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Clean Sources of Dispatchable Electric Power

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How can Virginia achieve a 100% clean energy future by 2050?

This report explores technologies that could serve as a pathway to a carbon-neutral Commonwealth, including an overview of how these technologies function, an assessment of their viability, and recommendations for how Virginia should move forward.

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EXECUTIVE SUMMARY

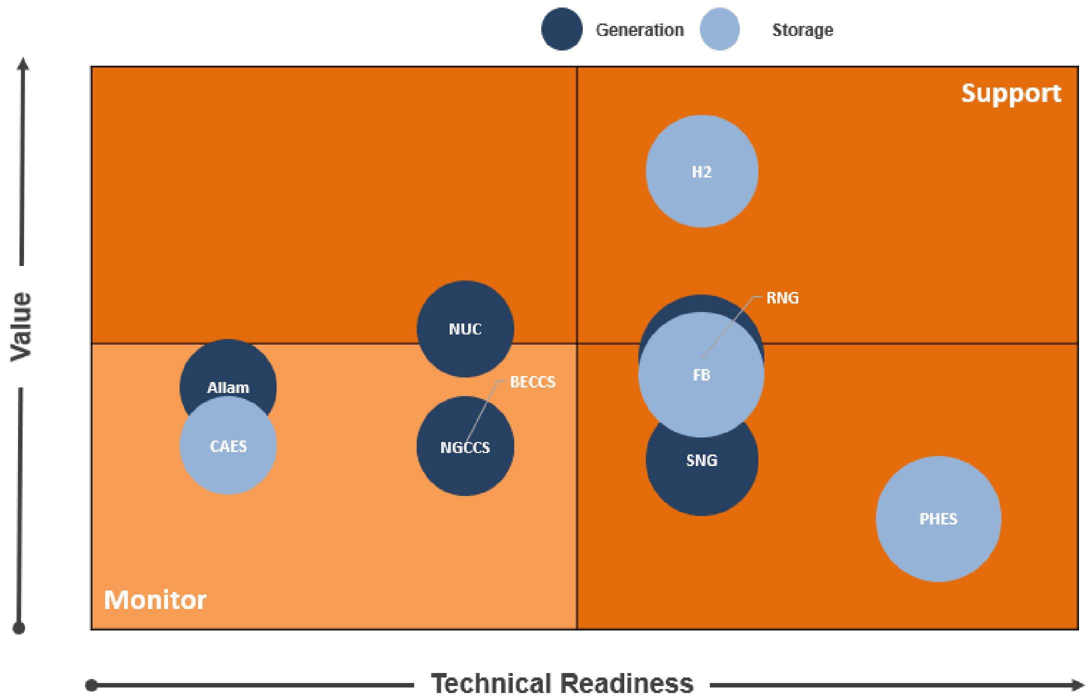
With the signing of the Virginia Clean Economy Act (VCEA), the Commonwealth of Virginia joined a chorus of state-level and utility company commitments to achieve a 100 percent carbon-free electricity system by 2050. Such commitments are a new phenomenon because they have only recently become viewed as feasible, as the costs of wind and solar power and lithium-ion energy storage technologies have fallen precipitously.

Reviews of the recent academic literature modeling pathways to a 100 percent carbon-free electricity system show that combinations of commercially available tools and technologies (wind, solar, lithium-ion batteries, energy efficiency, demand flexibility, etc.) can likely achieve high-percentage carbon-free grids (perhaps 80-90 percent) cost competitively, but getting to 100 percent becomes significantly more expensive due to the variable nature of today's renewable generation sources and the resulting need to overbuild generation and storage infrastructure.

In order to achieve a 100 percent carbon-free grid, additional technologies will be needed to provide "clean dispatchable generation" and/or "long-duration storage" to avoid multi-day or seasonal incongruences between supply and demand for power. In this report, we review a set of technologies at advanced stages of development that could meet these needs, including various forms of "clean" natural gas and synthetic fuels, advanced nuclear, biomass, numerous battery technologies, gravity- and compressed air-based storage, hydrogen, and others.

We describe the basic principles of each technology for a non-technical reader and summarize their current status and projected future development based on information in the academic literature and commercial press. We also assess and compare each technology along six qualitative criteria (technical readiness, scalability, reliability, flexibility, environmental attributes, and applicability to Virginia). Economic viability based on current and future projected levelized costs is considered for a variety of use cases, including maximum utilization (baseload), low utilization (peaking), and long-duration storage (up to weeks or months of discharge capability). Although these assessments are not location dependent, we highlight key advantages and challenges for implementation in the Commonwealth of Virginia.

In order to synthesize our assessments and identify opportunities for future academic work and policy development, we score and plot the more advanced technologies across two dimensions: technical readiness, and a holistic measure of value that includes cost, environmental rating, reliability and flexibility. Results of that multi-attribute evaluation are shown in the chart below.



Allam – Allam Cycle
CAES – Compressed Air Energy Storage
NUC – Advanced Nuclear
NGCCS – Natural Gas with Carbon Capture and Storage
BECCS – Biomass with Carbon Capture and Storage

H2 – Hydrogen
RNG – Renewable Natural Gas
FB – Flow Batteries
SNG – Synthetic Natural Gas
PHES – Pumped Hydro Energy Storage

Our assessment indicates that several of these technologies could become important contributors to a carbon-free electricity system. We provide three recommendations to accelerate development and commercialization of longer term storage and clean dispatchable power technologies in Virginia.

1. Establish a policy environment that supports private investment and enables broad innovation:
   - Develop market structures that reward the full "value stack" provided by energy storage technologies,
   - Provide policy and regulatory support for pilot- and demonstration-scale projects for later-stage technologies, and
   - Promote development of infrastructure required for full commercialization.
2. Support development and commercialization of promising technologies where Virginia could provide leadership in the energy transition:
   - Maintain a broad technology and market development focus beyond lithium-ion for energy storage policy and regulation, beginning with the energy storage task force that recent legislation requires the Virginia State Corporation Commission (SCC) to convene,

- Evaluate geological capacity for long-term carbon sequestration and energy storage in Virginia,
- Leverage existing industry clusters in the Commonwealth to accelerate evaluation and, where appropriate, deployment of advanced nuclear technologies in Virginia,
- Promote development of a green hydrogen industrial network in Virginia for use in electric power generation as well as transportation, industrial processes, and other applications
- Conduct a study of CCS retrofit opportunities at Virginia's existing natural gas power plants, and
- Support expansion of the Commonwealth's renewable natural gas capacity.

3. Conduct additional modeling of the Virginia electric grid to explore pathways to a 100% clean electric supply and assess the role of longer-duration storage and clean dispatchable power in a decarbonized energy system

ACRONYM LIST

AFC	Alkaline Fuel Cell
ANS	American Nuclear Society
ApCo	Appalachian Power Company
APGA	Australian Pipelines and Gas Association
ARPA-E	Advanced Research Projects Agency – Energy
BECCS	Bioenergy with CCS
BTU	British Thermal Unit
CAES	Compressed Air Energy Storage
CAISO	California Independent System Operator
CATF	Clean Air Task Force
CCS	Carbon Capture and Sequestration
CCUS	Carbon Capture, Utilization, and Storage
CEO	Chief Executive Officer
CESA	Clean Energy States Alliance
CFPP	Carbon Free Power Project
CH_3OH	Methanol
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CSP	Concentrated Solar Power
DAC	Direct Air Capture (of CO2)
DC	Direct-current
DMME	Virginia Department of Mines, Minerals and Energy
DoD	U.S. Department of Defense
DOE	U.S. Department of Energy
EIA	U.S. Energy Information Administration
EOR	Enhanced Oil Recovery
ESBWR	Economic Simplified Boiling Water Reactor
FB	Flow Battery
FCEV	Fuel Cell Electric Vehicle
DAC	Direct Air Capture (of CO2)
FCHEA	Fuel Cell and Hydrogen Energy Association
FERC	Federal Energy Regulatory Commission
GAO	Government Accountability Office
GE	General Electric
GEH	GE Hitachi Nuclear Energy
GW	Gigawatt
H_2	Hydrogen
HALEU	High-Assay Low-Enriched Uranium
HTGR	High-Temperature Gas-Cooled Reactor
HVDC	High Voltage Direct-Current
IAEA	International Atomic Energy Agency
IHA	International Hydropower Association
INL	Idaho National Labs
IOC	Indirect Ocean Capture (of CO2)
IRENA	International Renewable Energy Agency
IRP	Integrated Resource Plan
kg	Kilogram
kW	Kilowatt
kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LCOE	Levelized Cost of Electricity
LCOS	Levelized Cost of Storage
LH2	Liquid Hydrogen
Li-ion	Lithium Ion
LMFR	Liquid Metal Cooled Fast Reactor
LNG	Liquified Natural Gas
LOHC	Liquid Organic Hydrogen Carrier
LWR	Light Water Reactor
MCFC	Molten Carbonate Fuel Cell
MCFR	Molten Chloride Fast Reactor
MW	Megawatt
MWh	Megawatt-hour
MHPS	Mitsubishi Hitachi Power Systems
MMBtu	One million BTU
MSR	Molten Salt Reactors
MW	Megawatt
Na	Sodium
NaNiCl	Sodium Nickel Chloride
NaS	Sodium Sulfur
NEI	Nuclear Energy Institute
NGCC	Natural Gas Combined Cycle
NGCCS	Natural Gas with CCS
NH_3	Ammonia
NJBPU	New Jersey Board of Public Utilities
NOAA	National Oceanic and Atmospheric Administration
NRC	U.S. Nuclear Regulatory Commission
NRDC	Natural Resources Defense Council
NREL	National Renewable Energy Laboratory
NRL	Naval Research Laboratory
PAFC	Phosphoric Acid Fuel Cell
PEM	Polymer Electrolyte Membrane
PEMFC	Polymer Electrolyte Membrane Fuel Cell
PHES	Pumped Hydropower Energy Storage

PHS	Pumped Hydropower Storage
R&D	Research and Development
RFC	Regenerative Fuel Cell
RGGI	Regional Greenhouse Gas Initiative
RNG	Renewable Natural Gas
RPS	Renewable Portfolio Standard
SCC	Virginia State Corporation Commission
SCO	Strategic Capabilities Office
SEIA	Solar Energy Industries Association
SMR	Small Modular Reactor
SNG	Synthetic Natural Gas
SoCalGas	The Southern California Gas Company
SOFC	Solid Oxide Fuel Cell
T&D	Transmission and Distribution
TES	Thermal Energy Storage
TRISO	Tri-structural Isotopic
U.S.	United States
UAMPS	Utah Associated Municipal Power Systems
UK	United Kingdom
VCEA	Virginia Clean Economy Act
VRE	Variable Renewable Electricity
VRFB	Vanadium Redox Flow Battery
WIN	Western Initiative for Nuclear
WNA	World Nuclear Association
ZBFB	Zinc-bromide Flow Battery

1 FRAMING THE ISSUE

In September 2019, Virginia Governor Ralph Northam signed Executive Order 43, "Expanding Access to Clean Energy and Growing the Clean Energy Jobs of the Future," which directed the Commonwealth to produce 100% of Virginia's electricity from "carbon-free" sources by 2050 (*Northam*, 2019). In March 2020, the Virginia General Assembly passed The Virginia Clean Economy Act (*VCEA*, 2020), and in April 2020, Governor Northam signed the legislation into law (*Virginia Office of the Governor*, 2020). Under the VCEA, the Commonwealth established a "renewable portfolio standard" (RPS) requiring the state's two largest utility companies, Dominion Energy Virginia and Appalachian Power, to produce 100 percent carbon-free electricity by 2045 and 2050, respectively. With this legislation, Virginia joined thirteen other states, the District of Columbia, and Puerto Rico with similar 100 percent clean energy commitments[1] by midcentury or earlier (*Bade*, 2019; *CESA*, n.d.). These states have been joined by a multitude of municipalities, corporations and utility companies making similar commitments (*Sierra Club*, 2016; *Climate Group*, 2015). While the timelines and definitions of what qualifies as "clean," "renewable," or "carbon-free" vary, the trend is clear—major institutions are getting ambitious about eliminating carbon emissions in the power sector.

This raises a question: is it feasible to run the electric grid on 100% clean energy? The good news is that dramatic increases in electricity generation from solar and wind power are already occurring, as these technologies are now cost-competitive on a levelized basis with traditional sources of generation in many areas of the country and around the world. In order to address the intermittent nature of solar and wind generation, grid operators have learned to become more flexible, enabling a higher percentage of these power sources on the grid. Getting to 100% clean or renewable electricity may not be practical with existing energy infrastructure and technology, though, assuming a large proportion of generating assets will be from intermittent sources. A combination of the following approaches will likely be required to reach the goal of 100% clean electricity at scale:

1. **Increases in energy efficiency and widespread use of demand response.** Reducing and shifting the electricity demand profile to more closely match the supply profile of solar and wind generation is critical with high penetrations of intermittent generation sources.
2. **New electricity transmission infrastructure.** A regional or national enabler of higher penetrations of renewables is a buildout of the electricity transmission infrastructure to connect heavy supply regions (e.g. wind in the Dakotas) to heavy demand centers (e.g. midwestern cities), or connecting regions with different temporal profiles of intermittent generation (e.g. Southwest sun and Midwest wind). In order to comply with the VCEA, Virginia's electric utilities could build enough renewable capacity in Virginia to meet the 80% target for in-state generation and then import enough out-of-state renewable sources to meet the remainder of Virginia's demand at any given time. The difficulty of this approach is that transmission buildouts have proven expensive and challenging due to interstate permitting battles and local siting concerns, and such a plan relies on asynchronous availability of excess clean energy supplies from other regions (*Linares*, 2016).
3. **Overbuilding of intermittent generation sources.** Building excess solar and wind capacity so that sufficient electricity generation is available at all times of the day is a potential solution; however, the economics of such a plan are questionable (*Frew et al.*, 2016).
4. **Energy storage and clean dispatchable power**. Interregional transmission and curtailment of renewable generation during periods of oversupply could be abated by the buildout of energy

[1] Several terms are used in legislation, including "carbon-free electricity," "clean energy," "renewable energy," and "net-zero (greenhouse gas) emissions."

storage capacity or the conversion of electricity into renewable fuels. While some storage technologies, in particular lithium-ion batteries, have declined significantly in cost, they remain cost-effective only in shorter-duration applications with frequent charge and discharge cycles. Utility-scale storage or clean dispatchable power required over an extended duration, such as during multi-day periods of cloudy skies or low wind conditions in the winter, cannot yet be cost-effectively addressed with commercially available technologies.

As more jurisdictions set increasingly ambitious renewable generation goals and mandates, policymakers and energy researchers have become increasingly interested in exploring potential pathways to achieve these goals.

Frew et al. use a linear programming model to "find the least-cost portfolio of generators (baseload, dispatchable, and variable), storage, and transmission that meet the electric load and reserve requirements in each hour while attaining a given RPS target" across the contiguous United States. They find that RPS requirements up to 80% are achievable at a reasonable cost (~30% cost increase vs. no RPS) assuming increased flexibility from vehicle electrification and more widespread regional aggregation via transmission buildout. Importantly, the step from 80% to 100% RPS increases cost roughly 2x and increases renewable overgeneration roughly 3x (*Frew et al.*, 2016).

Mai et al. model the U.S. electricity system on an hourly basis, concluding that a national standard of 80% renewable electricity is feasible by 2050 under a variety of transmission and flexibility constraint scenarios, but they do not consider cases above 90% penetration. In most of the scenarios considered, the researchers assume increases in energy efficiency, vehicle electrification, grid flexibility, and transmission expansion. Interestingly, this study was conducted in 2012 and used assumptions already proven too conservative regarding the falling cost of wind, solar, and batteries (*T. Mai et al.*, 2012).

Jenkins et al. review 40 studies published since 2014 (14 of which consider all or some portion of the United States), which explore pathways to "deep decarbonization" of the electricity system, defined as 80-100% of power generated from zero-carbon resources. These studies almost uniformly conclude the following:

- Challenges associated with variable renewable electricity (VRE) increase nonlinearly with increases in VRE penetration, with up to weeks-long "gaps" between VRE supply and electricity demand depending on the region
- Continent-scale transmission expansion could be required to achieve very high penetrations of VRE
- Increases in demand flexibility can help substantially to solve VRE challenges on an intra-day basis
- Highly VRE-dependent scenarios could require an overbuild of 3-8x peak demand and could result in overgeneration up to 40% of annual U.S. power demand

Jenkins et al. conclude with a recommendation that a variety of low-carbon technologies (both "firm" and variable) should be supported in order to maximize the probability that one or more of them become viable to enable an affordable, reliable, zero-carbon electricity system (*Jenkins et al.*, 2018).

Given the projected costs of a high-VRE grid even with improvements in energy efficiency, increased demand flexibility and investments in transmission, we explore the view of Jenkins and others that either "firm" (clean) capacity or "seasonal" storage are needed to complement VRE and lower the eventual total system cost. Accordingly, we evaluate the feasibility of clean, dispatchable power sources on the grid, including both carbon-free (or near carbon-free) generation technologies and longer-duration energy storage. There are significant challenges associated with both sets of technologies: dispatchable generation may face lower utilization if used primarily for a more renewables-balancing, flexibility-focused role; and longer-duration storage technologies are not yet commercialized at scale and currently have cost or scalability limitations. Regardless of these challenges, a mix of long-term storage and dispatchable clean power technologies will likely be required for Virginia to achieve its legislative mandate at reasonable cost. This report seeks to understand the current and future projected state of these technologies to provide guidance for further research and investment.

2 METHODS

In order to explore the viability of clean dispatchable generation and longer-duration storage technologies, we first established the set of technologies to be evaluated. As the set of possible technologies is large and diverse, we identified a mutually exclusive yet relatively exhaustive list of technologies that are mature enough to have demonstrated more than lab-scale research and development (R&D) and that are fully dispatchable. For storage technologies, we focus on solutions with the ability to store and discharge energy longer than current commercial use cases (four hours). The final set of technologies assessed is shown in Figure 1.

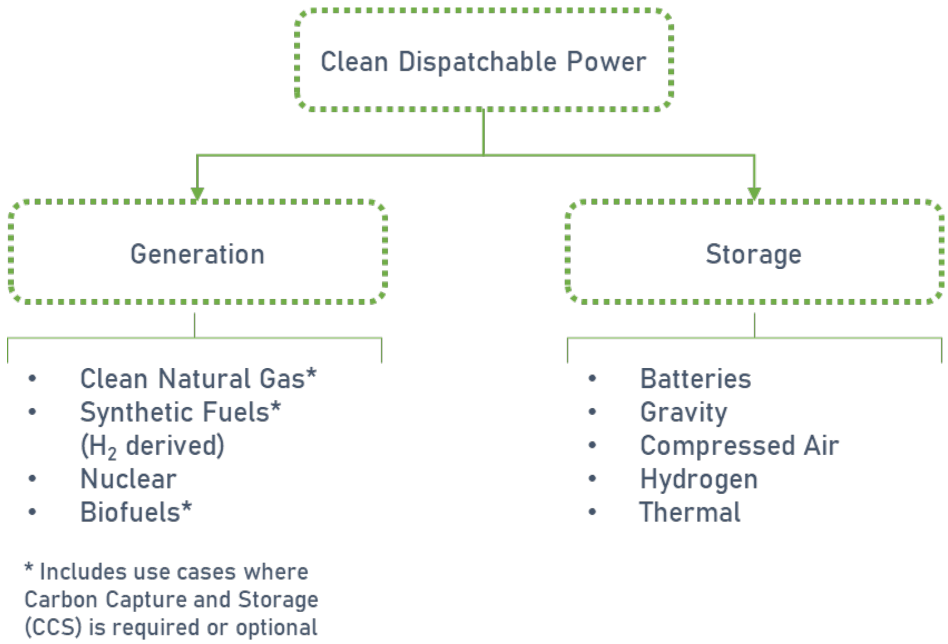


Figure 1: Summary of Clean Dispatchable Technologies

For each technology, we review the literature to describe the basic principles for a non-technical reader and summarize the current and projected future state of the technology. Although this analysis is not location dependent, we focus on key advantages and challenges for implementation in the Commonwealth of Virginia.

Next, we review the literature to assess and compare each technology along six qualitative criteria: technical readiness, scalability, reliability, flexibility, environmental rating, and applicability to Virginia. We also review the literature to assess and compare the current and future projected levelized cost of each technology for a variety of use cases, including maximum utilization (baseload), low utilization (peaking), and long-duration storage (up to weeks or months of discharge capability).

Finally, we synthesize the assessments to make recommendations for future academic work and policy consideration. In making these recommendations, we specifically consider and comment on the latest legislation and utility planning processes in Virginia, as well as the results of similar studies conducted in other states.

3 TECHNOLOGY SUMMARIES

We begin with basic explanations of the critical elements and options available for each technology, first examining "clean dispatchable generation" technologies and then examining "energy storage" technologies. Both sets of technologies present opportunities to address the intermittency limitations of traditional renewable generation technologies. The technology selections and related descriptions are informed by the latest available literature and commercial press but may not be exhaustive or technically complete. A further, more detailed investigation of each technology should be undertaken to fully understand its potential in Virginia and beyond.

