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The impacts of the energy transition on infrastructure needs in the US

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Note: all amounts are in USD, unless otherwise stated.

Abstract

The energy sector is at the precipice of the transition to a low carbon economy. According to the Intergovernmental Panel on Climate Change (IPCC) – in order for global warming to be limited to well below two degrees Celsius above pre-industrial levels by 2050 – the world will need to achieve "net zero" emissions by the same time period.[i] The scale of the investments needed to achieve net zero emissions by 2050 cannot be underestimated. Indeed, to achieve this objective, the International Renewable Energy Agency (IRENA) estimates that approximately $195 billion of annual investments will be needed over the next two decades in the North American power sector, with 89% specifically earmarked for renewables and power grids. Against this backdrop, we believe regulated US electric utilities are positioned to benefit from the energy transition, as low carbon solutions and technology – coupled with changing regulations, policy, and consumer demands – pave the way for long-term investment opportunities.

i. Carbon dioxide is the largest contributor to total greenhouse gas (GHG) emissions, accounting for around three-quarters of total GHG emissions.

This paper explores the long-term risks and opportunities to be found in increasing renewables uptake, investments in transmission and distribution (T&D), and the ongoing electrification of the grid. We believe that regulated utilities are set to capture a substantial portion of these energy transition opportunities and are also positioned to deliver more stable and transparent returns compared to other renewable investments, such as renewable developers and "yieldcos". Importantly, and perhaps most overlooked, there are significant long-term opportunities to be realised by regulated utilities on the transmission and distribution side to support the increasing uptake of renewables, for example, by connecting customers with new renewable locations, accommodating a more complex grid, and facilitating greater electricity demand due to ongoing electrification. Importantly, these investments will be made almost entirely by the electric utilities, and support multi-decade growth in regulated asset base and regulated returns for investors, which is highly accretive particularly in a low interest rate environment. We also believe the larger electric load from electrification, and lower fuel and operation and maintenance (O&M) costs of renewables generation will allow regulated electric utilities to grow their asset base at a strong rate whilst also ensuring affordable rates for customers.

To complement this research, this paper analyses the extent to which the transition to a low carbon world and ongoing electrification is hampering the long-term outlook for regulated gas utilities and their terminal value. We explore the potential for the gas network to work in tandem with the electric network, weighing up the opportunities and practical hurdles for the network to be complemented and/or re-purposed for renewable natural gas and hydrogen. While we believe natural gas will continue to play an important role in providing heat for colder climates – where it is more difficult for electricity and heat pumps to provide the necessary energy load in a flexible and decarbonised manner – this paper finds that the outlook for gas utilities in warm and moderate climates may be more challenged. We expect the gas network will continue to play an important role in the delivery of energy in North America for multiple decades to come, particularly for harder to electrify sectors such as heavy industry and transportation; however, our research suggests its role could diminish, especially in more moderate climates where greater electrification is more feasible, and therefore impact long-term valuations for the sector.

In totality, this paper is designed to provide a balanced and constructive discussion around the risks and opportunities associated with the transformation of the US energy sector to support the transition to a low carbon world. Overall, we believe the outlook for electric utilities has improved significantly, being supported by a robust pipeline of visible investment opportunities (in both renewables generation and T&D) that we expect will enable them to grow earnings well beyond the next decade. Conversely, we believe the outlook for gas utilities remains a lot less certain, and much more dependent on unique factors and/or unproven technologies. We have put our research into practice with respect to the investment opportunities we currently see globally – as of 31st December 2020, approximately 29% of our portfolio is exposed to electric utilities, versus approximately 1% in gas utilities.[ii] This compares to 22% and 4% exposure to electric and gas utilities in the same period two years ago (31st December 2018).

ii. Gas utility exposure excludes exposure to long-haul gas transmission pipelines, as the outlook for these types of assets depends on a number of factors beyond the scope of this paper. For example, in addition to being exposed to domestic demand from industrial customers and in commercial and residential buildings (which is the predominant exposure for gas distribution pipelines), gas transmission pipelines are also exposed to demand from power generators as well as LNG export demand.

The current focus of decarbonisation in the energy sector

A brief summary of measures to-date

The global emissions challenge

Energy has played a pivotal role in the modern world, helping drive significant quality of life improvements and immense technological innovations. In developed markets today, it is considered essential to the basic functioning of society, enabling the many products and services we use daily (for example, lighting, cooking, transportation, communications, and computing). The majority of today's energy has come from fossil fuels because, historically, they have been cheap, readily available, and easy to convert into energy through combustion. As the world's population continues to grow and prosperity increases, global demand for energy will continue to rise, and meeting this demand in a safe, reliable, affordable, and sustainable way creates a wide array of new challenges.

