewable energy) and captured CO₂. Chemical manufacturing that cannot be electrified or directly decarbonized can use e-fuels and renewable energy to produce e-chemicals. These fuels and chemicals are also called Fisher-Tropsch (FT) fuels and chemicals. The use of captured CO₂

together with hydrogen/electricity from nuclear energy for FT fuel production is described in [96] as a component of research supported by the DOE-NE Integrated Energy Systems program.

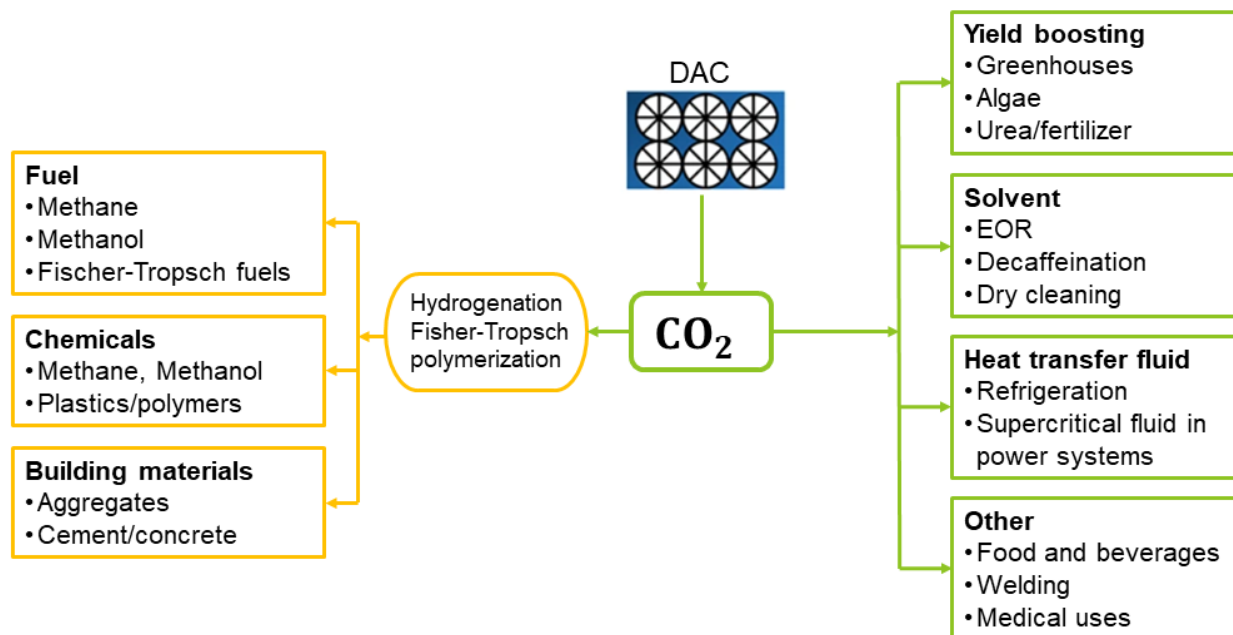


Figure B-1: Broad range of applications in which DAC CO₂ can be utilized either directly or through conversion into other products.

The global carbon dioxide commodity market was valued at \$3.2B in 2021 and is expected to grow at 8.4%/year, with the fertilizer industry being the largest user followed by the oil and gas industry [97]. The fertilizer industry needs CO₂ to produce urea, and sources all of its demand from natural gas. The oil and gas industry utilizes CO₂ for EOR: high-pressure CO₂ is injected to push oil towards the extraction drill. In the U.S., CO₂ is not a centralized traded commodity and price depends on location, source, and purity. The projected growth in utilization of captured CO₂ is expected to grow significantly beyond 2030 [98], as shown in Figure B-2.

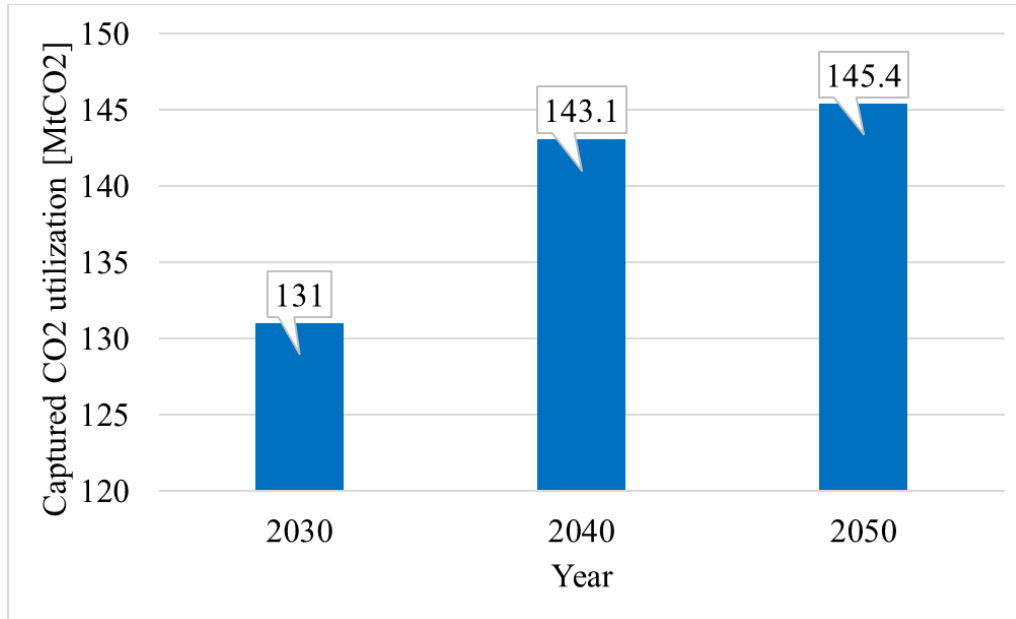


Figure B-2: Potential for captured-CO₂ utilization from all sources in the U.S.