3.1 Clean Dispatchable Generation

Traditional sources of electricity (coal, natural gas, etc.) present many well-recognized problems, perhaps most notably the emission of greenhouse gases and other known air and water pollutants. These fuel sources rose to prominence in the power sector for good reason—they were relatively cheap, abundant, and efficient sources of "dispatchable" electricity. Coal and natural gas are readily stored, and power generation is not dependent on the availability of the resource at any given moment in time. Renewable energy technologies (solar and wind in particular) are becoming increasingly cost-competitive with traditional fossil fuel technologies, but they face the fundamental shortcoming of being intermittent. Renewable power, without long term storage, is not "dispatchable" in the sense that it cannot be produced on-demand (i.e. when the sun is not shining or the wind is not blowing).

While many in the industry are still studying and modeling the exact levels of purely renewable generation that is possible, the feasibility of high levels of renewable penetration is becoming widely recognized (*Jenkins et al.*, 2018). Combinations of sun, wind, water (hydroelectric), energy efficiency, demand response, and short-duration batteries are paving the way to a low-carbon power grid. However, it remains likely that some portion of power generation needed to meet demand will be more cost effective through other "clean dispatchable generation" technologies rather than the overbuilding of renewable generation and short-duration battery storage that would be needed otherwise. In the following sections, we describe four of the leading technology solutions that would provide (arguably in some cases) clean dispatchable generation—power generation that emits net zero greenhouse gases and is fully dispatchable. These include "clean" natural gas, hydrogen-derived synthetic fuels, nuclear, and biomass.

3.1.1 Clean Natural Gas

"Clean" natural gas may seem to be a misnomer. Although the transition from coal to natural gas as the leading source of power generation in the United States has reduced system-level carbon emissions, natural gas is still a significant emitter of carbon dioxide (CO_2). In addition, methane leakage in the natural gas extraction process and distribution infrastructure is increasingly being identified as a major source of greenhouse gas emissions (*Hight et al.*, 2020). But there are methods to make natural gas "clean."

In the following sections, we lay out the current state of natural gas in Virginia, discuss the economic problem of potentially stranded natural gas infrastructure, and describe three pathways to (near) zero emission or "clean" natural gas. The first is by cleaning up the emissions 'on the way out' through carbon capture technology. The second is by cleaning up the fuel 'on the way in' by (i) converting biogas into biomethane or (ii) producing synthetic gas using renewably produced hydrogen and captured CO_2. The third is an entirely new process called the Allam Cycle that builds carbon capture directly into combustion.

3.1.1.1 The State of Natural Gas in Virginia

Natural gas now dominates Virginia's electricity mix, more than doubling its share from 2010 to 2018 to generate more than 50 percent of Virginia's power (*EIA*, 2020b). According to the Commonwealth of Virginia's 2018 Energy Plan, "interstate and intrastate natural gas pipelines in Virginia consist of 3,000 miles of high-pressure pipelines and over 40,000 miles of lower-pressure distribution pipes connecting 1.2 million customers" (*Godfrey*, 2018). To put it simply, natural gas comprises a significant portion of the current power generation and heating fuel infrastructure in the Commonwealth, and the existing infrastructure must be addressed as part of any plan to transition to renewable energy.

We investigated the state's largest utility companies' latest integrated resource plans (IRPs) to determine the current outlook for new natural gas generation in Virginia. Appalachian Power (or "ApCo") makes no mention of new natural gas in their latest filing (*APCO*, 2019) and indicates plans to retire 455 megawatts (MW)[2] of natural gas power generating capacity in 2026. Dominion Energy Virginia (or "Dominion") references plans to build 2,425 MW of new natural gas capacity by 2044 in their updated August 2019 filing (*Dominion*, 2019c), but a Dominion filing after the passage of the VCEA casts some doubt on those plans (*SCC*, 2020). Dominion released its initial 2020 IRP in May 2020 (*Dominion*, 2020), which includes the buildout of 970 MW of new natural gas turbine capacity to maintain grid reliability. Dominion acknowledges that new technologies may become viable that limit these facilities' normal operating lives or allow them to be retrofitted for "clean" fuels, including renewable natural gas.

3.1.1.2 The Stranded Asset Problem

A simple question is raised in light of the VCEA: are new or even existing natural gas power plants congruent with the requirements of the legislation? Virginia's power generation mix in 2018 was ~53% natural gas, ~31% nuclear, ~10% coal, and 7% "other" (including hydro, biomass, petroleum, and solar) (*EIA*, 2020b). The legislation's RPS calls for 30% renewables by 2030 and 100% by 2050. Notably, nuclear is not included in the legislation's qualified renewable or clean resources. Generation from existing nuclear facilities is excluded from the denominator of the RPS calculation, effectively grandfathering them into the requirement (i.e. 30% of all *non-nuclear* electricity generation must be renewable by 2030) (*Williams Mullen*, 2020; *EIA*, 2020b).

Assuming Virginia can meet its 30% clean electricity target in 2030, much is uncertain through 2050. This is particularly true on the demand side where electrification of transportation, buildings, and other industries has the potential to dramatically shift the current electricity load profile. Regardless, it is clear that the state's existing natural gas generation fleet is at risk of becoming either economically or legislatively obsolete during this time period; if any new natural gas generation is contemplated, it should be assessed in light of a shorter-than-typical lifespan or designed with clean fuels or negative emissions technologies in mind. For our purposes, this highlights the importance of evaluating whether new or retrofitted "clean" gas facilities can be built at a cost that is competitive with renewables affected by increasing levels of curtailment.

3.1.1.3 Pathways for "Clean Natural Gas"

Natural gas comprises multiple hydrocarbons—primarily methane (CH_4). Natural gas is typically processed to separate the methane from other contaminants such as hydrogen sulfide, CO_2, and oxygen (*EIA*, 2006). Although there are slight differences in the thermal content of pipeline-quality

[2] Any notation of power in this paper (i.e. kW, MW, GW) refers to electric (rather than thermal) output.

natural gas and pure methane, this paper considers these gases equivalent for use in the energy system.

3.1.1.3.1 Carbon Capture and Sequestration (or Utilization)

Carbon capture and sequestration (CCS), also commonly referred to as carbon capture, utilization, and storage (CCUS), is comprised of up to four stages as evident from its name.

Capture. This first stage involves the separation of CO_2 from other gases produced at large industrial process facilities such as coal and natural-gas-fired power plants, steel mills, cement plants and refineries. Carbon capture technology has existed for decades, primarily in industrial applications, but its commercial-scale application to power generation is limited, with only one project operating in the U.S. as of 2018—the Petra Nova plant near Houston, TX, owned by NRG. Petra Nova is a retrofitted coal-fired facility that sells its captured CO_2 to the oil industry for use in enhanced oil recovery (EOR) operations (*Global CCS Institute*, 2017). A wide variety of capture and separation technologies are still under development and offer potential for further innovation, but the most common approach is post-combustion capture using a liquid sorbent. The 'capture' portion of CCS accounts for roughly 80% of the cost (*Leung et al.*, 2014).

Transport. Once separated, the CO_2 is compressed and transported via pipelines, trucks, ships or other methods to a suitable site for utilization or geological storage. This transportation infrastructure is a key hurdle for CCS deployment at scale. According to a U.S. Congressional Research Service report, "even though regional CO_2 pipeline networks currently operate in the United States for EOR, developing a more expansive network for CCS could pose regulatory and economic challenges. Some observers note that development of a national CO_2 pipeline network that would address the broader issue of greenhouse gas reduction using CCS may require a concerted federal policy beyond the current joint federal-state regulatory policy."

Utilization (optional). Commercial use cases for CO_2 are not widespread, but it can be used as a value-added commodity in industrial and agricultural processes (by producing ammonia or urea), beverage carbonation, refrigerants, fire extinguishing gases, or other chemical feedstocks. Only a subset of these commercial uses results in long term sequestration of the captured CO_2. The most commercially mature use case for CO_2 is in EOR operations in the oil and gas extraction industry, in which CO_2 is injected into existing wells to materially increase yield. This use case has limited applicability to Virginia unless transportation infrastructure were developed to access oil or gas industry hotspots.

Storage (if not utilized). According to a 2014 review by Leung, three geological formations are commonly considered for CO_2 storage: depleted (or nearly depleted) oil and gas reservoirs, unmineable coal beds, and saline aquifers (*Leung et al.*, 2014). While the oil, gas, and coal injection methods are more financially viable (additional revenue streams and more existing infrastructure in place), saline aquifers represent a far larger potential storage capacity (*Folger*, 2018). More research must be done to understand what, if any, feasible geological storage options exist in Virginia. Although costs will vary widely by application, a general observation in the literature is that transportation and storage make up roughly 20% of the cost of CCS.

CCS represents a relatively well-known set of technologies. It has been and continues to be supported at the federal level through programs like the 45Q tax credit (under which investors receive credits on a \$/metric ton of CO_2 sequestered basis) (*Jones & Sherlock*, 2020), and \$100+ million in U.S. Department of Energy (DOE) grants for cost-shared R&D (*DOE*, 2019b). Continued potential improvements in the technology of CCS and the development of CCS projects are well-documented including streamlined procurement, reduction in structural steel, standardization of modular components, and improvements in efficiency and performance of solvents which reduce the energy needed to run the capture process (otherwise known as the "energy penalty") (*Global CCS Institute*, 2017). When paired with an existing generation technology like natural gas combustion, CCS presents a fully scalable, reliable, and flexible alternative that is (arguably) clean.

Considerable hurdles remain to widescale commercial deployment. Capturing carbon emissions from a power plant is an inherently expensive proposition: CCS plants require power to run the CCS process (reducing the efficiency of the power plant), not to mention the capital and operating cost of a significant additional industrial process or the costs of scaled transportation infrastructure and access to feasible utilization or storage. Besides the cost and geographic dependence of CCS, there are remaining environmental concerns. The latest CCS technology only removes ~90% of CO_2 emissions, meaning CCS is not a truly zero-carbon process. Removing carbon 'on the way out' does nothing to resolve emissions associated with natural gas extraction, processing, and transportation to power generation facilities (including the significant problem of methane leakage and intentional flaring). The capture process itself results in emissions that must be mitigated (like amine from the absorption separation process), and geological storage techniques carry the risk of leakage.

The cost of building coal and natural gas facilities with CCS is high (around 2x the cost of a plant without CCS on a levelized cost of electricity [LCOE] or $/MWh basis) and according to NREL is projected to remain high (*NREL*, 2019). While retrofits of the existing natural gas capacity in Virginia would appear to be a more cost-effective path, such retrofits have never been done, and research indicates retrofits are nearly as expensive as greenfield plants due to site-specific limitations of integrating CCS where it was not originally designed (*Rubin et al.*, 2015). Perhaps more improvements are possible, but until wider commercialization occurs, it is difficult to forecast. Regardless, given its technical feasibility and potential scalability, greenfield natural gas generating facilities with CCS might reasonably be considered a benchmark against which to compare other clean dispatchable and long-term energy storage options. As discussed more fully in the recommendations, the cost of retrofitting Virginia's existing natural gas fleet should be studied further.

3.1.1.3.2 Clean Fuels

While CCS cleans up natural gas combustion emissions 'on the way out,' it is also possible to clean up the fuel 'on the way in' by using methane produced in a sustainable way (either through capture or methanation). Both technologies possess the critical feature of direct substitution into existing natural gas infrastructure, including power plants and pipelines. For this reason, their feasibility hinges primarily on the production of the fuels themselves.

3.1.1.3.2.1 Renewable Natural Gas (from Biofuels)

Renewable natural gas is a term most often used to describe biomethane derived from biogas. The primary production process used to generate biogas is anaerobic digestion, in which a feedstock (such as waste water, livestock waste, food waste, etc.) is broken down by microorganisms in the absence of oxygen to produce biogas (50-70% methane, 30-40% CO_2) and digestate (used for soil amendments and fertilizers). Rather than anaerobic digestion, thermal gasification could be used to convert lignocellulosic feedstocks like switchgrass (which have a higher methane content) into biogas, although this process is less well-developed and comes with the familiar land use constraints associated with energy crops. Once produced, the raw biogas can be used for local distributed power and heat applications, or it can be further refined into biomethane that is compliant with natural gas pipeline standards, also known as renewable natural gas (RNG).

There are over 2,000 existing biogas facilities in all 50 states, including 63 in Virginia. Dominion Energy, the largest utility company in Virginia, is experienced in the biogas sector and in October 2019 doubled its commitment to a $500 million joint venture with Smithfield Foods to become the largest producer of RNG in the country (*Dominion*, 2019a). According to the National Renewable Energy Laboratory (NREL), biogas has the potential to replace ~5% of the natural gas consumption in the U.S. power sector (*NREL*, 2013). And according to the American Biogas Council, the 63 existing facilities in Virginia have the potential to scale by roughly 4x to produce roughly 40 million MMBtu of biogas (*American Biogas Council*, 2020). Depending on efficiency factors assumed, this would generate roughly 3,000-6,000 GWh of electricity, or roughly 3-6% of current power demand in Virginia.

Biogas has many attractive features. The technology utilizes a waste product and converts it into useful energy in a way that, at least with respect to those processes, is carbon neutral.[3] Biogas infrastructure is often sited in rural, agricultural areas, creating economic development opportunities for regions in need of it. Technically, the ability to directly substitute RNG for fossil natural gas in existing pipelines and power plants is a major advantage. There are limited incremental costs of new transportation or power plant infrastructure and the chief production technology—anaerobic digestion—is relatively mature and at commercial scale today.

According to NREL, the cost to produce one MMBtu of RNG varies significantly depending on the feedstock (from ~$2/MMBtu for landfill gas to ~$11/MMBtu for gas from dairy manure). Adding roughly $3.50/MMBtu in transportation and storage costs, this brings the total fuel cost to roughly 2-5x the cost of fossil natural gas at current prices (*Jalalzadeh-Azar*, 2010). If fuel costs are roughly 80% of LCOE for a natural gas-fired power plant, this equates to a roughly 1.5-3x LCOE cost premium relative to existing natural gas. According to an International Renewable Energy Agency (IRENA) report in 2017, 30-40% in additional cost reductions are possible, which could bring these solutions into cost competitiveness with today's leading generation technologies (*IRENA*, 2017a).

Biogas presents considerable challenges in monitoring and enforcement. If existing waste sources of methane (a stronger greenhouse gas) are captured and converted into biogas, which emits CO_2 when combusted (a weaker greenhouse gas), biogas is a net benefit. But if new sources of organic material are produced in order to create biogas, and there is some leakage of methane through the supply chain, biogas would result in net emissions. In addition, the waste products and effluents from biogas production must be carefully monitored and sequestered for agricultural use rather than emitted into water streams. Finally, although RNG can technically achieve pipeline-quality standards, it is not universally allowed by utilities and regulators to be injected into all transmission and distribution infrastructure, which would be necessary to fully capitalize on commercialization at scale.

Notwithstanding the environmental risks and scale limitations, it is clear that biogas could be a viable solution to at least a portion of the "gap" required to get to 100% clean energy. The costs are not far from today's generation technologies and could very likely be competitive in a future grid with a high penetration of renewable generation sources. There is also the potential for valuable economic benefits for rural communities, which is a priority in the Virginia legislation.

3.1.1.3.2.2 Synthetic Methane

Methane can be synthesized into synthetic natural gas (SNG) with a process known as "methanation" through a chemical reaction with hydrogen and CO_x. This process is detailed further in a broader discussion of synthetic fuels (Section 3.1.2).

[3] Carbon neutrality is maintained since the carbon emitted by combustion was originally fixed from the atmosphere by the organic material used to create the biogas.

3.1.1.3.3 The Allam Cycle

While CCS cleans emissions 'on the way out,' and either RNG or SNG provide clean fuel 'on the way in,' there are processes under development to remove CO_2 as part of the combustion process itself. An innovation called the Allam Cycle, pioneered by Rodney Allam and NET Power (whose parent company is 8 Rivers Capital), aims to do exactly this. The Allam Cycle is a "high-pressure, highly recuperative, oxyfuel, supercritical CO_2 cycle" (*NetPower*, n.d.). High pressure and supercritical temperature are used to run the turbine on CO_2 rather than steam. "Oxyfuel" refers to the use of pure oxygen for mixing with the natural gas for combustion (achieved with an air separation unit) rather than air, which eliminates harmful NO_x emissions. And the process is "highly recuperative" because the majority of the CO_2 output is recycled back into the process for combustion again. The CO_2 that is not recycled can be easily re-pressurized to pipeline-quality for sequestration or use (*Roberts*, 2018).

There are many purported benefits of the Allam Cycle over traditional natural gas power generation. NET Power claims that Allam Cycle plants are expected to perform at 59% efficiency (a measure of the electricity output of the plant relative to the heat value of the fuel used)—in line with the latest advanced natural gas combined cycle plants which perform near 62%. This is particularly important considering our interest in comparing the Allam Cycle to CCS on traditional gas plants, which comes at an energy penalty (because the CCS process uses some of the plant's electricity) that reduces efficiency below 50%. In addition, Allam Cycle plants are designed with a similar physical footprint to traditional gas plants and smaller than traditional plants with CCS. NET Power claims that the capital cost of an Allam Cycle plant should be lower than a traditional plant. Finally, Allam Cycle plants use significantly less water than traditional gas plants (since Allam plants use water only for cooling and traditional plants must boil large volumes of water to run their steam turbines). In fact, with a small efficiency penalty (~2.5% according to NET Power), Allam plants can use air cooling and become a net producer of water.

Since its founding in 2008, NET Power has raised more than $160 million, and in 2016 partnered with Exelon Generation, CB&I, and Toshiba to construct a 50 MW demonstration plant in La Porte, TX. In 2018, this plant achieved 'first fire' and began undergoing a battery of tests to measure its performance. As of May 2020, no official results or pronouncements had been made regarding the performance of the demonstration plant, but NET Power has said it plans to use the plant as an ongoing test site. The company is in the early stages of development for a 300 MW commercial scale facility targeted for operation in 2022 (*Patel*, 2019).

The Allam Cycle holds promise as a cost-effective replacement for traditional natural gas-fired power plants with all of the benefits (reliability, flexibility) and far fewer harms (limited water use, no air pollutants) and could be a superior alternative to CCS (higher efficiency, lower cost). To the extent Allam plants use fossil natural gas, though, they are subject to the same environmental questions around the supply chain of natural gas—including fugitive methane emissions and flaring. Allam plants will also rely on the same CO_2 transportation and storage infrastructure buildout as CCS, which must be factored into their cost. While the promise of this technology is legitimate, commercial deployment is still needed to substantiate the bold claims being made by the technology's developers and proponents.

3.1.2 Synthetic Fuels (Hydrogen derived)

The natural formation of hydrocarbon fuels beneath the earth's crust (what we refer to as fossil fuels) happens over geologic timescales as organic matter decays and undergoes a series of chemical reactions. These same reactions can be reproduced to create "synthetic" fuels on-demand with a feedstock of hydrogen and carbon compounds (typically CO or CO_2).[4] Despite emitting greenhouse gases to the environment when combusted, the overall cycle can be considered carbon neutral when the energy input required to create these fuels is carbon-free.

The types of hydrocarbons that can be synthesized are essentially limitless – from simple compounds such as methane to complex (long-chain) compounds such as diesel fuel and gasoline (*Shell*, 2017). As this paper is focused on electricity production, only those fuels that are typically (or proposed to be) used in the power sector are discussed in detail: hydrogen[5], methane, and methanol.

As a necessary step of creating a synthetic fuel is producing pure hydrogen, we first discuss the production, transportation, and storage of hydrogen. Note that hydrogen has the potential to play a very diverse role within the energy system. This section, aside from introducing the basics of hydrogen, focuses on the molecule as a fuel and as a feedstock to synthetic hydrocarbon production. Section 3.2.4 briefly discusses hydrogen's role as a method of energy storage. This section will additionally discuss the sourcing of CO_2 to enable these chemical reactions.

3.1.2.1 Hydrogen

Hydrogen should not be thought of as an energy source, but rather as an energy carrier. Although it is the most abundant element in the universe, hydrogen does not exist in its natural gaseous form on earth (diatomic hydrogen – H_2). Rather, the gas must be chemically extracted from other compounds – typically hydrocarbons or water. Producing hydrogen requires an energy input and its subsequent use provides an energy output; therefore, it can be considered a form of long-term energy storage. One particularly important advantage is that when the energy stored in hydrogen is released through combustion or converted to electricity in a fuel cell, the process is truly clean – it produces only water vapor.

3.1.2.1.1 Production

3.1.2.1.1.1 Production Methods

Hydrogen today is predominantly produced from fossil fuels – typically natural gas or coal. This process is commonly known as *grey hydrogen*, or when used in combination with carbon capture and storage (CCS), *blue hydrogen*. When produced from water and a clean electricity source, the resulting gas is known as *green hydrogen*.

Grey Hydrogen. The most common way of producing hydrogen is by steam reforming of methane, as this is an established industrial process and is economical compared to other methods. CO_2 is emitted to the atmosphere during this process. There are other less frequently used methods to produce grey hydrogen, including gasification of coal, all of which generate greenhouse gas emissions.

Blue Hydrogen. As CCS technology becomes more mature, there is increasing focus on the generation of blue hydrogen to mitigate the climate impact of current production methods. By using mature, large-scale processes to extract hydrogen from fossil fuels, some argue that using carbon capture technologies as part of these processes is the best way to scale clean hydrogen production while the cost of green hydrogen comes down.