The CO₂ commodity market will see an increase in demand from the development of sustainable materials that use carbon. These developments are expected to be commercialized after 2030. Some of the most promising fields are synthetic fuels (synfuels) and construction aggregates. Industry projects a growth in demand from 1 Gt in 2021 to 7 Gt by 2030. The aviation industry is the prime driver for developing synfuels based on captured carbon [99].

Synfuels using captured CO₂ have two benefits: First, they are effectively carbon neutral¹⁵, and second, they carry an added green value which qualifies for various tax credits and added values. Such synfuels would qualify for a Q45 tax benefit of \$130/tCO₂. This benefit will allow the aviation industry to buy synfuels at an inflated price of \$6.4/gal vs. the 2023 price of \$5/gal.

The market price of CO₂ varies depending on the season and industry supply and demand. For big industrial companies, which usually are ammonia and fertilizer producers, the price range is from \$3 to \$15 per ton. During autumn and winter, consumption by these industries reaches a peak, causing a scarcity in the market for other sectors. Markets with low volume, such as the beverage and food industry, that need high-purity CO₂ can pay as much as \$400 per ton [100]. Therefore, the supply will have to develop further to support peak demand and the expected increase in CO₂ consumption. According to [93]: “While some small applications in the US merchant market pay well over \$100/ton for high-purity CO₂, the average price for CO₂ used in EOR (by far the largest market) is approximately \$40/ton, reflecting low production costs.”

Carbon Voluntary Offset Markets

The voluntary offset markets for CO₂ are used by companies or individuals that wish to offset their carbon emissions (without government requirements or incentives). Voluntary carbon credits direct private financing to climate-action projects that would not otherwise get off the ground. These projects can have additional benefits such as biodiversity protection, pollution prevention, public-health improvement, and job creation. Prices in these markets vary widely, but have been reported at up to \$775/tCO₂ [93].

¹⁵ This assumes that all energy used to power the carbon capture system is also carbon neutral, as would be the case for nuclear NET.

There is uncertainty about the size of these markets and the offset prices. Industrial analysts at McKinsey estimate that the demand for voluntary carbon credits could increase by 15% by 2030 and could be worth as much as \$50 billion; the report also mentions that this market could increase by a factor of 100% beyond 2030 [101]. According to the Network For Greening Financial Systems (NGFS), the annual global demand for carbon credits could reach 7 to 13 Gt CO₂ by 2050 under the net-zero scenario; NGFS expects that carbon credits priced around \$160/tCO₂ would be needed by 2030 to incentivize this transition to 2050 [102].

DAC has begun to attract attention in this realm as traditional offsets, which are heavily reliant on forestry projects, face increasing concerns about their quality [103]. Also, such markets may be incompatible with some CO₂ commodity markets (such as oil extraction). For instance, JPMorgan Chase & Co recently signed contracts to sequester 800,000 tCO₂ for \$200M (or \$250/tCO₂), using technologies including DAC and PyCCS (with bio-oil underground sequestration technology from Charm Industrials) [35].

Federal and State Carbon Credits

In the U.S., federal and state carbon credit policies differ. The federal policies for CO₂ sequestration are provided by the U.S. Tax Code, Section 45Q. This Section was first released in 2008 and was updated and expanded in 2022 as part of the IRA [3, 104, 105].

- For DAC-specific processes, the tax credits are set to \$180/tCO₂ for sequestered CO₂, and \$130/tCO₂ for industrial use of CO₂ (which should include EOR).
- For CO₂ captured at power generation facilities and permanently stored in saline geologic formations, there is a tax credit of \$85/tCO₂. This credit should be applicable to BECCS. It should be noted that additional credits are available in the IRA for biomass products.
- For CO₂ captured from power generation facilities and used for EOR or other industrial purposes, there is a tax credit of \$60/tCO₂.

To qualify, projects need to start construction before 2033. This tax credit will be inflation-adjusted and will be available for a 12-year period after the equipment is placed in service. There are many other requirements that generally should apply to the types of NET projects considered in this report (for instance, at least 1,000 tCO₂/year must be captured).

Currently, there don't appear to be federal carbon credits available for EEW and PyCCS technologies where CO₂ is not captured from power generation facilities and stored in saline geologic formations.

An NPP built for electricity production for NET operation may also be eligible for the IRA Investment Tax Credit of 30% (40% in an energy community). However, this credit would likely not be compatible with applying for the 45Q carbon credit, which would likely be more interesting for an NPP developed for the prime purpose of NET operation. A possible workaround would be to have different owners for the NPP and the DAC. The Treasury Department is still working on the IRA implementation and guidance, and this potential alternative has not been explored so far.

Several U.S. states (California, Oregon, Massachusetts, Washington, etc.) have carbon pricing mechanisms that provide incentives for carbon capture and storage. California's policies include the Low Carbon Fuel Standard (LCFS) regulation [106, 107], which sets credit markets for carbon capture and sequestration. These markets are applicable to various types of CO₂ capture projects, including DAC. They do not appear to presently apply to sequestration technologies in water (EW) or biochar (PyCCS). The credit prices vary widely, from \$200/tCO₂ in 2021–2022 to ~\$70/tCO₂ more recently. The LCFS has the drawback of a relatively small market size of approximately 15 million tons of CO₂ per year (45Q is unlimited in its effective market size). A small number of megaton-scale DAC projects seeking to sell LCFS credits could drive down prices substantially, undermining their value.