An alternative method of blue hydrogen production is proposed by 8 Rivers Hydrogen, whose parent company 8 Rivers Capital is also investing in the Allam Cycle for natural gas plants (discussed in

[4] This paper will focus on CO_2 as a feedstock to synthesis of hydrocarbons, as the recycling of CO_2 through either carbon capture of emissions or from the atmosphere is a common use case for the mitigation of climate change.

[5] Hydrogen is an element, not a hydrocarbon; however, hydrogen is required as a feedstock to the synthesis reaction of hydrocarbons. Since direct combustion of hydrogen gas is a feasible method of power generation, it is discussed in the context of synthetic fuels.

Section 3.1.1.3.3). Their process, known as 8RH2, reforms natural gas with pure oxygen and uses cryogenic CO_2 capture. The company claims this process is cheaper and cleaner than traditional steam methane reforming approaches, but at the time of writing no pilot projects had been built.

Green Hydrogen. Using electricity from a carbon-free power source such as solar, wind, or nuclear, an electrolyser breaks water molecules down into its component parts – hydrogen and oxygen; this process is known as electrolysis. While electrolysis is a proven technology, it has not yet been deployed in a cost-competitive way. The high cost of green hydrogen is primarily due to the large amount of energy required to disassociate water molecules; typical electrolyser units require ~50 kWh/kg of hydrogen produced, with a theoretical limit of 39.4 kW/kg (*Harrison et al.*, 2010). These energy requirements are significantly higher than blue hydrogen production methods. Steam methane reforming and coal gasification with CCS require only 2 kWh/kg and 4 kWh/kg of electricity consumption, respectively (*Global CCS Institute*, 2018). In the context of an electric grid with high penetration of renewables, the marginal cost of electricity during periods of high renewables output will be quite low, and the higher energy requirements for production of green hydrogen may become less of a concern. Nevertheless, green hydrogen may always be more expensive on an unsubsidized basis than hydrogen extraction from fossil fuels and will likely require government incentives or regulation (e.g. carbon pricing or binding limits on greenhouse gas emissions) to become competitive in the marketplace. Appendix C provides a brief summary of the various types of electrolysers.

The economic attractiveness of green hydrogen production is highly dependent on electricity prices, as production dominates the total cost of the hydrogen value chain. Bloomberg New Energy Finance (BNEF) estimates the levelized cost of large-scale green hydrogen production is between $2.50 and $4.50 per kg (for reference, 1 kg of hydrogen contains roughly the same energy content as 1 gallon of gasoline) (*NREL*, 2008; *BNEF*, 2020). These costs are higher than those associated with blue hydrogen production (natural gas or coal with CCS). By 2030, green hydrogen costs could decline to $2/kg (roughly equivalent with blue hydrogen costs) and by 2050 reach $1/kg, becoming the lowest cost method of clean hydrogen production. This cost curve supports the premise that a path to large scale clean hydrogen production could involve using blue hydrogen production technologies initially to support development of hydrogen networks and end use applications, eventually migrating to green hydrogen production as electrolysis technologies continue to improve and surplus, low-cost renewable generation becomes more widely available on the grid.

BNEF estimates that $150 billion in cumulative subsidies to 2030 are required in order to make clean hydrogen (green and blue) competitive with natural gas prices in many areas of the world (*BNEF*, 2020). There have recently been several large-scale projects announced related to the production and utilization of clean hydrogen:

- The H-vision project, a consortium of 16 companies, seeks to use blue hydrogen to supply the chemical industry, refineries, and power plants in the Port of Rotterdam (*H-Vision*, 2019). The ambitious project's aim is to support the low-carbon hydrogen economy with technology that is available today while paving the way towards the large-scale use of green hydrogen.
- Shell Netherlands, Gasunie, and the Port of Groningen are founding partners of the NortH2 consortium and are performing a feasibility study to develop what would be the largest green hydrogen project in the world. They hope to develop a "European Hydrogen Valley" cluster with 3 to 4 GW of offshore wind capacity established in the North Sea by 2030, and potentially expanding to 10 GW by 2040 dedicated to green hydrogen production (*Parnell*, 2020).

- Australia has major ambitions as a hydrogen production and transportation hub. The government is preparing a National Hydrogen Strategy that will position the country to grow both domestic production and export markets (*Energy Networks Australia & APGA*, 2019). They are embarking on several demonstration projects, including both green and blue hydrogen, to demonstrate the viability of these technologies by the mid-2020s. One major project will produce hydrogen from brown coal at a mine in Victoria. The pilot project, which will use CCS, is co-funded by Kawasaki Heavy Industries and is intended to provide a steady supply of hydrogen to Japan as they develop their hydrogen economy (*Maisch*, 2020).

3.1.2.1.1.2 Production Location

Both centralized and distributed production facilities are expected to play a role for the use of hydrogen as an energy carrier (*DOE*, n.d.-b).

<u>Centralized Production</u>. Large central hydrogen production facilities require a higher up-front capital investment but will benefit from economies of scale. There will need to be a substantial network of hydrogen transport and delivery infrastructure to enable this model. Existing natural gas infrastructure may serve this purpose, at least initially, given the potential for blending low concentrations of hydrogen (5-15%) into natural gas pipelines (*Melaina et al.*, 2013).

<u>Distributed Production</u>. For certain applications, such as vehicle refueling stations, hydrogen may be produced on-demand at distributed locations. In addition, the distributed model will be used when green hydrogen is used as a form of long-term energy storage – created using electrolysis of water and converted back to electricity through a fuel cell or direct combustion. This may be the most viable approach for introducing hydrogen into the energy system while market demand and the supporting infrastructure are still developing.

3.1.2.1.2 Transportation and Storage

Hydrogen's low density makes it considerably harder to store and more expensive to transport than fossil fuels. According to BNEF, storing hydrogen in large quantities will be one of the most significant challenges for a future hydrogen economy. Assuming hydrogen would replace natural gas by 2050, the storage infrastructure buildout would cost an estimated $637 billion (*BNEF*, 2020). And depending on the transportation method utilized, an additional major infrastructure investment would be needed.

<u>Transportation</u>. Hydrogen can be transported by pipelines, trucks, or tanker ships in various states. In small volumes and at short distances, the most economic option would likely be to compress the hydrogen and transport using trucks. At longer distances on ground, hydrogen can be diffused into what is known as a Liquid Organic Hydrogen Carrier (LOHC). These compounds "carry" hydrogen in a stable state and allow a higher amount to be carried per unit volume (i.e. higher density). At higher volumes, transmission and distribution pipelines could be a cost-effective option. Notably, hydrogen flows nearly three times faster than methane (natural gas) through pipes. At inter-continental scales, hydrogen can be transported via shipping either through liquefication (similar to liquified natural gas [LNG]) or through a chemical conversion to ammonia (NH_3) (*BNEF*, 2020).

<u>Storage</u>. Similar to transport, hydrogen can be stored in various states – gas, liquid, or solid. In its gaseous form, the molecule can be pressurized and stored in built-for-purpose containers or alternatively pumped into salt caverns, depleted gas fields, or rock caverns. The natural formations are, of course, geographically limited but offer the advantage of storing large amounts of hydrogen on a seasonal timescale. In a liquid form, hydrogen can be cryogenically cooled into liquid hydrogen (LH2), combined with nitrogen in a chemical process to produce ammonia, or stored in LOHCs. These storage methods are more expensive than keeping hydrogen as a gas but offer the advantage of large-volume

storage without geographical limitations. In addition, hydrogen may be converted to various metal hydrides and stored as a solid. A DOE study discusses promising candidates of metal hydrides as a use for hydrogen storage, but further R&D is needed to find a material with suitable properties that meets all of the DOE's technical targets (*Keller & Klebanoff*, 2012).

3.1.2.1.3 Applications of Hydrogen

Hydrogen is versatile and can be used across the entire energy landscape. The U.S. Hydrogen Roadmap, a product of 20 companies and organizations, describes a vision for the growth of the hydrogen economy within the United States (*FCHEA*, 2020). Hydrogen is a unique energy carrier with applications across sectors of the economy, including the centralized power system, off-grid power, buildings, transport, and industrial processes.

3.1.2.1.3.1 Power Generation and Grid Balancing

Hydrogen can provide opportunities for storing large amounts of energy over long durations, including seasonal storage. A primary use case is to produce hydrogen from electrolysis using electricity during times of excess wind and solar production, which would otherwise be curtailed. The hydrogen could then be used as a fuel when needed on the grid – either directly through combustion or in a fuel cell. Significant curtailment of power is already occurring in some regions of the U.S., particularly in California, with very low or negative wholesale market prices on especially sunny and windy days. According to a study sponsored by Mitsubishi Hitachi Power Systems (MHPS), hydrogen electrolysers will become competitive when renewables penetration reaches approximately 40%, when longer (i.e. multi-day) periods of surplus and deficit of electricity begin to form (*MHPS*, 2019). Appendix D provides a brief summary of the various types of fuel cells. Hydrogen can also be considered a source of distributed power for off-grid applications or backup power.

3.1.2.1.3.2 Transportation Fuel

Fuel Cell Electric Vehicles (FCEVs) powered by hydrogen could contribute to the decarbonization of the transportation sector. These vehicles have no tailpipe emissions and can be quickly refueled with a hydrogen fuel cell. As the energy density of compressed hydrogen is higher than a comparable battery system, FCEVs are a viable option for transport market applications that require the capability to refuel quickly and have longer range, higher payload, and more cargo volume.

3.1.2.1.3.3 Industrial Fuel

Low-carbon hydrogen can serve as a source of decarbonized heat in industrial processes, especially in high-temperature heating applications which are difficult to electrify. In this use case, hydrogen could essentially be considered a direct replacement for natural gas.

3.1.2.1.3.4 Fuel for Residential and Commercial Buildings

Taking advantage of existing natural gas piping in homes and businesses, blending low-carbon hydrogen with natural gas can help decarbonize the building sector with minimal or no end-use appliance upgrades. Although direct combustion of hydrogen is possible, this would likely be considered a longer-term solution as appliances and infrastructure would either need to be modified or replaced.

3.1.2.1.3.5 Feedstock for Industry

Hydrogen currently serves as a feedstock in industrial processes, such as in the production of ammonia (NH_3) and methanol (CH_3OH); these processes could convert to using renewable hydrogen over time. There are additional emerging applications with long-term implications, including use as a reducing agent in steel production and an input to developing low-carbon liquid fuels for use in the aviation and marine industries.

3.1.2.2 Carbon Dioxide as a Feedstock

In an energy system where hydrocarbons are still utilized as fuels, "recycling" CO_2 as a feedstock for synthetic fuel production is a viable method for maintaining a carbon-neutral process. CO_2 can be sourced either through point source emissions (i.e. CCUS) or through atmospheric capture.

CCUS. As discussed in Section 3.1.1.3.1, CO_2 can be further utilized in lieu of permanently sequestering the gas underground. This method has the advantage of being a large and concentrated source, enabling synthetic fuel production at scale. One potential downside is that the CO_2 would need to be transported to the point of production (if not located at the storage location), eroding the economic case. There may be locations where green hydrogen production could occur co-located with a power plant CCS facility, making this scenario a viable long-term option.

Atmospheric Capture. As an alternative to the capture of point source emissions, CO_2 can be captured from the atmosphere – either through Direct Air Capture (DAC) or Indirect Ocean Capture (IOC). While the technology to remove CO_2 from the atmosphere is not new (the principles are similar to carbon capture from combustion exhaust), the process is energy intensive as CO_2 only makes up 0.04% of the earth's atmosphere and thus a large amount of air needs to be processed per unit of CO_2 extracted (*Mackenzie*, 1995). Despite the challenges, DAC has gained interest from the venture capital community with companies such as Climeworks and Carbon Engineering closing major investment rounds (*Carbon Engineering*, 2019; *Reuters*, 2020). Carbon capture from the ocean is also possible because CO_2 is in equilibrium with the atmosphere and dissolves into water as carbonic acid (*NOAA*, 2020). There has been some research interest in IOC, although these methods appear further from commercialization. One such example is a project at the Naval Research Laboratory (NRL) to develop a module which simultaneously produces hydrogen and extracts CO_2 from seawater. Currently undergoing testing at a laboratory scale, the end goal is to use seawater to produce jet fuel on aircraft carriers (*Willauer et al.*, 2017).

3.1.2.3 Renewable Fuels for Electricity Production

Clean synthetic fuels can be used for utility-scale electricity production in a carbon-free energy system. The three fuels we discuss in the following sections – hydrogen, methane, and methanol – are all "simple" chemical compounds with a low molecular weight. Complex hydrocarbons can be synthetically produced as well and could be a direct replacement for refined oil products in the transportation and industrial sectors.

3.1.2.3.1 Hydrogen Gas

The use of hydrogen on the grid represents an interesting opportunity for the utilization of existing power plants that could otherwise become stranded assets. The Los Angeles Department of Water and Power (LADWP) is planning to convert a Utah power plant from coal to natural gas, which will be capable of running on 100% hydrogen by 2045 (*Morehouse*, 2019). The Intermountain Power Plant, owned by the Intermountain Power Agency, would be the first power plant in the world to run on 100% green hydrogen and will connect to California through a high voltage direct-current (HVDC) transmission line. The hydrogen that is produced will be stored in an underground salt dome on site (*Power Engineering*, 2020). The gas turbines, produced by MHPS, will initially be able to run from a mixture of natural gas and hydrogen, and eventually will be modified to work with hydrogen alone. The project is being driven by California's mandate to have 100% carbon-free electricity by 2045 and the recent decision to close the remaining nuclear power plants in the state.

3.1.2.3.2 Methane

Methanation (also known as methane synthesis or the Sabatier process) is a chemical reaction between hydrogen and CO_2 that, in the presence of a catalyst, produces methane and water *(Seemann*

& Thunman, 2019). As the primary constituent of natural gas, methane is considered a direct substitute for natural gas and is thus the primary driver for its production.

The Southern California Gas Company (SoCalGas) has been on the front lines of experimenting with renewable methane production. They are engaged with multiple pilot projects, including one in collaboration with NREL to produce methane in a bioreactor (*Hicks*, 2017). Electrochaea supplies the bioreactor, which utilizes a proprietary process where a type of archaea microorganism converts hydrogen and CO_2 to methane. While this particular project is still at a pilot scale, Electrochaea does not believe there are any limitations to scaling the process.

3.1.2.3.3 Methanol

Methanol, also known as methyl alcohol, is a commodity primarily used as a feedstock for chemical production and is seeing increased adoption as a transportation fuel. The clean-burning fuel can also be used in a power plant for electricity production, significantly reducing pollutant emissions as compared to burning diesel or fuel oils (*Methanex*, n.d.). In 2014, the Israel Electric Corporation converted a diesel-powered gas turbine to run on methanol, reducing nitrogen oxide emissions by 80% (*Udasin*, 2014).

Methanol does not exist naturally in large quantities and must be produced from other compounds. While it typically is created from natural gas, green methanol can be created through a catalytic conversion process with hydrogen and CO_2. Carbon Recycling International, an Icelandic company, is dedicated to green methanol production, offers a commercial-scale plant design to customers, and is involved in several European projects.

3.1.3 Nuclear

Conventional nuclear power plants employ mature technologies that provide reliable, carbon-free electricity to the grid. Heat from uranium fission is used to generate steam, driving electric turbines and other auxiliary loads. Nuclear plants have traditionally been thought of as providing “baseload” to the grid operator since they are most efficiently operated at high power levels. The nuclear industry has suffered in the U.S. due to high costs, uncertainty around safety and radioactive waste disposal, and negative public perception. This has led to new construction project cancellations and plant closings prior to end-of-life. In order to support an advanced energy economy, the next generation of reactors are being developed to provide a more economical, safe, and flexible power source as compared to the large-scale reactors in commercial use today.

3.1.3.1 Reactor Types

Various reactor designs around the world are being considered for commercialization that have improved cost performance (capital and operating costs), flexible operation, safety features, and waste management. Some terms used in this paper, such as small modular reactors or advanced reactors, are not standardized in research. In general, the reactor types discussed here could provide important advantages compared with those currently operating on the grid around the world. Existing reactors, while representing a major source of carbon-free electricity, are likely not flexible or cost-effective enough to provide variable output or peaking capacity in a grid with high penetrations of wind and solar generation.

3.1.3.1.1 Small Modular Reactors (SMR)

There is strong interest in smaller and simpler reactor designs for generating electricity and process heat, driven by a desire to reduce capital costs and provide power away from large, centralized grid systems. When manufactured using modular construction techniques, which provides significant cost advantages, these reactors are typically referred to as small modular reactors (SMRs).

According to the World Nuclear Association (*WNA*, 2020b), there are several common features of an SMR:

- Small power (<700 MW)[6] and compact architecture with passive safety systems (less reliance on active safety systems as well as AC power for accident mitigation)
- Modularity of fabrication (in-factory) and transportable from factory to field; ability to have multiple units on site
- Lower radioactivity levels of waste and high proliferation resistance
- Potential for sub-grade (underground or underwater) location, providing more protection from natural or manmade hazards
- Lower requirement for access to cooling water (useful for remote, decentralized grid applications)
- Simple decommissioning process at end-of-life

There are several SMRs already operating or under construction around the world, predominantly in China, Russia, and India. About a dozen other designs are in an advanced stage of development, including four in the United States.

The reactor closest to regulatory approval in the U.S. is the NuScale SMR, whose design application is expected to be approved by the Nuclear Regulatory Commission (NRC) by the end of 2020 (*NRC*, n.d.-a). NuScale has defined a path to commercialization by launching the Western Initiative for Nuclear (Program WIN), a broad collaboration to deploy a series of SMRs in six Western states. The first utility-scale project will be built through a cost-sharing agreement with DOE for Utah Associated Municipal Power Systems (UAMPS) at the site of Idaho National Labs (INL). Known as the Carbon Free Power Project (CFPP), the 12-module 600 MW plant is expected to be fully operational by 2027 (*NuScale*, n.d.-a). NuScale is estimating its overnight capital cost at ~$5000/kW and targeting a LCOE of $65/MWh (*NEI*, 2018), which represents an improvement over existing nuclear facilities and could be competitive with other clean dispatchable power sources in certain markets.

Another SMR design, the BWRX-300 by GE Hitachi Nuclear Energy (GEH), is being supported by Dominion Energy with funding for design work (*GEH*, 2018). The BWRX-300 is a 300 MW plant and leverages the design and licensing basis of the NRC-certified Economic Simplified Boiling Water Reactor (ESBWR). The ESBWR is an existing-generation plant design (GEH refers to it as Generation III+) that employs simplicity in design and extensive passive safety features. The reactor can safely cool itself with no AC electrical power or human action for more than seven days, which addresses the root cause of the Fukushima nuclear disaster in Japan. GEH touts that the ESBWR is projected to have the lowest operating, maintenance, and staffing costs per MWh of any reactor technology today (*GEH*, n.d.-a). Dominion chose the ESBWR to be built as an additional unit at its existing North Anna nuclear site but in 2017 paused all development efforts due to a challenging economic environment for nuclear, ballooning construction costs, and public pressure (*Pierobon*, 2017). At about one fifth of the size, the BWRX-300 is essentially a smaller version of the ESBWR with design simplifications that GEH estimates will require up to 60% less capital cost per MW when compared to other water-cooled SMRs or existing large nuclear reactor designs.

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[6] The International Atomic Energy Agency (IAEA) considers reactors with <300 MW as 'small' and 300-700 MW as 'medium' sized. In this report, we consider any reactor <700 MW as small as they are smaller than the traditional utility-scale nuclear generating facilities.

3.1.3.1.2 Advanced Reactors

Advanced (or Generation IV) reactors have major architectural differences from plants currently in operation (Generation II/III) and represent advances in sustainability, economics, safety, reliability and proliferation-resistance. Advanced reactors typically use a different type of fuel, use coolants other than water, and operate at higher temperatures than current designs. Some of the reactors are designed specifically for electricity production while others are designed for multiple applications (electricity, hydrogen production, industrial heat, and/or desalination). An international task force is sharing R&D to develop six advanced reactor technologies for deployment between 2020 and 2030 (*WNA*, 2019).

Many advanced reactor designs only exist on paper or have been developed only for research use. Aside from technical considerations, these reactors face a more challenging path towards regulatory approval in the United States. The NRC has responded to commercial interest in the next generation of reactor designs and published a strategy in 2016 that addresses readiness to review and regulate non-light water reactors (LWR)[7] effectively and efficiently (*NRC*, 2016). The agency provided an update on the advanced reactor program status in January 2020 that identified specific activities that will be accomplished over the next 10+ years to support the initiative (Nieh, 2020). Perhaps most critically, they created a new Division of Advanced Reactors with the intent to provide increased focus on advanced reactors readiness activities and increased staff capacity to support the licensing of new designs. Although there is more work to be done, there appears to be a viable regulatory roadmap to bring advanced reactors to the marketplace over the next decade.

Advances in nuclear fuel development are also contributing to a resurgence in advanced reactor designs. Uranium that is mined must be enriched to a higher concentration of Uranium-235 for use as a reactor fuel. Uranium-235 (or U-235) is a specific isotope of uranium with a molecular weight of 235. This isotope is considered the “fuel” of most nuclear reactors[8] since it fissions (splits into two) when it absorbs a neutron in a nuclear reaction, producing heat which is then converted into electricity. Existing commercial reactors in the U.S. use low-enriched uranium (up to 5% U-235). Most advanced reactors plan to use what is known as High-Assay Low-Enriched Uranium (HALEU) fuel that is enriched to between 5 and 20%. This will allow for smaller designs, longer life cores, increased fuel efficiency, and less waste (*DOE*, n.d.-d).

Fuel can be loaded into a reactor core in many ways. For certain reactor types, fuel can be manufactured into small “particles” – a fuel kernel made of a uranium compound that is coated with structural materials. One type of fuel that is undergoing an extensive R&D and licensing program is known as a Tri-structural Isotopic (TRISO) particle (*DOE*, 2019a). These particles are about the size of a poppy seed and can withstand extreme temperatures well beyond the threshold of current nuclear fuels. Each particle acts as its own containment system as the fuel kernel is encapsulated by three layers of carbon- and ceramic-based materials that prevent the release of radioactive fission products. Although TRISO fuel was first developed in the 1960s, there is a resurgence of activity within the DOE and private industry to improve the fuel and several reactor developers have chosen to use TRISO fuel in their designs.

The NRC categorizes advanced reactors into four categories:

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[7] Light water refers to naturally existing water, while heavy water (deuterium oxide) contains a large proportion of molecules where the hydrogen atoms contain both a proton and a neutron. Heavy water has similar physical characteristics to light water but has certain desirable traits as a moderator in nuclear reactors.

[8] There are other isotopes of heavy elements that fission, such as Uranium-233 and Plutonium-239. A review of all possible nuclear fuel types is excluded from this report.

- Liquid Metal Cooled Fast Reactors (LMFR)
- High-Temperature Gas-Cooled Reactors (HTGR)
- Molten Salt Reactors (MSR)
- Microreactors

Appendix B provides a summary of each advanced reactor type.

3.1.3.2 Reactor Characteristics for a Resilient Grid

3.1.3.2.1 High Capacity Factors

Nuclear power operates at the highest capacity factors for utility scale generators using non-fossil fuel sources. At 94% capacity factor during 2019, nuclear exceeds geothermal (74%), biomass (59%), hydroelectric (39%), wind (35%), and solar photovoltaic (25%) (*EIA*, 2020a). Nuclear plants are typically operated at 100% of rated power with scheduled downtime for maintenance and refueling. This "baseload" characteristic is suitable for providing a stable electricity source in a grid with a high proportion of intermittent generation sources.

3.1.3.2.2 Variable Power Output

Due to the high costs of initiating or curtailing power output from conventional nuclear facilities, these plants have traditionally been used as a source of base load by grid operators. Future reactor designs will build in features to allow variable operation at a lower cost, making them more suitable in a peaking capacity. For example, the NuScale SMR is designed with load following features in mind (*NuScale*, n.d.-b):

- Dispatchable modules: One or more reactor modules (the NuScale design can include up to 12) can be taken offline for an indefinite amount of time. When refueling is required, only one module needs to be shut down at any time.
- Power maneuverability: Reactor power is easily adjusted over a period of minutes or longer.
- Turbine bypass: Turbine generator steam to the condenser may be bypassed over a period of seconds/minutes/hours.

In addition to these types of load following features, some reactors are designed to be refueled while operating. The X-energy Xe-100 reactor is designed for online refueling and X-energy claims a 95% plant availability rate. By introducing these features into future designs, nuclear plants will offer grid operators maximum flexibility and could serve a similar role to natural gas in the existing grid.

3.1.3.3 The Future of Nuclear Energy

Civil nuclear power has suffered from widespread negative public perception throughout its history, particularly due to three reactor accidents – Chernobyl, Three Mile Island, and Fukushima. This perception is one of the major barriers to wider adoption in a 100% clean electricity grid. Disposal of high-level radioactive waste is also a critical issue as there remains no permanent repository for nuclear waste in the United States (*GAO*, 2018). If nuclear power is going to be embraced as part of the solution to climate change, future reactor designs must provide passive safety features (i.e. eliminating the possibility of a major reactor accident through design) and should minimize the generation of long-lived radioactive waste. While each reactor type has certain advantages and disadvantages, all SMR and advanced reactor designs reviewed address these issues to some extent. As conventional reactors are retired over the coming decades, replacing this carbon-free generation capacity with safer, more flexible, and lower cost SMR and advanced reactor designs could be a viable option.

3.1.4 Biomass

Plant biomass is considered a renewable resource because it can be regrown on relatively short timescales, although there is substantial debate as to whether biomass (without CCS) can be considered a net zero carbon energy source. Wood-burning power plants and other biomass comprised roughly 4% of Virginia's power generation (*EIA*, 2020b). The majority of the current biomass power in Virginia has been developed by Dominion since 2010, with three old, uneconomic coal plants repurposed to run on 100% woody biomass and a new co-fired coal and biomass facility called the Virginia City Hybrid Energy Center starting operations in 2012 (*NRDC*, 2018).

The VCEA specifically names biomass (including the portion of a fossil plant co-fired with biomass) as a renewable resource for purposes of the RPS requirements, although there are significant restrictions on how much biomass is able to qualify after the first few years of the RPS (including a requirement that all biomass facilities that are not co-fired with coal be retired by 2028) (*Williams Mullen*, 2020). Such restrictions would need to be revisited for biomass to play an expanded role in a low-carbon grid in Virginia.

3.1.4.1 Feedstocks

Biomass feedstocks are diverse, with chemical compositions that vary significantly depending on the plant species. Common classifications identified by IRENA include agricultural residues (e.g. corn stalks, sugarcane, wheat straw), herbaceous crops (e.g. miscanthus, switchgrass), woody crops (e.g. pine, willow), forest residues, and urban residues. Moisture content, which can vary from 10-60%, has a negative effect on energy value, which increases transportation and fuel cost per unit of energy. Ash content (more common in grasses, bark and field crop residues and less common in wood) can cause problems by forming deposits inside combustion equipment. Size and density of the feedstock affects the rate of heating and drying, affecting the types of handling equipment and processing required (*IRENA*, 2012). Forest residues and wood waste are generally the cheapest feedstocks and are widely available in Virginia, while agricultural residues are also relatively cheap and abundant in Virginia. A 2014 report prepared for Virginia's Department of Mines, Minerals and Energy (DMME) estimated there are over seven million metric tons of forest residues, primary and secondary mill residues, urban wood waste and crop residues available annually statewide (Becker, n.d.). All of the existing biomass facilities in Virginia are powered by wood waste from timber logging. Energy crops offer a more energy-dense alternative but are generally more expensive and entail land use tradeoffs.

3.1.4.2 Conversion and Generation Technologies

Biomass can be converted into energy using a variety of thermo-chemical (combustion, gasification, and pyrolysis) and bio-chemical (anaerobic digestion) processes. Combustion is by far the most common process used today, where a traditional high-pressure boiler is used to generate steam. Gasification uses partial combustion to release a gas which in turn can be used in combustion engines, fuel cells or gas turbines. Pyrolysis is similar to gasification but halts combustion at a lower temperature to create a liquid bio-oil which can be used as a fuel to generate power. Anaerobic digestion was described in Section 3.1.1.3.2.1; raw biogas to power applications are not commonly used for utility-scale generation (*IRENA*, 2012).

3.1.4.3 Economics and Outlook

According to NREL, biomass power generation is roughly 3x more expensive than today's natural gas generation technologies (*NREL*, 2019). A Natural Resources Defense Council (NRDC) briefing cites research from Georgia Tech specifically analyzing Dominion's fleet of biomass plants that confirms LCOEs in this same range ($94-147/MWh) (*NRDC*, 2018). And according to IRENA, although the potential for cost reductions in biomass is difficult to assess due to the range of potential technologies and feedstocks available, "there is currently little discussion about learning curves for biomass power generation." This is in part because "the main question regarding the viability of biomass…lies in the development of a reliable feedstock supply chain." IRENA's conclusion is that cost reductions greater than 2-25% (from 2012 levels) should not be expected (*IRENA*, 2012).

Robust regional biomass supply chains are not out of the question for Virginia, particularly considering the fact that they already supply roughly 4% of the Commonwealth's electricity production (*EIA*, 2020b). Although the cost of generation is high on the current supply curve, it is certainly possible that such a cost position will be competitive when compared with energy storage technologies or an expensive overbuild of wind and solar to achieve the last few percentage points of renewable power on the grid.

3.1.4.4 The Zero Carbon Debate and the Importance of CCS

The restrictions placed on use of biomass beyond 2028 in Virginia's clean energy legislation reflects a broader debate around the environmental footprint of biomass production. Harvesting, transporting, and processing the feedstocks adds to the carbon footprint of the technology (until such activities can be made carbon neutral themselves). Depending on the feedstock, there are also challenges related to land use change, food systems, and impact on ecosystem services. In short, it is arguable that substantial use of biomass for energy production is, in fact, "sustainable."

At the same time, many in the international community have viewed biomass (or bioenergy more broadly, which includes fuels like RNG) combined with CCS as one of the most promising and commercially feasible approaches to achieve negative emissions technologies necessary to avoid the worst outcomes of global climate change. If carbon that has been sequestered by plant life is combusted to produce electricity and the resulting CO_2 is again sequestered, this would result in net negative CO_2 emissions. Although biomass is not without its sustainability critics, it does avoid the potentially significant issues of methane emissions in the natural gas supply chain. If Virginia's legislation were to be adjusted to include biomass in combination with CCS, this could also contribute to achieving net zero carbon goals for the Commonwealth.

In addition to land use concerns, a challenge for extensive use of biomass + CCS (or BECCS), is that it combines two comparatively costly technologies. According to Fuss et al., most cost estimates for BECCS begin with coal + CCS and assume the biomass feedstock is cheaper than coal. While the fuel cost alone may be less, biomass is more expensive per unit of energy due to its lower carbon content, higher moisture content, and increased cost of storage and handling (*Fuss et al.*, 2018). All of this means that BECCS could be on the order of 2x more expensive than natural gas with CCS, and it faces the same risks and uncertainties associated with CO_2 sequestration as any other technologies combined with CCS. A price on carbon that rewards potentially negative emissions technologies could help, but the carbon price would need to be significant for BECCS to be economically competitive with other options for achieving a 100% clean electric grid.

3.2 Long-Duration Storage

While some or all of the "clean dispatchable generation" technologies may play a role in a high renewables grid, they are not the only options available to solve the intermittency problem. Storage technologies can also "fill the gap" by storing energy during periods of oversupply by wind and solar and releasing energy during shortfalls in renewable production needed to meet demand. Energy storage is a wide category that includes energy carriers (such as hydrogen), batteries (including lithium-ion, flow batteries, and a host of other electrochemical configurations), mechanical systems (including gravity-based systems, compressed air, and flywheels) and other technologies. Energy can be stored for many purposes, including transportation and heating, but our focus is on its use for dispatchable electricity generation.

Energy storage can be used in a variety of ways in the electricity system. Schmidt et al. review 27 "unique-purpose electricity storage services" and allocate them to 12 "core applications" for storage technologies: energy arbitrage, primary response, secondary response, tertiary response, peaker replacement, black start, seasonal storage, transmission and distribution (T&D) upgrade deferral, congestion management, bill management, power quality, and power reliability (*Schmidt et al.*, 2019). The authors create profiles of the size (in MW), duration (in hours), cycles (# per year), and response time (in seconds) required to serve each application in order to assess the viability and cost of a variety of technologies for each application. While all of these applications are important to the electricity system, and energy storage technologies can and will play a role in all of them, Schmidt et al. conclude that one technology in particular is at a distinct advantage with regard to most of the applications and is unlikely to be surpassed by other technologies based on what we know today: lithium-ion batteries. Schmidt et al. also conclude (as is widely recognized in the industry) that lithium-ion batteries are not well-suited to longer-duration storage applications requiring 10+ hours of discharge (*Schmidt et al.*, 2019). A 2019 report from the Rocky Mountain institute reaches a similar conclusion (*Bloch et al.*, 2019):

> *"As storage requirements move beyond the four-hour threshold, technologies with lower duty-cycle degradation at full depth of discharge, lower material costs, and longer lifetimes will be better suited to provide those lower costs than what most analysts believe Li-ion can achieve."*

For this reason, our report focuses on "long-duration" storage technologies that may be necessary to enable a high renewables grid in light of the technical and cost limitations of overbuilding both renewable generation and shorter-duration storage. The long-duration "gaps" that need to be filled must be modeled for Virginia, but could stretch from diurnal periods (on particularly cloudy or windless days) to multiple days, weeks, or even months (based on seasonal weather patterns). We describe the leading technology solutions that would provide long duration energy storage. These include electrochemical (batteries), mechanical (gravity-based and compressed air), chemical (hydrogen), and thermal (cryogenic liquid air and molten salt) technologies.

3.2.1 Batteries

Electrochemical storage comprises a wide range of battery technologies that vary across critical technical and economics characteristics, including energy density, power density, discharge rate, response time, cost, and cycle life — among others. The basic principle of all battery technologies is the use of a chemical reaction to create a difference in electrical charge, which is the basis of the stored energy. When the battery is connected to a circuit and the difference in electrical charge is allowed to dissipate, electricity is produced. As this discharge occurs, the reactants in the battery are degraded and the system must be connected to an external power source to run the process in reverse and recharge the battery (by restoring its electrodes to their original state). The electrodes (positively charged cathode and negatively charged anode) and the electrolyte (medium for the flow of electrons) can be made from a variety of materials to deliver different battery properties. Because of their scalability and modularity, batteries are an incredibly flexible storage technology and are being deployed in applications ranging from kW-scale household use to GW-scale support for utility operations.

Perhaps the most critical characteristics for batteries to provide long-duration storage are a low self-discharge rate (low energy lost over time while awaiting dispatch), a long discharge duration, and costs that can compete with clean power generation operating at low capacity factors for which these batteries might be a reasonable substitute. A technical report from IRENA categorizes major battery technologies as lithium-ion, lead-acid, flow batteries, and high temperature batteries (*IRENA*, 2017b). We adopt this framework and briefly describe each technology, excluding lead-acid batteries as they have not been demonstrated to provide the long-duration storage capabilities that are the focus of our report. We include a discussion of lithium-ion batteries even though they are widely believed to be insufficient for long-duration storage. In order to understand the benefits, challenges, and path to commercial viability for the long-duration battery contenders, it is helpful to first understand the leading technology in the existing battery storage market.

3.2.1.1 Lithium-ion Batteries

Lithium ion (Li-ion) batteries include a range of battery chemistries all using the transfer of lithium compounds between electrodes. While Li-ion batteries are often discussed as a single technology, this is not the case. The various chemistries of Li-ion batteries yield unique performance, cost, and safety characteristics. The chemistry choice often relates to the desire to optimize the system to meet various performance or operational objectives; such considerations may lead to a different electrode or electrolyte material selection. For example, some Li-ion systems may be designed for applications where high power or high energy density is required (consumer electronics and electric vehicles), while for other applications prolonged life or the lowest capital cost possible may be the goal (utility-scale storage). As a group, Li-ion batteries have certain common advantages: high energy and power density, high-power discharge capability, very high roundtrip efficiency, a relatively long lifetime, and a low self-discharge rate (*IRENA*, 2017b).

Over the last decade, Li-ion battery pack prices have declined more than 80% due to technological improvements, increased manufacturing capacity, and the growing demands of the electric vehicle industry. According to the Rocky Mountain Institute, various battery technologies combined with renewable generation are now competitive with new natural gas plants and will soon be competitive with existing natural gas plants (*Bloch et al.*, 2019). For example, in April 2020, utility owner and developer NextEra Energy announced plans to spend $1 billion on energy storage projects in 2021, led by a 400+ MW facility in Florida to be powered by solar and used to replace a pair of aging natural gas plants (*Stromsta*, 2020a). In May 2020, utility group PacifiCorp announced a request for proposal that includes 595 MW of energy storage paired with solar, in lieu of building new natural gas peaking plants (*St. John*, 2020b). Also, in May 2020, utility Southern California Edison announced seven new contracts for 770 MW of battery storage capacity, primarily to be co-located with existing solar facilities to replace the retirement of four natural gas plants (*St. John*, 2020a). These new projects confirm recent estimates that the levelized cost ($/MWh) of solar paired with four-hour storage ($102-139) (*Lazard*, 2019b) is now competitive with natural gas peaking plants ($150-199) (*Lazard*, 2019a). For certain applications, Li-ion battery storage paired with renewables has become an economically viable alternative to traditional sources of generation across the country.

Li-ion batteries must still contend with several shortcomings. First, they face questions regarding safety after incidents like the April 2019 explosion at a major Arizona facility (*Spector*, 2019a). Second, the key materials (lithium and cobalt) must be mined in sensitive regions of the world and there is some debate around whether supply chain constraints could become a problem for the industry (*IRENA*, 2017b). And third, current configurations have been limited to supplying four hours of discharge, which is sufficient for many of the use cases of batteries in today's lower-renewables power grids, but is insufficient for the kinds of long-duration storage applications we envision in this report. Given projected cost declines and the possibility of improvements in energy density, it is possible that the role of Li-ion could be expanded to eight-hour applications or even further (*Bloch et al.*, 2019). But while Li-ion batteries are beginning to play a major role in the power sector around the world, other technologies may be needed to fill the gap in a higher-renewables grid.

3.2.1.2 Flow Batteries

According to IRENA, flow batteries can also be described as “regenerative fuel cells” and exist in a variety of forms. Whereas traditional rechargeable batteries store the reactive materials in the cell, flow batteries use dissolved electrolyte solutions stored in tanks separated from the regenerative cell stack. In “pure flow” batteries, all active materials are stored outside the cell (e.g. Vanadium redox or VRFB), while in “hybrid flow” batteries, one or more active materials are stored inside the cell (e.g. Zinc-bromide or ZBFB) (*IRENA*, 2017b).

Flow batteries have several key advantages relative to Li-ion. They can operate at near-ambient temperatures, their power (cell stack) and energy (tank volume) characteristics can be flexibly designed, they offer lifetimes greater than 10,000 full cycles, and they have better safety characteristics. Potential disadvantages include a higher cost of repair and maintenance given a greater number of moving parts and equipment and the need to manage fluid leaks (*IRENA*, 2017b).

We describe the two dominant designs within the “pure flow” and “hybrid flow” formats:

<u>Vanadium Redox (VRFB)</u> designs capitalize on the ability of vanadium to be present in four different oxidation states, which means only one active material is needed in the entire system, avoiding cross-tank contamination. “Redox” simply refers to reduction (the gain of electrons) and oxidation (the loss of electrons) which is characteristic of all battery systems. VRFB systems are capable of very long cycle life (10-20x 10,000 cycles), long duration (up to 20 hours continuous discharge), and quick response times (*IRENA*, 2017b). It is one of the most mature flow battery technologies, with several demonstration projects deployed at MW scale. For example, in April 2019 the California Independent System Operator (CAISO) announced a 2 MW / 8 MWh VRFB pilot project to provide 4-hour energy storage in the wholesale power market (*H. Mai*, 2019). The chief shortcoming is the high cost of vanadium and current membrane designs (*IRENA*, 2017b).

<u>Zinc-bromide (ZBFB)</u> designs operate similarly to VRFBs but use a different set of chemical reactions to generate the electrical energy. They have higher energy density than VRFBs, deep discharge capabilities, and abundant low-cost reactants (with the exception of certain bromine “complexing agents,” which can be expensive). However, ZBFB energy and power ratings are not as independently scalable as VRFB, they risk material corrosion, more auxiliary systems are required for temperature control, they experience very high self-discharge rates (8-33% per day), and cycle life is lower than VRFB. For these reasons, ZBFBs are not widely considered a primary candidate for scaled storage (*IRENA*, 2017b).

Pathways to cost declines for flow batteries include chemical stability of the electrolyte (to extend life), the cost of materials (cell stack, electrolyte, and active materials), and improved performance of membranes and other components. Studies have indicated a pathway to installed cost of VRFB at $120/kWh (near the DOE’s target for competitive storage systems at $100/kWh), but according to IRENA, the “actual least-cost pathway for flow systems remains a matter of considerable active debate” (*IRENA*, 2017b).

One of the leading commercial developers of flow batteries is Massachusetts-based Vionx in tandem with their lead equity investor, United Technologies Corporation. Vionx deploys a modular VRFB design touting a 20+ year life, up to 10 hours demonstrated discharge, and unlimited cycles. Vionx claims a total life cycle cost on both 4-hour and 8-hour applications that is cheaper than Li-ion. They have operated a pilot facility for the U.S. Army since 2015, a 3 MWh wind integration facility for National

Grid since 2017, and reportedly have solar integration and demand management facilities offering between 4- to 6-hour duration services scheduled for interconnection or commissioning in 2020 (*Vionx*, n.d.).

Another battery developer with commercial traction is Form Energy, a startup that has secured financing from Breakthrough Energy Ventures and Saudi Aramco. While Form has not provided substantial information on its technical approach, they have in the past conducted development work on an aqueous sulfur flow battery (*APRA-E*, 2018) and are now developing a so-called "aqueous air" battery. In general, the company is pursuing battery chemistries for long-term energy storage in excess of 100 hours. In May 2020, Minnesota utility Great River Energy confirmed a 1 MW, 150-hour pilot project with Form Energy designed to test its ability to pair with wind in order to replace aging coal assets (*Spector*, 2020b). This is a small first step, but it does suggest that a new ultra-long duration storage technology is approaching full commercial deployment.

3.2.1.3 High Temperature Batteries

High temperature batteries use liquid active materials that require significant heat to maintain a liquid state and are separated by a solid ceramic electrolyte. The anode material is typically molten sodium (Na). According to IRENA, the two most relevant commercial configurations are sodium-sulfur (NaS) and sodium nickel chloride (NaNiCl). NaS systems are more commercially mature, with over 300 MW across 170+ projects in Japan (*IRENA*, 2017b).

The benefits of NaS include relatively high energy density compared to flow batteries (near the low end of the range of Li-ion), low self-discharge rates, and a lifetime of ~5,000 cycles with demonstrated capability to go as high as 10,000. In addition, the materials are fully non-toxic and 99% recyclable (*IRENA*, 2017b).

The primary impediments to scale for NaS systems are corrosion issues and high operating costs associated with the additional thermal casing and other equipment required to operate at high temperatures. The corrosion problem requires the development of more robust materials, coatings, and joints. The high operating cost problem is the subject of ongoing innovation to reduce the operating temperature of these systems (e.g. by coating the electrolyte, replacing the electrolyte to enable an all-solid-state cell, etc.) With almost all NaS batteries currently manufactured by NGK Insulators Ltd. of Japan (*IRENA*, 2017b), the pace of innovation for NaS systems may not be as rapid as other battery technologies where there is more active competition and investment.

3.2.2 Gravity

One of the simplest and most well-known forces of physics—gravity—can be harnessed in multiple forms of energy storage. These technologies vary from the mature but highly site-dependent, to the demonstration scale but modular. A host of gravity-based storage solutions have been theorized over the last several decades and garnered renewed interest in recent years. We focus on the most proven technology (pumped hydro) and a more recent innovation (block towers).

3.2.2.1 Pumped Hydropower

Perhaps the most mature non-fuel energy storage technology is pumped hydropower (hydro) storage (PHS). PHS has a long history, high technical maturity, and large energy capacity. Nearly 1,300 GW of PHS capacity is operating globally, with almost 22 GW of capacity installed in 2018 (*IHA*, 2019). In fact, the largest PHS system in North America is majority owned by Dominion Energy and located in Bath County, VA. The Bath County Pumped Storage Station began operation in 1985 and has a net generating capacity of just over 3 GW (~10% of Virginia's total), with actual 2018 generation of ~8.6 GWh[9] (~9% of Virginia's total) (*Dominion*, n.d.; *EIA*, 2020b).

A typical PHS plant uses a simple, two reservoir system. During periods of low electricity demand, water is pumped to the higher reservoir; during periods of high electricity demand, water is released back to the lower reservoir, powering a turbine to generate electricity. The amount of energy stored is determined by the height difference between the reservoirs and the total volume of water. The rated power of the plant is determined by the water pressure and rate of flow through the turbine, as well as the power rating of the pumps, turbines, and generators used. PHS plants vary significantly in size, from 1 MW to the >3 GW Bath County facility. They average 70-85% efficiency and can operate for 40 years or longer (*Luo et al.*, 2015).

The greatest shortcoming of PHS plants is that they are entirely geography-dependent and therefore bespoke. Relatively few sites are suitable for such systems, and they are expensive to design and construct. As recently as July 2019, Dominion was actively studying a Tazewell County site in Southwest Virginia that could host a second major pumped storage facility. Dominion claimed this facility would bring over 2,000 jobs to an economically depressed coal mining region over the 10 year development and construction phase and deliver over $300 million in local economic benefits (*Dominion*, 2019b). This new proposed facility was enabled by 2017 legislation deeming additional pumped hydro "in the public interest" (meaning an easier regulatory path to approval if Dominion proceeds with the project) (*Maloney*, 2017). Criticism has been leveled over both the cost (estimates vary from $300 million to $2 billion) and environmental impact of the project (Shepherd & Shepherd, 2019). The replicability of PHS as a solution to the intermittency of a high-renewables grid may reasonably be doubted, but even if only the existing facilities continue operating, it will very likely play a role.

3.2.2.2 Block Towers

Using the same gravity-based principle as PHS, startup Energy Vault (co-founded by billionaire Bill Gross and incubated by Gross's Pasadena-based Idealab) unveiled a novel technology in 2018. Energy Vault has developed a system to use automated, 35-story cranes to lift thousands of 35-metric ton concrete blocks into a large tower. The system would use inexpensive electricity from renewables during periods of overproduction to run the cranes and "store" the blocks' potential energy, quickly lowering the blocks to run generators and produce electricity during periods of underproduction from renewables. Energy Vault claims that a fully scaled system would be sized at 4 MW/35 MWh (nearly nine hours of discharge at full capacity), would achieve 90% round-trip efficiency, and would require 50% of the capital cost and 80% of the levelized cost of existing storage technologies. And all of this can theoretically be achieved without the thorny siting challenges and decade-long development cycles associated with PHS (*Spector*, 2018b).

As part of Energy Vault's "unstealthing" in November 2018, they announced a Switzerland-based demonstration project at one seventh scale. They also announced Tata Power Company would be the first (public) customer, with a full-scale project scheduled to be built in 2019 (*Spector*, 2018b). In August 2019, Energy Vault announced a $110 million investment from Japan's Softbank Vision Fund to drive the technology to commercial scale. Partnerships have also been executed with Cemex (to develop cheap materials for the blocks), General Electric (for the motors), and a crane manufacturer—

[9] EIA reports net negative generation for the Bath County station because pumped hydro facilities require more power to store energy than the energy they generate when discharged. We applied an 85% efficiency assumption to the EIA reported net generation in order to estimate the gross generation of the facility, which equates to a ~33% capacity factor.

all of which will enable Energy Vault to deploy projects without their own manufacturing facilities (*St. John*, 2019).

Energy Vault's technology appears promising and major investors are lined up in support, but some skepticism is still warranted. Startups with bold claims about "simple" physical storage technologies and major investors are nothing new to observers of the energy storage industry. Another gravity-based storage startup called Energy Cache out of Gross's Idealab tried a ski lift to carry weights up an incline in 2012. Energy Cache couldn't scale beyond a 5 kW demonstration project, and the founder is now with Energy Vault (*Spector*, 2018b). As of May 2020, there was no public news of Energy Vault's full-scale project for Tata. Further information on demonstration projects and commercial deployment is needed to determine if Energy Vault's claims are warranted.

3.2.3 Compressed Air

Compressed air energy storage (or CAES) is a relatively mature technology (although far less widely deployed than PHS) with traditional applications that are generally geography dependent. The two existing utility-scale CAES facilities in the world began operations in the 1970s (the 290 MW Huntorf plant in Germany) and 1990s (the 110 MW McIntosh, Alabama plant in the US)—both of which use natural salt caverns for storage and have demonstrated starting and running reliability in excess of 90% (*Luo et al.*, 2015).

During periods of low power demand, excess electricity drives a reversible motor/generator to run a series of compressors which inject high-pressure air into a storage vessel, either underground or in above-ground tanks. During periods of high power demand or shortfalls in renewable generation, the stored air is released and heated to drive a turbine and generate electricity. The Huntorf and McIntosh plants use fossil fuels to generate the heat needed for this final step, but the process can be engineered to recover and reuse heat from compression using solids like concrete or stone, or potentially liquids such as hot oil or molten salt, which has a dual benefit of removing the need for fossil fuels and increasing cycle efficiencies closer to the level of PHS and batteries (*Budt et al.*, 2016; *Luo et al.*, 2015).

The major barrier to CAES deployment is the geology-dependence of siting. The type of salt caverns used at Huntorf and McIntosh are not widely occurring in nature, and the use of other formations more relevant to Virginia like offshore saline aquifers, rock caverns, or abandoned mine infrastructure are still being studied (*Budt et al.*, 2016). Significant development is ongoing with regard to process improvements, novel storage vessels (both natural and man-made), and potentially modular applications, but no applications have exited the research or demonstration phase.

A novel, more geographically flexible CAES technology is being developed by Canada-based startup Hydrostor. This system uses widely available mining industry equipment, custom-built tunnel shafts and storage caverns, a water-based pressure regulation system that reduces the required size of the storage cavity, and fuel-free thermal storage to capture and reuse the heat from compression during generation. In February 2019, Hydrostor announced a $9 million, 5 MW demonstration-scale project in South Australia sited at an abandoned coal mine (*Hydrostor*, 2019). In September 2019, they announced a $37 million growth financing and an equipment partnership with energy giant Baker Hughes (*GlobeNewswire*, 2019), and in November 2019, they announced the successful completion and initial operations of a ~2 MW project in Ontario. In 2019, Hydrostor was also reported to be bidding on multiple 300-500 MW projects in North America (*Rathi*, 2019).

As discussed with Energy Vault, Hydrostor's progress may be reasonably viewed with skepticism until proven at larger scale. LightSail (*Spector*, 2017), SustainX (*St. John*, 2015), and General Compression

(*Rathi*, 2019) were all promising startups working on various forms of containerized or underground compressed air technologies over the last 5-10 years, but none seem to have advanced to large scale commercial operation. If Hydrostor is able to demonstrate its approach is technically and economically viable at scale, it could be an attractive option for the coal mining regions of Southwest Virginia.

3.2.4 Hydrogen

As detailed in Section 3.1.2.1, hydrogen is a versatile energy carrier and can be considered a feedstock for synthetic fuels for electricity production. In addition to its role in power generation, hydrogen can also be considered a form of long-duration energy storage. As intermittent renewables are added to the grid, a scenario where producing hydrogen from renewable production that would otherwise be curtailed becomes increasingly realistic. As more renewables continue to be deployed, the economics and utility of green hydrogen can be expected to continue to improve and it could reasonably become a widely used means of long-duration energy storage for grid applications.

3.2.5 Thermal

Thermal energy storage (TES) describes a range of methods to store heat energy in contained environments. Electricity is used to generate the heat and pass it to a storage medium during periods of low power demand. Then during periods of high power demand, the stored heat is passed back from the storage medium through a heat exchanger to turn a turbine to generate electricity. Luo et al. categorize TES into low-temperature (e.g. cryogenic storage of liquid air) and high-temperature approaches (e.g. molten salt heated by concentrated solar power).

3.2.5.1 Low-Temperature

One promising method of low-temperature TES uses compressors to cool air to cryogenic temperatures (-196°C) and store it in above-ground, low-pressure insulated tanks as a liquid. When power is needed, the air is released and naturally expands (without combustion) to turn a turbine and generate electricity. UK-based Highview Power—the patent-holder and developer of this technology—has been testing the approach for over 10 years and has made material commercial progress within the last two years. After operating a 350 kW pilot facility in 2011-2014, Highview began operations at a 5 MW demonstration-scale facility near Manchester in June 2018 (*Spector*, 2018a), and in October 2019 announced development of a 50 MW utility-scale project to be completed in 2022, also in the UK (*Spector*, 2019b). A $46 million equity financing from Sumitomo Heavy Industries completed in the first quarter of 2020 provided a key industrial partner to scale the technology (*Spector*, 2020a).

If Highview's commercial progress proves the technology at scale, liquid air presents compelling benefits as a contender for long-duration storage (as well as other energy storage applications). The facilities leverage mature components and supply chains from the oil and gas industry, can be sited almost anywhere, and can be built at GW-scale. The efficiency is a modest 60% (70% if paired with industrial applications from which waste heat or cold can be utilized), but its scale and long life without equipment degradation offset concerns of low efficiency. Highview's CEO promises costs that are in line with flexible natural gas plants or renewables paired with batteries (*Highview Power*, n.d.), but commercial validation is needed.

3.2.5.2 High-Temperature

The most commercially mature form of TES is a high-temperature approach: turning concentrated solar power (CSP) plants into dispatchable facilities using molten salt to store the solar energy. According to IRENA, TES represented over 3 GW of operational capacity globally in 2017 (second only to PHS among energy storage technologies), and three quarters of the TES deployments utilize molten salt as the heat transfer fluid. The majority of CSP + molten salt facilities today are located in Spain and the United

States, with most use cases dedicated to “firming” (making more continuously available) the capacity of renewables (*IRENA*, 2017b).

CSP + molten salt facilities comprise a field of reflectors concentrating light onto a receiver, which gathers heat and transfers it to molten salt as the storage medium or “heat transfer fluid”, which is then stored and transferred to a steam generator to produce electricity when needed. Receivers can be integrated with reflectors (e.g. in a parabolic trough configuration) or standalone (e.g. in a solar tower)—although solar towers are more promising and can reach the largest scale (250 MW). While CSP + molten salt plants are primarily configured as baseload plants (the stored energy generates power while the sun is down), they can be configured to provide a variety of grid services depending on compensation models and specific needs in the local grid (*Bielecki et al.*, 2019). The geographic suitability for CSP (high solar irradiance is necessary and therefore most appropriate in the U.S. Southwest) is the largest obstacle for deployment in Virginia (*SEIA*, n.d.).

On the horizon is the Cambridge, Massachusetts-based startup Malta, which was incubated in Alphabet’s “X” moonshot lab (formerly Google X) and raised a $26 million Series A funding round in 2019 led by Breakthrough Energy Ventures. Malta is developing a 10 MW pilot plant (location not yet announced) to demonstrate its novel thermal storage technology, which uses two molten salt tanks and two cold refrigerant tanks in combination to operate a standalone heat pump-based generator. The deployment of Malta’s solution should be watched carefully, as it could present another opportunity for scalable, standalone, long-duration storage without reliance on geology or geography (*Clancy*, 2019).

4 TECHNOLOGY ASSESSMENTS

Based on this review of key aspects of commercially available and emerging technologies, we assess them relative to key characteristics that will inform which technology or suite of technologies holds the most promise for Virginia's future 100% clean electric grid. First, we assess the technologies relative to certain qualitative characteristics and identify the critical hurdles for each technology to be viable. Second, we assess the current and projected cost of each technology to the extent such information is available in the literature, while noting the particular challenges of assessing economic performance using simple levelized cost metrics.

4.1 Qualitative Assessments

We rate each technology on a scale from 1 to 4 for each of the following criteria:

- **Technical Readiness:** Capable of transitioning from an R&D stage to implementation on the grid on a timescale out to 2030.[10]
- **Scalability:** The ability for projects to grow to utility-scale (often defined as 10 MW or above) and be integrated with the grid.
- **Reliability:** The extent to which a power source will be safely and immediately available when it is "dispatched".
- **Flexibility:** The ability of the power source to respond to dynamic electric load profiles as necessary for the grid operator.
- **Environmental Rating:** An assessment of environmental impact (e.g. lifecycle greenhouse gas emissions, mining, water use, land use, air and water pollution, etc.) To be clear, a higher rating indicates the technology is considered more environmentally "friendly".
- **Applicability to Virginia:** An assessment as to whether the technology could be implemented at meaningful scale within the Commonwealth of Virginia based on various considerations (geography, weather, industrial and agricultural considerations, etc.)

In addition, we summarize the critical hurdles each technology must address in order to be viable. These hurdles have been broadly categorized and identified with a letter as follows:

- T = Additional development of transportation infrastructure is needed
- S = Additional development of storage infrastructure is needed
- U = Additional development of utilization cases is needed
- M = Market reforms are needed
- C = Commercial deployment is needed
- B = Basic technology improvements are needed
- E = Environmental concerns must be better understood, e.g. through Life Cycle Assessment
- L = Land restrictions must be overcome or better understood

We summarize the ratings for all technologies in Table 1 with greater shading of the Harvey Balls indicating higher ratings. Supporting detail and rationale for the ratings is contained in Appendix A. It should be noted that these ratings are from the authors' perspective based on our assessment of the literature, and we expect them to be challenged and questioned as part of a broader effort to determine how best to achieve Virginia's clean energy goals.

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[10] Note that while this assessment does not explicitly consider economic viability, many technologies will not transition from the R&D stage if there is seemingly no path towards economic competitiveness relative to other clean energy alternatives.

Table 1: Summary of all technology assessments

Criteria	Technical Readiness	Scalability	Reliability	Flexibility	Env. Rating	Appl. to VA	Critical Hurdles
Natural Gas w/ CCS	2	2	4	4	1	2	**T S U C E**
Renewable Natural Gas	3	2	4	4	3	4	**M C E**
Synthetic Fuels	3	2	4	4	2	3	**T S M B C E**
Allam Cycle	1	2	4	4	2	2	**T S U B C E**
Advanced Nuclear	3	3	3	4	2	4	**M C**
Biomass w/ CCS	2	1	4	4	2	2	**T S U C E**
Li-Ion Batteries	4	3	3	4	2	4	**M B C E**
Flow Batteries	2	4	3	4	3	4	**M B C E**
High Temperature Batteries	2	3	2	4	4	4	**M B C**
Pumped Hydro	4	1	4	3	2	4	**E L**
Block Towers	1	3	2	4	3	4	**C E**
Compressed Air Energy Storage	1	2	3	3	3	2	**S B C L**
Hydrogen	3	4	3	4	4	3	**S C**
Low Temperature Thermal Storage	1	4	3	3	4	4	**B C**
High Temperature Thermal Storage	4	2	4	2	4	1	**L**

4.2 Economic Assessments

In addition to the assessment of key qualitative factors previously discussed, it is important to understand the relative economic cost associated with each clean dispatchable generation and long-duration storage technology. A comparison of costs is notoriously difficult because of the unique characteristics and proposed operating profiles of each technology. Ideally, a dynamic model of the electricity system should be constructed with detailed assumptions regarding the physical and economic characteristics of the possible generation and storage technologies, the physical parameters of the grid, and granular projections of daily and seasonal load profiles. Stochastic grid models of this type have been deployed across academic, state policy, and consulting settings and are becoming more common—including increased availability of open-source modeling tools.

In the absence of such a detailed model, some indication for the potential contribution of individual technologies can be derived from static metrics such as the "levelized cost of electricity" (or LCOE). A LCOE metric estimates the total cost associated with construction, operation and financing of a representative project and divides by the total electricity produced over the project's lifetime to arrive at a cost per unit energy (e.g. MWh) that can be compared across technologies. A similar set of metrics is available for energy storage technologies and is referred to as the "levelized cost of storage" (or LCOS). Commonly referenced analyses of the LCOE of various technologies are produced by Lazard (*Lazard*, 2019a) and NREL (*NREL*, 2019), and similar calculations are often included in academic papers. Given the increasing prevalence of lithium-ion batteries for grid-scale energy storage applications in recent years, Lazard has also begun publishing an annual LCOS report (*Lazard*, 2019b) alongside its LCOE report, and similar LCOS approaches have appeared in recent academic papers, including a useful report by Schmidt et al. (*Schmidt et al.*, 2019) which goes beyond lithium-ion to examine the LCOS for many of the long-duration storage candidates discussed in this report.

LCOE and LCOS calculations are helpful but imperfect tools for understanding the role of various technologies in a low-cost, reliable electricity system (*Jenkins*, 2020). First, these calculations are often applied inconsistently (e.g. Researcher A's LCOE definition may differ from Consultant B's definition), using different assumptions or including/excluding different costs. Second, an LCOE calculation cannot fully consider the marginal value of adding a resource to an electricity system. For example, a variable generation resource like solar provides significant value to the grid at low cost when there is not much solar already built (so that every MWh produced is consumed). But as more solar is added to the grid, production is not fully aligned with demand and value is lost either by curtailment from overproduction or shortfalls that must be supplied from other generation resources. Similarly, as storage is added to the grid, it can be used very effectively to "smooth" relatively brief periods of overproduction or shortfalls, but as much more storage is added, a point may be reached where each marginal MW of storage will be needed less frequently than the previous one and the marginal cost per MWh of use will therefore increase. For these reasons, "cheap" renewables and shorter-duration storage that is becoming "cheaper" also face falling marginal value curves over time. This means that otherwise "expensive" forms of clean dispatchable generation or longer-duration storage can add significant value at the margin once high penetrations of variable renewables and shorter-duration storage have been reached. The technologies are also complementary. Higher levels of long duration storage can increase the capacity factors and therefore reduce the true levelized cost of intermittent renewables by enabling storage and use for temporarily excess renewables generation. In short, a balanced set of technologies with a variety of characteristics will be needed to achieve a low-cost, reliable, carbon neutral power system.

While the capacity factor assumption for generation technologies can serve as a good proxy for measuring the declining value in LCOE calculations, it is more difficult to measure for storage technologies. This is because storage technologies can service a broad "value stack," from frequency regulation to spinning reserve to energy arbitrage and beyond. Schmidt et al. make an admirable attempt to categorize discrete applications for storage technologies (with an accompanying operating profile) and calculate an LCOS for each application (*Schmidt et al.*, 2019). This approach provides a useful comparison of the viability of various storage technologies for each application, but it would be overly simplistic to view these LCOS calculations as true cost estimates for the technologies (e.g. to compare to dispatchable generation technologies). Real-world operating profiles of storage assets are ultimately grid specific and would likely combine a variety of value generating applications.

For these reasons, the LCOE and LCOS estimates should be regarded as providing a broad directional view of the relative cost of the technologies discussed in this report. We characterize the current estimated cost of these technologies as well as their projected future cost (based on available published forecasts) in order to understand which technologies might become competitive in the coming decades (when they will be needed as variable renewable penetrations increase) even if not competitive today. We also recommend further work to develop a detailed electricity system model for

Virginia to fully understand the combinations of technologies that will provide a clean, low-cost, reliable grid.

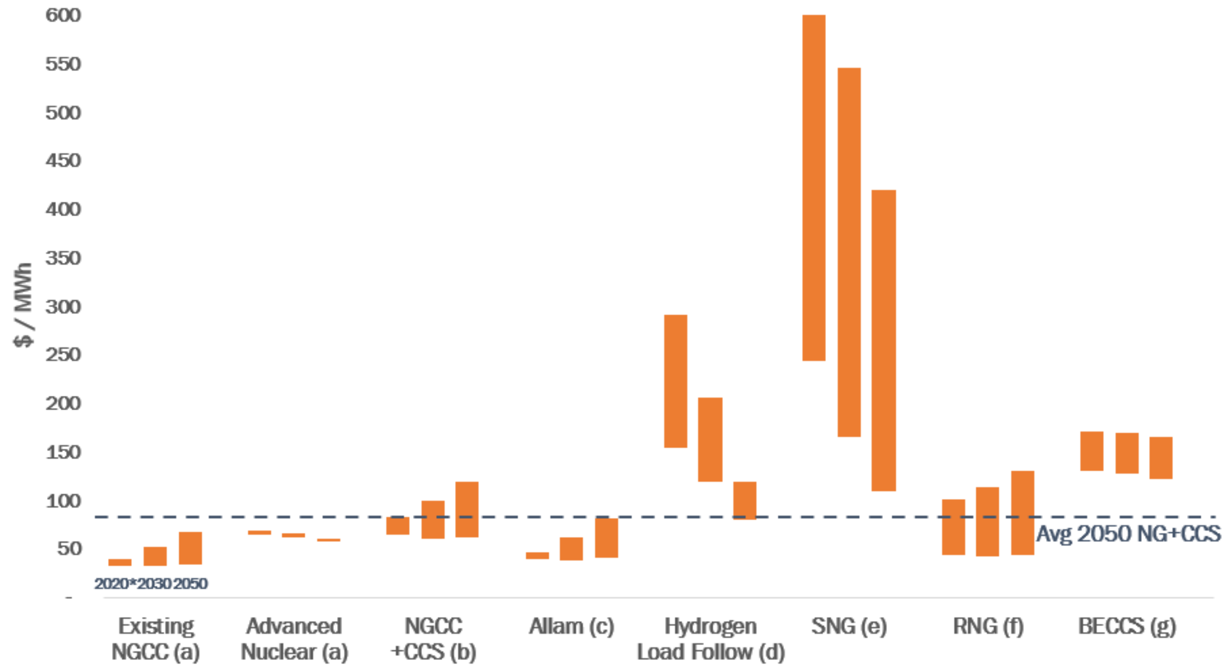
In order to represent the most meaningful “apples to apples” comparison, we group the cost assessments into three categories according to the application of the technology:

- Baseload generation
- Peaking generation or dispatchable storage (defined as four hours)
- Longer-duration storage (discussed directionally without quantifying)

This grouping allows us to account for levelized cost applied over a reasonably consistent operating model (projects generating close to 100% of the time vs. projects frequently used to fulfill short periods of peak demand vs. projects used only during extended periods of shortfalls in variable renewable production). This is a simplified approach that should be expanded to allow technologies to service their full range of potential applications in a robust system modeling effort, but it is helpful to indicate the relative competitiveness of the technologies discussed in this report.

4.2.1 Baseload Generation

We characterize baseload generation as projects generating electricity close to 100% of the time, which limits the analysis to the fuel- or feedstock-powered clean dispatchable generation technologies discussed in this report. LCOE calculations for each of these technologies are displayed in Figure 2, including forecasted costs in 2030 and 2050. As previously discussed, these figures are purely indicative, but they demonstrate a view of the relative competitiveness of the technologies today and where they may trend in the future.



* Base year figures actually vary from 2017-2019 depending on the source data
a From NREL 2019 Annual Technology Baseline
b From NREL 2019 Annual Technology Baseline; 20% adder for carbon storage and transportation costs per Leung et al (2014)
c Cost estimates not available in authoritative sources; indicative costs based on existing NGCC (per claims of Allam developers) with 20% adder for CCS storage and transport
d From BNEF "Hydrogen Economy Outlook" (2020)
e Calculated by substituting fuel cost projections per The Brattle Group (Weiss, 2019) into NGCC LCOE above
f Calculated by substituting fuel cost projections per NREL (Fei, 2015) into NGCC LCOE above
g From NREL 2019 ATB for biomass; CCS adder applied similar to NGCC+CCS vs. NGCC, including 20% adder for carbon storage and transp. costs per Leung et al (2014)

Figure 2: Baseload Generation LCOE Forecast

The following cost estimates deserve further comment:

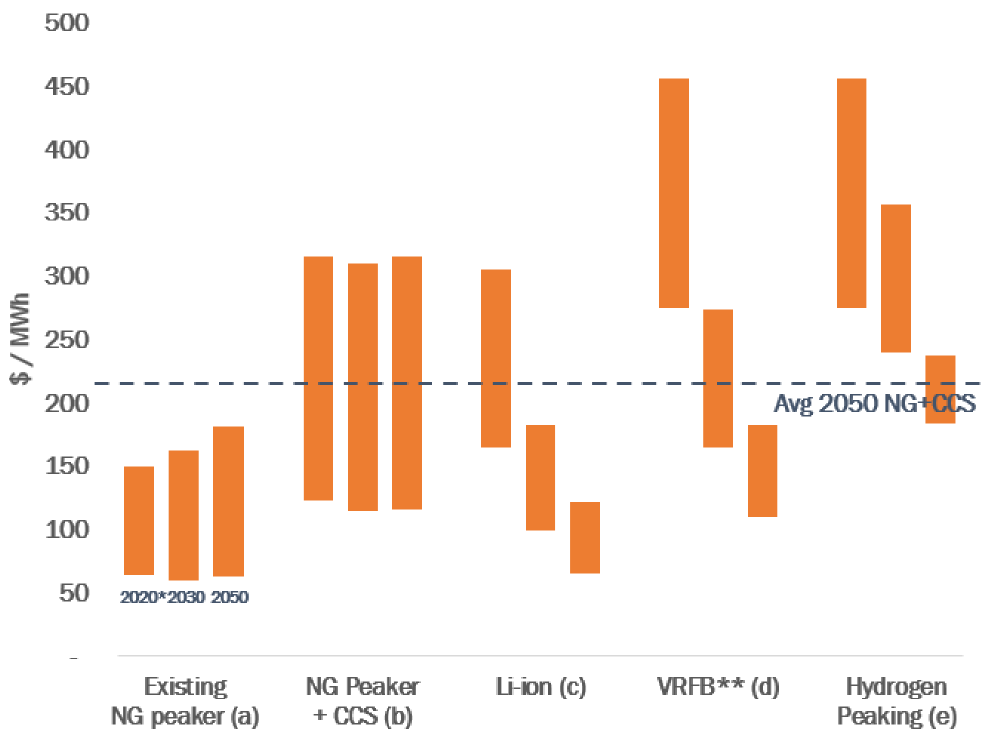
1. Existing natural gas combined cycle (NGCC) is shown here for reference, but it would not qualify as a clean dispatchable power generation technology.
2. NGCC + CCS indicates the cost to build a new facility. Retrofit projects would be less expensive, but the viability of retrofitting Virginia's fleet needs to be studied further (as not all plants are equally "CCS-ready," and such a retrofit on a natural gas power plant has never been done). Rubin et al. list reasons why CCS retrofits can be challenging (site-specific integration and optimization challenges, additional flue gas cleaning equipment, lower efficiencies, etc.) (*Rubin et al.*, 2015). A paper from the Clean Air Task Force indicates that CCS retrofits of existing NGCC plants would provide a 10-20% cost advantage (on an LCOE) basis relative to greenfield NGCC + CCS projects (*CATF*, 2017). The NGCC + CCS case excludes any carbon pricing or revenue from carbon commodity sales, which would improve the economic assessment for the technology.
3. Advanced nuclear is derived from NREL's Annual Technology Baseline and is based on EIA data for one nuclear plant type (Westinghouse AP1000), thus the small variance in levelized costs. While this Generation III reactor type is less advanced than the "advanced" nuclear technologies described in this paper, these costs are in line with NuScale's LCOE target of

$65/MWh for their first full-scale power plant. As new, modular advanced nuclear types are developed, their costs may differ from those shown here.

4. The Allam Cycle is a development-stage technology without proven costs. The figures shown here are purely indicative based on claims from NET Power that projects can deliver costs similar to existing NGCC plants, with the addition of our estimate for storage and transportation of CO_2.
5. Hydrogen "load follow" is derived from a BNEF study and is likely based on lower capacity factors than typical baseload operations would indicate. If so, the LCOE would decrease in line with higher capacity factors.
6. SNG here appears to be relatively uncompetitive, but it should be noted that the wide range is due to highly uncertain cost decline pathways for the green hydrogen and captured CO_2 that would be used to create SNG. It is possible that SNG could be competitive as a niche fuel in an energy system with occasionally zero-cost electricity for electrolysis and a carbon supply chain in need of utilization cases to avoid the cost of storage. Notably, the LCOE considers a greenfield SNG-fired power plant; a retrofit of an existing natural gas-fired plant would be less expensive and should be studied further.
7. RNG costs depend significantly on the feedstock, as landfill gas has been demonstrated at multiples cheaper than dairy farms (the full range is indicated here). Notably, the LCOE considers a greenfield RNG-fired power plant; a retrofit of an existing natural gas-fired plant would be less expensive and deserves further study.
8. BECCS, similar to NGCC + CCS, does not contemplate a carbon price or revenue from carbon commodity sales, which would improve the economic assessment for the technology.

4.2.2 Peaking Generation or Dispatchable Storage

We characterize peaking generation or dispatchable storage as projects generating electricity to cover relatively brief periods of peak demand in Figure 3. This allows us to assess clean dispatchable generation technologies operating at low capacity factors (typically 10-30% depending on the source used) alongside energy storage technologies providing up to four hours of storage capacity (the standard used in Lazard's latest LCOS report). We only show LCOE/LCOS for technologies available in the literature, but it is important to note that other clean dispatchable generation technologies shown in the baseload application group could be operated at lower capacity factors in this peaking application with a similar cost increase (as long as the technology is technically capable of operating at such low capacity factors).



* Base year figures actually vary from 2017-2019 depending on the source data
** Vanadium Redox Flow Batteries (the most mature flow battery technology)
a From NREL 2019 Annual Technology Baseline
b CCS adder applied similar to NGCC+CCS vs. NGCC, incl. 20% adder for carbon storage and transp. costs per Leung et al (2014)
c From Lazard's LCOS v5 for 4-hr storage in wholesale mkt. application; cost declines 5% p.a. to 2030, 2% p.a. to 2050
d From Lazard's LCOS v4 for 4-hr storage in wholesale mkt. application; cost declines 5% p.a. to 2030, 2% p.a. to 2050
e From BNEF's "Hydrogen Economy Outlook" (2020)

Figure 3: Peaking Generation + Dispatchable Storage – LCOE/LCOS Forecast

The following peaking and higher frequency storage costs deserve further comment:

1. It is important to emphasize that the storage technologies could participate in a larger "value stack" beyond providing peaking capacity, and any such operating profiles would need to be assessed as part of a robust energy system model to understand their impact on the economic value of the storage assets.
2. In addition to lithium-ion and flow batteries, Schmidt et al. find that pumped hydro, compressed air, and NaS batteries could provide competitive peaking capacity services. Those LCOS figures are not included because they could not be validated against the Lazard methodology. Importantly, Schmidt et al. estimate that the battery technologies (including lithium-ion, flow batteries, and high temperature batteries) have greater potential for cost reduction—up to 50% or more to 2050—than the mechanical storage technologies like pumped hydro and compressed air (*Schmidt et al.*, 2019).
3. Lithium-ion and flow battery cost declines were applied to Lazard's latest current estimates based on learning rates in line with those applied by Schmidt et al. and BNEF (*Goldie-Scot*, 2019; *Schmidt et al.*, 2019).

4. Current and projected LCOE/LCOS costs for natural gas peaking facilities and lithium ion batteries sheds some light on why the market is moving toward deployment of lithium-ion batteries at scale to replace aging natural gas peaking capacity.
5. A limitation of the "peaking" LCOS analysis is that storage assets are modeled at four hours of discharge duration, when there will likely be longer periods of discharge needed, either in applications that could be considered "peaking" or to cover longer, weather-related periods of low variable renewable generation. Though dominant in four-hour applications, lithium-ion batteries become technically limited in longer-duration applications and therefore more costly (as redundancy is required in order to discharge units sequentially). We discuss longer-duration applications in the next section.

4.2.3 Long-duration Storage

We characterize long-duration storage as projects capable of discharging over relatively long periods of demand in excess of variable renewable generation (e.g. from eight hours up to days, weeks, or even months). Because of the lack of current commercial applications for long-duration storage, the literature is not robust around estimating the levelized cost of such technologies. Any such levelized cost calculation is subject to the operating profile defined as "long-duration" and would differ significantly from real projects to the extent their actual operating profile is different.

Schmidt et al. helpfully include a "seasonal storage" application in their review and forecast of storage technology costs. They define "seasonal storage" as "compensat[ing] long-term supply disruption or seasonal variability in supply and demand" and model an operating profile of 500-2,000 MW system size, 24-2,000-hour duration, 1-5 cycles per year, and slow response time required (*Schmidt et al.*, 2019). This is a more limited application than we envision for long-duration storage, but it is perhaps the best proxy as our envisioned application would include the need to discharge for long periods up to and in excess of 24 hours. Because the levelized cost numbers for the authors' "seasonal storage" application are so high (a function of very few annual cycles), we do not include them here to avoid confusing readers as to their meaning. But we do summarize the authors' conclusions regarding which storage technologies seem most suited to this "seasonal" application.

Based on the operating profile they define for "seasonal storage," Schmidt et al. determine that only four technologies are well-suited to such long durations: pumped hydro, compressed air, flow batteries, and hydrogen. This aligns well with our review. The authors go on to calculate LCOS forecasts for these four technologies applied to seasonal storage, finding that by 2030, hydrogen is the most economic technology, and this advantage increases to 2050. Notably, the authors project very little cost decline for pumped hydro and compressed air, as these are the two more technically mature solutions (with the caveat that adiabatic compressed air must be developed further). Meanwhile, both hydrogen and flow batteries are projected to decline substantially in cost as the as electrolysis and flow battery technologies mature and scale (*Schmidt et al.*, 2019). Hydrogen and flow batteries also have the advantage of being well-suited to serve more potential applications than pumped hydro and compressed air, which could increase their value proposition and hasten their deployment.

4.3 Synthesizing the Assessments

In order to holistically compare all the relevant technologies discussed in this report, we evaluate them along two dimensions: "technical readiness" and "value." Technical readiness reflects the assessments of maturity while value considers the majority of the other qualitative and quantitative factors, including relative LCOE/LCOS ranking, scalability, and environmental rating, as well as a "grid value" score based on the number of use cases a technology can serve, reliability, and flexibility.

These two dimensions are used to group the resulting matrix into indicative policy and planning guidance for each technology. Technologies in the upper right should be considered for investment in pilot or demonstration-scale projects or other supportive policies to enable market participation. For technologies bordering the upper right quadrant, further evaluation, with a focus on the technical hurdles that remain to be cleared and economic uncertainties that must be resolved, would be justified. More detailed, technology-specific analysis in the future could refine our assessment or reveal opportunities to accelerate technology development. Technologies in the bottom left should be monitored for continuing improvements that might create a basis for targeted investment or policy support in Virginia.

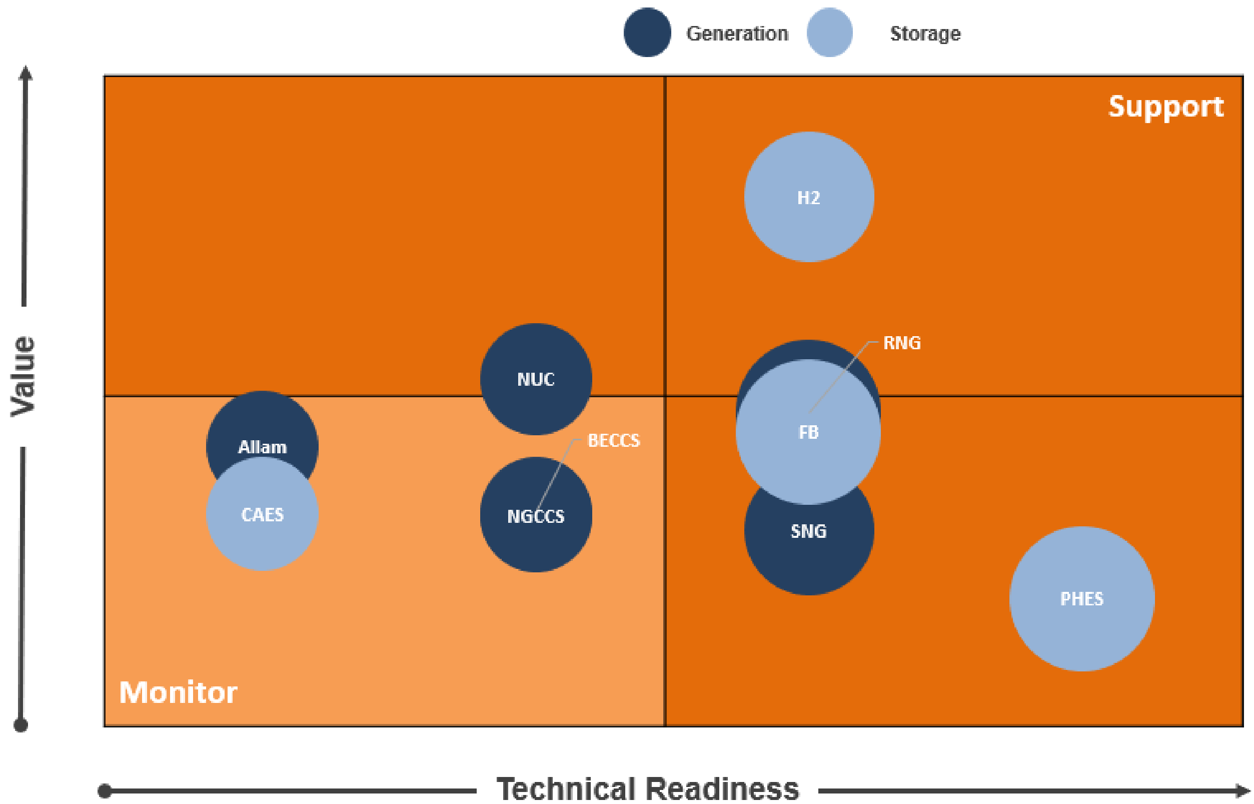


Figure 4: Clean Dispatchable Technologies assessed by Value and Technical Readiness

We summarize an initial interpretation of this analysis for each technology as follows, with more detailed conclusions and recommendations in the final section of the report.

H2 (Hydrogen): With relatively high technical maturity, the ability to serve multiple use cases, and a widely forecasted reduction in cost over the next 10-20 years, clean hydrogen scores well in this analysis. Remaining hurdles related to storage infrastructure (for long-duration use cases) and extensive commercial deployment (to drive cost declines) should be targeted with supportive policies.

RNG (Renewable Natural Gas): With high technical maturity, the ability to serve multiple use cases, and a competitive cost profile (assuming cheaper forms of feedstock), renewable natural gas scores well and should be targeted for expanded capacity with supportive policy. In order to drive growth, market/regulatory reforms are needed to allow injection of RNG into existing transmission and distribution pipelines, and commercial deployment is needed to demonstrate fuel switching from fossil gas for utility-scale power production. Total RNG capacity in the Commonwealth may not be capable of providing the entirety of clean dispatchable power needed in a high-VRE grid, but it can be a significant contributor.

FB (Flow Batteries): As energy storage deployment increases, flow batteries are one of the most promising alternatives to lithium-ion with the ability to deliver longer-duration use cases. The mobilization of resources and policy tools in the Commonwealth toward storage technologies should explicitly include a robust evaluation of flow batteries as a scalable solution. In particular, market reforms must enable battery and other storage technologies to participate in electricity supply, capacity and ancillary grid services markets. Policies that encourage private investment and deployment-driven innovation and cost reductions will also be needed.

SNG (Synthetic Natural Gas): Despite high costs, synthetic natural gas should be considered as a potentially valuable tool for dispatchability in a high-VRE grid to the extent that robust supply chains develop for its inputs (hydrogen and captured CO_2). Synthetic fuels are worth studying as part of a broader hydrogen-powered future.

PHES (Pumped Hydro Energy Storage): While pumped hydro is the most mature of all energy storage technologies, its value is limited by land constraints, high (and uncertain) costs, and the potential for negative environmental impacts that accompany large infrastructure. New PHES facilities should be considered as part of the Commonwealth's clean energy goals, but only with careful consideration of the alternatives and the full set of costs and benefits.

NUC (Advanced Nuclear): Advanced nuclear technologies (including small modular designs) claim to satisfy many of the traditional concerns with nuclear power generation and show promise to deliver significant value as flexible, dispatchable clean generation sources. Additional demonstration projects for modular and other next generation nuclear technologies are needed to validate claimed cost and safety improvements. Regulatory reforms will also be needed to allow advanced nuclear plants to be approved and sited on a reasonable timescale. Virginia has an opportunity to lead on advanced nuclear deployment.

NGCCS (Natural Gas with Carbon Capture and Storage): Retrofitting existing natural gas generation facilities with carbon capture technology is an understandably attractive option to reduce emissions while leveraging existing infrastructure. Based on our review, significant hurdles remain before moving forward with CCS retrofit projects. Transportation (pipeline infrastructure), economically accessible storage, and utilization cases (commercialization of which would improve economics of the technology) for captured CO_2 all need development. Commercial deployment of CCS on natural gas plants has never been done and is needed to demonstrate viability and cost. Amine pollution from operations, carbon leakage from storage, and methane emissions during extraction, processing, and transportation of natural gas must also be addressed. Even with improved carbon capture technology, CCS is not likely to be a greenhouse gas neutral process. The technology should be monitored for further developments while economically accessible options for large-scale, long-term sequestration in Virginia is studied further.

Allam Cycle: The Allam Cycle is less proven than traditional forms of CCS but potentially more cost-competitive. Hurdles related to transport, commercial use and/or sequestration of CO2 are the same as those for other carbon capture technologies. Progress towards commercial deployment of Allam Cycle technology should be monitored as the broader issues related to CCS are assessed.

CAES (Compressed Air Energy Storage): Adiabatic methods (those that do not require fossil fuel-powered equipment) are still pre-commercial with costs that are not well-understood. This technology offers the potential for significant long-duration energy storage capacity and should be monitored for further development while the viability of natural storage sites in Virginia is studied further.

5 CONCLUSIONS, RECOMMENDATIONS, AND POLICY IMPLICATIONS

Our conclusions and recommendations are based on the technology assessments summarized in this report. We also take into account recent policy and planning developments in Virginia, including the VCEA and related clean energy legislation, Dominion's 2020 IRP filing, and national and state-level modeling studies of electricity system decarbonization pathways.

Key Conclusion #1: Existing renewable energy and short-term storage technologies are ready for deployment at scale to meet mid-term goals

Solar, wind, and lithium-ion (or equivalent) battery technologies, in combination with increases in energy efficiency and demand flexibility, can meet Virginia's mid-term decarbonization goals. Achievement of the VCEA's 2030 goal of 30% renewable generation is supported by the mandated deployment of at least 16 GW of onshore wind or solar, 5 GW of offshore wind, and 3 GW of energy storage by 2035 (*Williams Mullen*, 2020). Such a deployment could supply approximately 65% of Virginia's current electricity demand.[11] In line with these mandates, Dominion's latest 2020 IRP proposal includes four scenarios ranging from 7-19 GW of new solar, 5 GW of offshore wind, 3-10 GW of energy storage, and 5-10 GW of new out-of-state imports. Dominion maintains that ~1 GW of new natural gas peaking facilities will likely be required to maintain system reliability in the mid-term, but envisions that these facilities could eventually be replaced and/or retrofitted to accommodate emerging clean technologies like CCS or biogas (*Dominion*, 2020). Coordinated planning and appropriate incentives will be required to ensure cost-effective deployment and integration of these technologies to meet Virginia's 2030 clean energy goals, but there are no technical barriers to doing so, and with the possible exception of offshore wind, no requirement for cost reducing innovation.

Key Conclusion #2: Technologies are in development that could provide cost-effective clean, dispatchable power in the long-term

Numerous technologies are in development that have the potential to cost-effectively supplement intermittent renewables and short-duration batteries with clean dispatchable generation and long-duration storage. Policies that support continued development and commercialization of these technologies will help ensure that Virginia meets its longer-term clean energy goals at reasonable cost.

While existing, commercially available technologies can likely meet mid-term clean energy targets, additional storage and clean dispatchable power technologies will likely be needed to achieve longer term decarbonization goals. Our analysis indicates that there are a number of technologies in development that could enable Virginia to achieve a 100% clean electric grid and support decarbonization of other sectors of the economy. A detailed 2019 modeling study conducted to establish pathways to 100% clean electricity in New Jersey provides relevant insights from a state with many of the same challenges and opportunities as Virginia. The New Jersey study found that a least-cost pathway included the following elements by 2050: maintaining the existing nuclear fleet, ramping down fossil gas generation and converting any remaining fossil gas plants to run on a combination of hydrogen and biogas, major expansions of solar and offshore wind, a significant new transmission buildout, and relatively robust (~20%) imports of low-cost clean energy from other states within the

[11] Assuming 80% of the 16 GW mandate is solar at 25% capacity factor, 20% of the 16 GW mandate is onshore wind at 45% capacity factor, 5 GW offshore wind at 55% capacity factor, and storage deployment is sufficient to allow zero curtailment. This estimate is purely indicative; increased electricity demand (from vehicle electrification, data centers, etc.), demand flexibility, energy efficiency, and differences in the timing of renewable generation vs. demand could all affect the actual percentage of generation from renewables and should be modeled carefully.

PJM interconnection system. While the study finds that the majority of in-state generation can be supplied with VRE, the least cost scenario includes 20-30% from nuclear and other "firm capacity" from biogas, green hydrogen or other sources, as well as ~10% of total capacity from energy storage (*NJBPU*, 2019). Virginia and New Jersey certainly have their differences, but this study provides an indication of the kinds of technologies and pathways available in Virginia, including the need for solutions beyond solar, wind, and lithium-ion batteries to get to a 100% carbon-free grid.

Recommendation #1: Establish a policy environment that supports private investment and enables broad innovation

While existing technologies can deliver mid-term goals, investment and policy decisions made today will help determine the technology pathways that are viable in the long-term (e.g. Dominion's plans to build new natural gas peaking capacity in the near-term). Today's low-cost renewable generation and (increasingly) low-cost lithium-ion battery storage technologies took years of R&D, public incentives, and deployment at scale to reach the point of maturity and cost-competitiveness where they are today. Other new technologies will be no different.

In this report, we find that a number of clean dispatchable generation and long-duration storage technologies could be viable contributors to a 100% clean electricity system in Virginia. We therefore recommend a policy environment that supports broad-based innovation, while enabling rapid commercialization of promising later stage technologies. Policy initiatives that could be pursued in the near-term include:

- Development, ideally in collaboration with the Federal Energy Regulatory Commission (FERC) and PJM, of retail rates and wholesale market pricing structures that enable commercially deployed energy storage technologies to benefit from the full "value stack" of energy, capacity and ancillary services they provide to the grid.
- Pilot- and demonstration-scale projects, potentially conducted in collaboration with other states across PJM and/or the Regional Greenhouse Gas Initiative (RGGI), of clean dispatchable and longer-term storage technologies in late stages of development that have the potential for continued cost reductions, leverage existing infrastructure, and/or have the potential to contribute across multiple grid or economy-wide applications.
- Initiate planning processes and, where appropriate, demonstration projects to evaluate options for developing infrastructure to support commercialization of these technologies in Virginia (e.g. pipeline and storage capacity for hydrogen and long-term sequestration options for CO_2 generated from CCS technologies). These investigations and demonstration projects would also benefit from collaboration with other states across PJM and/or RGGI.

Recommendation #2: Support development of promising technologies where Virginia could provide leadership in the energy transition.

Several highly promising clean dispatchable and long-term storage technologies are on the verge of transitioning from development to commercialization and could benefit from public support to accelerate commercial scale evaluation or market uptake. Virginia should invest in areas where the state has inherent advantages to be a leader in the energy transition and where there are additional benefits such as development of supply chains, green jobs creation, or economic development in lower income communities.

Energy Storage. As discussed in this report and widely throughout the literature, energy storage technologies are diverse and rapidly evolving. The VCEA includes aggressive mandates for energy storage procurement, much of which will likely be lithium-ion in the near-term. Virginia could more explicitly encourage the development of technologies with longer-duration potential by carving out some portion of the VCEA's mandates (e.g. 100 MW) for pilot- or demonstration-scale projects using flow batteries and other lithium-ion alternatives. Virginia House Bill 1183, signed in April 2020, directs the State Corporation Commission to convene a task force to evaluate the regulatory environment for bulk energy storage (*HB 1183*, 2020). We encourage the SCC to ensure the task force evaluates a wide range of technologies, including alternatives to lithium-ion batteries and technologies capable of longer-duration storage applications, such as those discussed in this report.

<u>Geological Storage Study</u>. Naturally occurring geological storage is a critical component of several technologies discussed in this report, including carbon sequestration, seasonal hydrogen storage, and compressed air energy storage. Although storage of CO_2, hydrogen, and compressed air dictate unique requirements, many of the key features of geological storage formations are shared. Virginia should commission a study to document the location and extent of possible geological storage formations within the Commonwealth and surrounding region in order to demonstrate the viability of developing such technologies at scale. The formations studied could include abandoned coal and shale gas sites in addition to naturally occurring saline and other geological formations.

<u>Advanced Nuclear</u>. Nuclear power currently produces 95% of the state's carbon free electricity and directly employs over 2,000 workers at Dominion's North Anna and Surry sites (*NEI*, 2020). In addition, Virginia is the headquarters for two major nuclear manufacturers and service providers – BWX Technologies and Framatome – that employ an additional 2,000 workers in the Lynchburg area (*Opportunity Lynchburg*, 2019). The existing four nuclear power units in Virginia are due to continue operating well into the 2030s (the last operating license expires in 2040), and potentially an additional 20 years if their operating licenses are renewed (*NRC*, n.d.-b). If SMRs and advanced reactors (with improved safety and waste management features) prove they can be installed at lower capital costs and LCOEs while enabling a more flexible grid, nuclear power could contribute significantly to achievement of Virginia's clean economy goals. With an existing trained workforce and supply base within the state, the Commonwealth has the opportunity to lead the U.S. in the development and deployment of SMRs and advanced reactor designs.

<u>Hydrogen</u>. The production and distribution of clean hydrogen has significant potential in decarbonizing not just the power sector, but also transportation, industrial processes, building energy management, and agriculture. Use of hydrogen directly or as a feedstock for synthetic fuels is the only set of technologies evaluated in this paper that have such a broad reach across the energy landscape. Virginia can begin to support development of a hydrogen economy within the state by leveraging its extensive natural gas infrastructure and planning for green hydrogen production from offshore wind energy. Possible initial applications in the Commonwealth that do not require a complete overhaul of storage and distribution infrastructure include powering fleets of trucks and buses, material handling equipment (e.g. forklifts and pallet jacks), and backup power generation. Virginia could also experiment with blending green hydrogen into existing natural gas pipelines to lower the carbon intensity of the system, as has been done in Hawaii where approximately 12% of pipeline gas is hydrogen (*Hawaii Gas*, n.d.). Steam reforming of natural gas is the lowest-cost method of producing hydrogen at scale and can be used initially to build production and network capabilities. In the longer term, green hydrogen production from offshore wind may be an ideal match as the technology offers high capacity factors (as compared to onshore wind and solar) and seawater can be used for on-site production. There is growing interest in offshore wind power-to-gas by several companies, including the development of a 400 MW hydrogen offshore platform by Tractebel Engineering (*Riviera*, 2019). With the apparent success of Dominion's 12 MW Coastal Virginia Offshore Wind pilot, the utility is

primed to begin construction of a 2.6 GW offshore wind project in the mid-2020s (*Stromsta*, 2020b). By combining Virginia's expansive offshore resources with green hydrogen production, the state could take a large step towards decarbonization of not only the electric grid but also the broader economy.

CCS Retrofit Suitability Study. The addition of CCS technology to existing natural gas-fired generation facilities is an appealing pathway to decarbonization, but the studies cited in this report indicate that feasibility and costs of such retrofits depend on design and equipment of each plant. Given the investment Virginia has made over the past decade in new gas-fired generating facilities, many of which are at risk of becoming stranded assets, the state should commission a study to determine the technical viability and potential cost of CCS retrofits to its newer gas generating plants.

Renewable Natural Gas. While Virginia has largely exhausted its landfill capacity for renewable natural gas, capacity remains for over 150 wastewater and manure-fed systems (*American Biogas Council*, 2020). The Commonwealth should request further information from Dominion and Appalachian Power to understand the viability of developing such systems in a cost competitive manner, similar to what Dominion has accomplished in neighboring states.

Recommendation #3: Conduct additional modeling of the Virginia electric grid to explore pathways to a 100% clean electric supply and assess the role of longer-duration storage and clean dispatchable power in a decarbonized energy system

As previously noted, the generalized economic assessments and levelized cost studies utilized in our analysis have limitations as indicators of the value new technologies can provide as part of a flexible, rapidly evolving electric grid. Additional insights can be provided by incorporating these technologies in integrated modeling studies of the Virginia electric grid and broader energy system. These studies should utilize technology cost and performance projections from this and other leading reviews, evaluate the full complement of grid services that each technology option can provide, and assess how sensitive results are to key assumptions and uncertainties. The modeling and technology analysis should be conducted in the context of an electricity supply mix that will increasingly rely on intermittent renewables and electricity demand projections and load profiles that include increasing electrification of transportation and other end uses. Ideally, this type of rigorous, integrated assessment of clean energy and decarbonization pathways for Virginia should be updated on a regular basis to review and refine technology and policy options.

APPENDIX A – INDIVIDUAL TECHNOLOGY ASSESSMENTS

Natural Gas with CCS

Criteria	Rating	Rationale
Technical Readiness	2	Capture technology has been commercialized but never at a natural gas power plant, and storage options are not well developed outside of EOR.
Scalability	2	The possible market for deployment is large with existing fossil fuel facilities, but capture technology is typically bespoke and engineering/capex heavy (not modular). Scalability of feasible storage capacity is a significant unknown.
Reliability	4	Operating facilities assume the reliability of the underlying natural gas power plant, which is high.
Flexibility	4	Operating facilities assume the flexibility of the underlying natural gas power plant, which is high (particularly for plants operating as peakers).
Environmental Rating	1	CCS technologies available today do not capture 100% of CO_2 emissions. Capturing carbon on the way out also does not address methane and carbon emissions from extracting, processing, and transporting natural gas, and depending on the storage method used, leakage of carbon over time could be an issue.
Applicability to VA	2	Capture technology is highly applicable given the recent buildout of natural gas in Virginia, but the lack of a demonstrated storage method applicable to Virginia is a limiting factor.
Critical Hurdles	T	Transportation (pipeline infrastructure) of CO_2 needs development.
	S	Storage infrastructure for CO_2 sequestration needs development.
	U	Utilization cases (commercialization of which would improve economics of the technology) for captured CO_2 need development.
	C	Commercial deployment on natural gas plants is needed to demonstrate viability and cost.
	E	Environmental impact issues related to amine pollution from operations and carbon leakage from storage must be addressed as well as the continued emissions related to extraction, processing, and transportation of natural gas.

Renewable Natural Gas

Criteria	Rating	Rationale
Technical Readiness	3	RNG production using anaerobic digestion is a relatively mature and commercial-scale technology, although there is a need for demonstration of fuel substitution in natural gas combustion power plants (today's RNG is often either (i) used for heat and/or power onsite or (ii) injected into natural gas pipelines for heating applications, but not for utility-scale power generation).
Scalability	2	Production volume may be limited to 3-6% of current power demand, which is meaningful, but likely insufficient on its own to supply the scale of clean dispatchable power needed.
Reliability	4	Operating facilities assume the reliability of the underlying natural gas power plant, which is high.
Flexibility	4	Operating facilities assume the flexibility of the underlying natural gas power plant, which is high (particularly for plants operating as peakers).
Environmental Rating	3	Life cycle assessment needed for each proposed feedstock to qualify as zero-carbon, and waste and effluents from production must be managed carefully.
Applicability to VA	4	RNG production is a small but mature industry in Virginia.
Critical Hurdles	M	Market/regulatory reforms are needed to allow injection of RNG into existing transmission and distribution pipelines.
	C	Commercial deployment is needed to demonstrate pure fuel switching for utility-scale power production.
	E	Environmental impact issues must be understood and regulated related to the carbon content of feedstocks, fugitive methane emissions and flaring, and waste/effluents from production.

Synthetic Natural Gas and other Hydrocarbons

Criteria	Rating	Rationale
Technical Readiness	3	The underlying chemical processes to synthesize hydrocarbons are mature and electrolyser technology has rapidly developed in recent years, although further improvements are needed before it can compete with grey hydrogen production.
Scalability	2	Producing fuels at scale can be done but relies on massive infrastructure to provide a feedstock of hydrogen and CO_2, which would rely on specialized storage facilities.
Reliability	4	Operating facilities assume the reliability of the underlying power plant, which is high.
Flexibility	4	Operating facilities assume the flexibility of the underlying power plant, which is high (particularly for plants operating as peakers).
Environmental Rating	2	Synthetic methane faces the same risk of leakage in transportation infrastructure as natural gas. CO_2 capture and storage methods (if needed) face environmental questions (amine emissions, potential CO_2 leakage from storage).
Applicability to VA	3	Hydrogen production is viable in VA, but the CO_2 supply chain is less certain to the extent it relies on storage methods that may or may not be applicable to VA.
Critical Hurdles	T	New or modified transportation (pipelines) infrastructure would be required to accommodate hydrogen, unless the methane or other fuels are produced on-site.
	S	New or modified storage infrastructure would be required to accommodate hydrogen, unless the methane or other fuels are produced on-site.
	M	Regulatory reform is required to create markets for synthetic fuels that reward them for having a carbon-free lifecycle.
	B	Basic technology improvements are needed to reduce the cost of hydrogen production.
	C	Commercial deployment is needed to demonstrate pure fuel switching for utility-scale power production.
	E	Environmental impact issues related to carbon and methane leakage from storage and transportation infrastructure must be addressed.

Allam Cycle

Criteria	Rating	Rationale
Technical Readiness	1	Technology has been demonstrated at a single site but not yet at utility scale, and storage options are not well developed outside of EOR.
Scalability	2	Power plants are purported to be relatively uniform (not bespoke), but scalability of feasible storage capacity is a significant unknown.
Reliability	4	Operating facilities are purported to match the reliability of existing natural gas power plants, which is high.
Flexibility	4	Operating facilities are purported to match the flexibility of existing natural gas power plants, which is high (particularly for plants operating as peakers).
Environmental Rating	2	Significantly reduces water use relative to traditional natural gas plants, but capturing carbon on the way out does not address methane and carbon emissions from extracting, processing, and transporting natural gas. In addition, depending on the storage method used, leakage of carbon over time could be an issue.
Applicability to VA	2	There is no reason the fundamental technology cannot be applied in VA once proven, but the lack of a demonstrated storage method applicable to Virginia is a limiting factor.
Critical Hurdles	T	Transportation (pipeline infrastructure) of CO_2 needs development.
	S	Storage infrastructure for CO_2 sequestration needs development.
	U	Utilization cases (commercialization of which would improve economics of the technology) for captured CO_2 need development.
	B	Basic proof of the technology beyond its first demonstration site is needed.
	C	Commercial deployment is needed to demonstrate viability at scale.
	E	Environmental impact issues related to carbon leakage from storage must be addressed (not to mention the continued emissions related to extraction, processing, and transportation of natural gas).

Advanced Nuclear

Criteria	Rating	Rationale
Technical Readiness	3	Nuclear technology is very mature and new reactor designs are not high-risk from a technology perspective. Purported improvements in modular manufacturing techniques, automation, and passive safety features need to be proven before these designs can compete in the marketplace.
Scalability	3	Currently there is an extensive regulatory burden to build a nuclear plant. Unless microreactors are deployed, each plant would be considered a grid-scale asset.
Reliability	3	Plants must shut down periodically for refueling and maintenance, although on-line refueling may be possible in some designs. Unscheduled shutdowns may occur due to preventative safety measures.
Flexibility	4	Although traditional nuclear plants have been thought of as “baseload” power, advanced nuclear plants will be built with load following capabilities and can be operated similar to gas peakers.
Environmental Rating	2	Without a federal policy, nuclear waste requires temporary storage to prevent release to the environment. Mining of uranium and other heavy metals is required for fuel and plant equipment.
Applicability to VA	4	Dominion Energy has extensive experience operating nuclear power plants in Virginia.
Critical Hurdles	M	Regulatory reforms are needed to allow advanced nuclear plants to be approved and sited on a reasonable timescale that does not hinder their acceptance in the marketplace.
	C	Commercial deployment of small and advanced nuclear plants is needed to demonstrate cost and safety improvements.

Biomass with CCS

Criteria	Rating	Rationale
Technical Readiness	2	Capture technology has been commercialized but never at a biomass power plant, and storage options are not well developed outside of EOR.
Scalability	1	Existing biomass facilities are limited, and new facilities might face land use and transportation constraints depending on feedstock. In addition, capture technology is typically bespoke and engineering/capex heavy (not modular). Scalability of feasible storage capacity is a significant unknown.
Reliability	4	Operating facilities would be as reliable as existing coal or gas plants.
Flexibility	4	Operating facilities would be as flexible as existing coal or gas plants (particularly for plants operating as peakers).
Environmental Rating	2	Water and land use implications depend on the feedstock used, and depending on the storage method used, leakage of carbon over time could be an issue.
Applicability to VA	2	Despite the scale limitations, the underlying technology is perfectly feasible in VA given access to feedstocks, but the lack of a demonstrated CO_2 storage method applicable to Virginia is a limiting factor if the addition of CCS is critical.
Critical Hurdles	T	Transportation (pipeline infrastructure) of CO_2 needs development.
	S	Storage infrastructure for CO_2 sequestration needs development.
	U	Utilization cases (commercialization of which would improve economics of the technology) for captured CO_2 need development.
	C	Commercial deployment on biomass plants is needed to demonstrate viability and cost.
	E	Environmental impact issues related to land and water use as well as carbon leakage from storage must be addressed.

Lithium-ion Batteries

Criteria	Rating	Rationale
Technical Readiness	4	Although there is room for continued cost declines, Li-ion batteries are now a mature technology with demonstrated commercial applications at utility scale.
Scalability	3	The scale of Li-ion battery deployment may arguably be limited by raw material supply chains, but the extent of this limitation is unclear. And unlike flow batteries, energy capacity cannot be engineered independently from power capacity (since all the chemistry occurs in one cell), which limits the returns to scale. In other words, the duration of electricity output cannot be extended without adding more battery packs. Otherwise, battery technologies are modular and inherently scalable.
Reliability	3	Operating facilities have demonstrated reliability, but incidents like the 2019 explosion in Arizona raise important safety concerns about thermal runaway that should be managed.
Flexibility	4	Battery technologies offer high flexibility due to rapid response times that equip them for a variety of grid services.
Environmental Rating	2	Sourcing and recycling of lithium and cobalt pose risks for an otherwise clean technology.
Applicability to VA	4	Battery technologies are not geographically dependent.
Critical Hurdles	M	Market reforms are needed to allow batteries to participate in as many pieces of the "value stack" (i.e. various grid services) as they can deliver.
	B	Some basic technology improvement is necessary to continue to drive down cost.
	C	Further commercial deployment at the grid scale will continue to prove different compensation models.
	E	Environmental impact issues related to sourcing and recycling raw materials must be addressed.

Flow Batteries

Criteria	Rating	Rationale
Technical Readiness	2	Some early commercial activity is proving the technology, but further development is needed to compete with alternatives at scale.
Scalability	4	Vanadium (the most mature flow battery material) is a more abundant element than lithium or cobalt and can even be extracted from industrial wastes. Flow batteries also have the key engineering advantage of scaling energy capacity (by adding more tanks) without investing in more power capacity (adding more cell stacks), which makes it well-suited to long-duration applications with economic returns to scale.
Reliability	3	Early commercial deployment is proving reliability, and the technology theoretically lasts longer than lithium-ion without the fire hazards, but electrolyte leakage must be managed.
Flexibility	4	Battery technologies offer high flexibility due to rapid response times that equip them for a variety of grid services.
Environmental Rating	3	Vanadium's abundance is a key advantage, but electrolyte leakage must be managed.
Applicability to VA	4	Battery technologies are not geographically dependent.
Critical Hurdles	M	Market reforms are needed to allow batteries to participate in as many pieces of the "value stack" (i.e. various grid services) as they can deliver.
	B	Basic technology improvement is necessary to continue to drive down cost (particularly the cost of sourcing vanadium).
	C	Further commercial deployment at scale is needed to prove the technology and compensation models.
	E	Environmental impact issues related to sourcing and recycling materials and managing electrolyte leakage must be better understood as the technology scales.

High Temperature Batteries

Criteria	Rating	Rationale
Technical Readiness	2	Some early commercial activity has proven the technology internationally, but further development is needed to compete with alternatives at scale.
Scalability	3	Unlike flow batteries, energy capacity cannot be engineered independently from power capacity (since all the chemistry occurs in one cell), which limits the returns to scale. Otherwise, battery technologies are modular and inherently scalable.
Reliability	2	Early commercial deployment is proving reliability, but corrosion issues persist due to the high operating temperatures required.
Flexibility	4	Battery technologies offer high flexibility due to rapid response times that equip them for a variety of grid services.
Environmental Rating	4	Materials are non-toxic and 99% recyclable.
Applicability to VA	4	Battery technologies are not geographically dependent.
Critical Hurdles	M	Market reforms are needed to allow batteries to participate in as many pieces of the "value stack" (i.e. various grid services) as they can deliver.
	B	Basic technology improvement is necessary to mitigate corrosion issues and the high cost of operating at high temperatures.
	C	Further commercial deployment at scale is needed to prove the technology and compensation models.

Pumped Hydro

Criteria	Rating	Rationale
Technical Readiness	4	Pumped hydro is the most mature energy storage technology in the world.
Scalability	1	Facilities are heavily geography-dependent and are bespoke, engineering- and capex-heavy projects that can take up to 10 years to develop and construct.
Reliability	4	Operating facilities' track record on reliability is strong.
Flexibility	3	Facilities can be operated flexibly to provide a variety of grid services, but response times of minutes rather than instants preclude the technology from certain applications.
Environmental Rating	2	Like all hydroelectric projects, the size and structure of pumped hydro facilities can involve significant changes in land and water use and disrupt local populations and ecosystems.
Applicability to VA	4	Virginia is home to one of the largest pumped hydro stations in the world and is actively evaluating another.
Critical Hurdles	E	Environmental impacts must be considered carefully in any new major pumped hydro development.
	L	Land constraints must be considered carefully in any new major pumped hydro development.

Block Towers

Criteria	Rating	Rationale
Technical Readiness	1	The technology is "simple," but startup Energy Vault must demonstrate it at scale with further commercial deployment.
Scalability	3	Facilities are not geography-dependent and are theoretically highly scalable, although siting issues, similar to that faced by wind turbines, must be confronted.
Reliability	2	The "simple" technology claims high reliability, but maintenance of cranes and proper functioning of artificial intelligence algorithms are critical.
Flexibility	4	Facilities can be operated flexibly to provide a variety of grid services, with theoretically fast response times driven by automated system.
Environmental Rating	3	Besides land use required for siting projects and supply chain-related emissions to transport cranes and manufacture blocks, this is a theoretically clean technology.
Applicability to VA	4	This technology is not geographically dependent.
Critical Hurdles	C	Significantly more commercial deployment is necessary to prove the technology and its cost.
	E	Environmental impacts of the materials must be addressed (concrete is a notoriously high-emissions material).

Compressed Air Energy Storage

Criteria	Rating	Rationale
Technical Readiness	1	While traditional compressed air storage has been operating at commercial scale for decades, the newer "adiabatic" technology (which does not rely on fossil fuel combustion) is only at the development/demonstration scale.
Scalability	2	Facilities are heavily geography-dependent and are bespoke, engineering- and capex-heavy projects.
Reliability	3	Operating facilities' track record on reliability is strong, but novel approaches like Hydrostor's that consider using existing mine shafts or drilling new purpose-built underground storage systems must prove their reliability at scale.
Flexibility	3	Facilities can be operated flexibly to provide a variety of grid services, but response times of minutes rather than instants preclude the technology from certain applications.
Environmental Rating	3	Depending on the size and structure of compressed air storage facilities, they may disrupt local populations and ecosystems.
Applicability to VA	2	While it is possible that offshore saline aquifers or existing mine shafts in coal regions could be used, storage infrastructure applicable to Virginia is not well-established.
Critical Hurdles	S	Storage infrastructure must be better developed.
	B	Basic technology improvements are needed to demonstrate adiabatic methods.
	C	Commercial deployments are needed to demonstrate viability at scale.
	L	Land constraints must be addressed with a careful evaluation of appropriate sites for large volumes of storage.

Hydrogen

Criteria	Rating	Rationale
Technical Readiness	3	Electrolysers and fuel cells have become mature technologies, although a better understanding is required on how hydrogen can be produced at variable electricity loads (i.e. when otherwise the power would be curtailed).
Scalability	4	Electrolyser units can be stacked in a modular way to achieve utility-scale.
Reliability	3	Fuel cells have become more reliable through deployment in transportation applications, although they are not yet comparable to commercial-scale battery deployments.
Flexibility	4	Fuel cells can react to changes in load very quickly.
Environmental Rating	4	Some rare earth metals are used as catalysts on electrolyser and fuel cell electrodes, but volumes are minimal as compared to some battery chemistries.
Applicability to VA	3	Green hydrogen production is relatively location independent (just needs a source of water and electricity). A lack of natural storage locations in Virginia may limit its use to serving as a load-balancing tool over days and weeks rather than as a method for seasonal storage.
Critical Hurdles	S	Hydrogen storage infrastructure is required, which would need to be quite large for seasonal storage applications.
	C	Commercial deployment is needed to prove out the economics of hydrogen as an energy storage medium.

Low Temperature Thermal Storage ("Liquid Air")

Criteria	Rating	Rationale
Technical Readiness	1	Startup Highview must progress from early commercial demonstrations to utility scale deployments in order to prove the technology.
Scalability	4	Facilities are not geography-dependent and are theoretically highly scalable.
Reliability	3	Reliability of operations at cryogenic temperatures must be demonstrated at scale, but is theoretically high. Most equipment is well-developed and sourced from the oil and gas industry.
Flexibility	3	Facilities can be operated flexibly to provide a variety of grid services, but response times of minutes rather than instants preclude the technology from certain applications.
Environmental Rating	4	As long as energy required to operate the facility is sourced from renewables, this is theoretically a clean technology.
Applicability to VA	4	This technology is not geographically dependent.
Critical Hurdles	B	Additional basic technology improvements are likely required to prove the technology and its cost.
	C	Significantly more commercial deployment is necessary to prove the technology and its cost.

High Temperature Thermal Storage (Molten Salt)

Criteria	Rating	Rationale
Technical Readiness	4	CSP facilities are established in Spain and the western United States, increasingly paired with molten salt storage.
Scalability	2	Facilities are theoretically highly scalable, but they do require sites with a high level of solar irradiation.
Reliability	4	Reliability has been demonstrated at scale.
Flexibility	2	Facilities can be operated somewhat flexibly to provide a variety of grid services, but relatively slow response times preclude the technology from certain applications.
Environmental Rating	4	Outside of ancillary supply chain emissions, this is theoretically a clean technology.
Applicability to VA	1	This technology requires locations with a high level of solar irradiation and may not be feasible in Virginia. If newer approaches like Malta's are demonstrated, they could hold more potential.
Critical Hurdles	L	Land/geography suitability is a limitation that will require high temperature thermal storage technologies that do not rely on concentrated solar heat.

APPENDIX B – ADVANCED NUCLEAR REACTOR SUMMARY

Liquid Metal Cooled Fast Reactors (LMFR). A fast reactor is one that contains no moderator, the material whose purpose in a conventional design is to slow down (moderate) neutrons to make fission in uranium atoms more likely. Fast reactors rely on high energy (fast) neutrons to cause fission of Uranium-238 (the largest component of natural uranium) and other heavy transuranic elements that are considered as radioactive waste in a conventional reactor. The reactor core is typically cooled by a liquid metal – either sodium or lead – as these materials have superior heat transfer properties (*WNA*, 2020a). The primary commercial use case for a LMFR is for the reprocessing of high-level radioactive waste and fissile material that could otherwise be used in a nuclear weapon. Approximately 95% of the available energy remains in used fuel removed from light water reactors. Instead of placing this spent fuel in long-term storage, a LMFR could use this material as its fuel and drastically reduce the amount of radioactive waste from the process. The GEH PRISM reactor, a 311 MW sodium-cooled SMR design, can produce up to 100x more power per unit of fuel as compared to conventional reactors and is designed to recycle 96% of the fissionable material remaining in used nuclear fuel (*GEH*, n.d.-b).

High-Temperature Gas-Cooled Reactors (HTGR). Gas-cooled reactors use either helium, CO_2, or nitrogen as a primary coolant and operate at higher temperatures than conventional reactors. The principal advantage of HTGRs are that they operate at very high thermal efficiencies (*WNA*, 2020b). Most HTGRs planned in the U.S. utilize TRISO fuel, adding an additional layer of safety protection from nuclear accidents and minimizing waste that is generated. X-energy is a developer of HTGRs and plan to manufacture a proprietary version of TRISO fuel (known as TRISO-X) to power their reactors. The Xe-100 is a 75 MW, helium cooled reactor that can be scaled with modules up to a 300 MW power plant. Designed with passive safety features, X-energy claims the reactor is "meltdown-proof" and that a facility would only require a 400-yard safety perimeter (compared to 10 miles for conventional reactors).

Molten Salt Reactors (MSR). These reactors use molten fluoride salts as coolant and operate at low pressures (normally at or near atmospheric pressures). This approach adds an additional safety margin as the coolant cannot boil away upon a loss of power. MSRs provide significant flexibility in their design; they can operate as fast reactors and with a variety of fuels (*WNA*, 2018). Although global research is being led by China, there are several U.S.-based companies developing MSR designs. Karios Power is designing a fluoride salt-cooled, high-temperature reactor (KP-FHR) that uses TRISO fuel and operates close to atmospheric pressure. The molten salt coolant has excellent heat transfer characteristics and chemical stability and has the ability to retain radioactive fission products that might be released from the fuel. The intrinsic low pressure of the reactor system eliminates the need for an expensive high-pressure containment structure. Some MSR designs have the nuclear fuel dissolved within the molten salt coolant, such as TerraPower's Molten Chloride Fast Reactor (MCFR). This reactor design operates safely at high temperatures, enabling alternative uses such as providing heat for industrial processes or thermal storage. Additionally, batch refueling without the need for enrichment or reprocessing facilities effectively eliminates weapons proliferation risks.

Microreactors. There is growing interest in microreactors (<10 MW) which are either mobile (for off-grid or backup power applications) or stationary (to provide grid flexibility) (*WNA*, 2020b). Most designs are in the conceptual stage and funded with federal government support. The U.S. Department of Defense (DoD) is especially interested in the development of mobile microreactors to provide power to military bases without the need for a fuel supply chain. In March 2020, the Strategic Capabilities Office (SCO) issued contracts to three companies, under the moniker Project Pele, for the conceptual development of a 1-10 MW microreactor that can fit in a standard shipping container and be flown on a C-17 transport aircraft (*ANS*, 2020). In addition to defense use cases, microreactors also hold promise in disaster relief functions or for remote, off-grid communities that typically used petroleum-based products for power. The Oklo Aurora "powerhouse" is a stationary 1.5 MW fast reactor with metallic fuel that is designed to power a remote community for up to 20 years. The DOE issued a site use permit to build the first Aurora plant at INL and could be operational by 2024 (*Patel*, 2020).

APPENDIX C – ELECTROLYSER TECHNICAL SUMMARY

An electrolyser consists of a direct-current (DC) source and two metal-coated electrodes, which are separated by an electrolyte. The electricity enables the transfer of ions through the electrolyte, causing gases to form at the anode and cathode electrodes. Electrolysers consist of individual cells which can be combined into stacks to scale up to larger systems.

Electrolysers are categorized by the electrolyte materials and the operating temperature of the cell. Low-temperature electrolysers (~60 - 80º C) are widely used and have been available commercially for over 100 years. High-temperature units (~700 - 900º C) are in the R&D stage but offer increased conversion efficiency and the possibility of producing a synthesis gas directly from steam and CO_2 for use in synthetic fuels production. Existing electrolyser units operate at efficiencies of approximately 60 - 80%. The primary types of electrolysers are briefly described below (*DOE*, n.d.-c).

Alkaline. Alkaline electrolysers operate via transport of hydroxide ions through the electrolyte from the cathode to the anode, with hydrogen being generated at the cathode. These designs typically use a liquid alkaline solution (sodium or potassium hydroxide) as the electrolyte and have been commercially available for many years. Alkaline electrolysers have been the design of choice for utility-scale deployments, owing to their low system costs and long lifespans.

Polymer Electrolyte Membrane (PEM). In PEM electrolysis, the liquid electrolyte is replaced with a specialty membrane that allows the selective exchange of ions through the material. Either proton exchange or anion exchange types may be used, with proton exchange membranes[12] more common in commercial applications (*Shell*, 2017). PEM electrolysers produce high purity hydrogen with flexible operation and are used in various small and medium commercial applications.

Solid Oxide. Solid oxide electrolysers use a solid ceramic material as the electrolyte that selectively conducts negatively charged oxygen ions at elevated temperatures. The oxygen ions react at the anode to form oxygen gas and generate electrons for an external circuit, which combines with water to form hydrogen at the cathode. These designs require high-temperature operation and can take advantage of this heat to decrease the amount of electrical energy needed to produce hydrogen. Solid state electrolysers are still at the experimental stage but have shown promise for certain applications.

Industrial Supplier: Nel Hydrogen, a Norway-based company, is a global supplier of both alkaline and proton PEM type electrolysers. Their alkaline units are highly energy efficient and can be scaled up to 2.2 MW per stack (over 8 tons of hydrogen per day). The PEM units provide fast response times and production flexibility, making them ideal for hydrogen generation utilizing intermittent power sources. These electrolysers can either operate in "command following" mode by scaling production based on input power (10 – 100%) or in "load following" mode by automatically adjusting output (0 – 100%) to match demand. Although the equipment does require a small amount of input power at all times, these types of designs would pair up well with the variability of wind and solar electricity production. Notably the 2 MW version of the proton PEM electrolyser only uses 99 gallons of fresh water per hour at maximum capacity, a minimal amount as compared to other uses of water (e.g. power plant cooling). Research priorities with regard to electrolysers currently include increasing the efficiency and operating life of the electrolyser system as a whole, increasing power density and stack size, reducing material costs, introducing pressurized systems to avoid the need for subsequent compression of the

[12] Proton exchange membranes are sometimes referred to by the acronym PEM, which is also used to describe the broader Polymer Electrolyte Membrane type electrolysers.

hydrogen produced, and further improving flexible systems adapted to intermittent and fluctuating power supply (*Shell*, 2017).

APPENDIX D – FUEL CELL TECHNICAL SUMMARY

A fuel cell is an electrochemical device that produces electricity and heat from a fuel source. While fuel cells can operate with a variety of fuels (e.g. methane), we focus here on hydrogen fuel cells. The construction of a fuel cell is similar to an electrolyser cell, consisting of anode and cathode electrodes sandwiched around an electrolyte. Hydrogen is fed to the anode and air (oxygen) is fed to the cathode, while a catalyst separates hydrogen atoms into protons and electrons. The electrons run through an external circuit as electricity while the hydrogen atoms combine with oxygen to produce water. Although the basic operation of all fuel cells are the same, special varieties have been developed to take advantage of different electrolytes and serve different applications (*DOE*, n.d.-a).

Alkaline. Alkaline fuel cells (AFC) use an alkaline electrolyte such as potassium hydroxide that conducts hydroxide ions. Originally developed for space applications, alkaline fuel cells are finding new applications in small-scale portable power generation.

Polymer Electrolyte Membrane (PEM). PEM fuel cells (PEMFC) use a proton-conducting polymer membrane as the electrolyte. These cells operate at relatively low temperatures and can quickly vary their output to meet shifting power demand. PEM fuel cells are predominantly used in vehicle drivetrains and can also be used for stationary power production.

Phosphoric Acid. Phosphoric acid fuel cells (PAFC) fuel cells use a phosphoric acid electrolyte that conducts protons held inside a porous matrix. Phosphoric acid fuel cells are a mature design and are typically used for large-scale decentralized power generation for buildings.

Moten Carbonate. Molten carbonate fuel cells (MCFC) use a molten carbonate salt immobilized in a porous matrix that conducts carbonate ions as their electrolyte. They are being used in a variety of medium-to-large scale stationary applications, where their high efficiency produces net energy savings. Their high-temperature operation enables them to internally reform fuels such as natural gas and biogas.

Solid Oxide. Solid oxide fuel cells (SOFC) use a thin layer of ceramic as a solid electrolyte that conducts oxide ions. They are being developed for use in a variety of stationary power applications as well as in auxiliary power devices for heavy-duty transportation. Operating at high temperatures, these fuel cells can also internally reform methane and can be additionally combined with a gas turbine to produce electrical efficiencies as high as 75%.

Regenerative Fuel Cells. A regenerative fuel cell (RFC) is a specialized type of fuel cell that is optimized to run in reverse (i.e. operating both as an electrolyser and a fuel cell). RFCs hold promise as storage deployments to renewable energy sites, where they can “absorb” excess electricity during times of high supply through hydrogen production and generate electricity during times of high demand. Wang et al. performed a review on unitized RFC technologies, a compact version of an RFC with only one electrochemical cell, that included PEM, alkaline, and solid-oxide type fuel cells (*Wang et al.*, 2016, 2017). The authors note that a reversible fuel cell system possesses distinct advantages such as high specific energy, zero pollution, and decoupled energy storage capacity with rated power. PEMFCs display superior power output and cycle stability but suffer from high cost components used for catalysts and membranes. SOFCs are available at lower cost with high roundtrip efficiencies but have lower cycle stability than PEMFCs. In general, research in this area is promising but more development work is needed to produce RFCs that are cost effective and show high performance in utility-scale applications.

Industrial Supplier: Plug Power is a U.S.-based fuel cell company that provides hardware, fueling equipment, and services for various stationary and non-stationary applications. Perhaps best known for their GenDrive line of fuel cells for material handling equipment (e.g. forklifts and pallet jacks), they also manufacture a wide range of fuel cell products for everything from unmanned aerial vehicles to backup power units. Leveraging extensive R&D efforts in recent years, Plug Power exclusively uses PEMFC in its various lines. Due to the technology's high power density, flexibility, and scalability, PEMFC units from Plug Power and other companies have achieved a dominant market share and represented 83% of fuel cell capacity delivered in 2019 (*Statista*, 2020).

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