The energy transition is about transforming the energy sector from one that is fossil-fuel based to one that is carbon-neutral by 2050, in order to combat the negative environmental impacts of climate change. The Paris Agreement objective of limiting global temperature rise to well below two degrees Celsius from pre-industrial levels calls for a reduction in global greenhouse gas (GHG) emissions to net zero by 2050.[1] In 2016, the energy sector emitted 36.2 billion tonnes of GHG emissions,[iii] representing 73.2% of total emissions.[2] As the largest contributor to emissions, deep decarbonisation of the energy sector is critical to achieving this target and therefore plays a strategically important role for society at large.

What does "net zero" emissions mean?

"Net zero" emissions refers to achieving an overall balance between greenhouse gas (GHG) emissions produced and greenhouse gas emissions taken out of the atmosphere. Getting to net zero means GHG emissions must be significantly reduced with any remaining quantities offset, for example, through afforestation or drawdown technologies such as direct air capture.

The US context

In 2016, the US accounted for around 14% of the world's energy-related GHG emissions (5.2 billion tonnes),[3] so their ability to successfully navigate through the energy transition will be extremely important to achieving global targets. In anticipation of, or in reaction to this shift, regulated US utilities companies are rapidly developing strategies centred around long-term decarbonisation goals with many targeting net zero emissions by 2050. Their energy transition is primarily being achieved through: (i) electrification; (ii) decarbonisation of electricity generation, particularly through coal-to-gas switching and renewables; and (iii) enhanced energy efficiency. Ultimately, efficient decarbonisation will require the continued deployment of current technologies, as well as new technologies including for longer-term storage solutions, giving rise to substantial long-term investment opportunities for utilities. The key challenge will be managing the energy transition whilst balancing competing factors of reliability, security, and affordability of energy together with sustainability.

> "Efficient decarbonisation will require the continued deployment of current technologies, as well as new technologies including for longer-term storage solutions, giving rise to substantial long-term investment opportunities for utilities."

Electrification

Electrification refers to the process of replacing fossil fuels with electricity as a source of energy. Given that electricity is increasingly being generated from renewable sources, increased electrification can help lower overall emissions intensity. This ongoing trend represents an opportunity for electric utilities, as firstly, capital expenditure will be required to facilitate greater electricity demand, and secondly, the increased electrification load will enable utilities to grow their asset base at a strong pace without increasing customer rates.

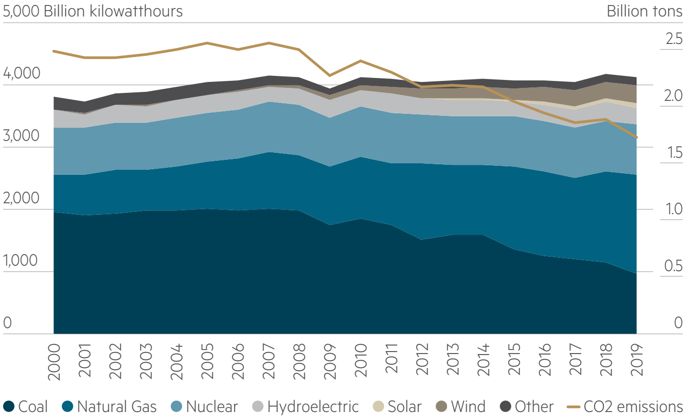
Electrification of the energy end-use sectors, namely the transportation, industrial, commercial, and residential sectors, is critical to achieving decarbonisation. In the transport sector, decarbonisation efforts have been largely focused on the adoption of battery electric vehicles (EVs) for personal transportation, driven by falling battery costs – which have decreased by over 85% since 2010 – coupled with supportive government policies (for example, in California, the governor signed an executive order requiring all sales of new passenger vehicles to be electric by 2035).[4] Though at earlier stages, electrification opportunities for other segments such as heavy-duty trucks, aviation, and shipping are becoming increasingly viable. Nonetheless, electricity only provided 1% of the US transportation sector's energy in 2019, with the vast majority (91%) of energy provided by petroleum.[5]

iii. Energy sector GHG emissions are defined by the World Resources Institute (WRI) as energy use in industry, transportation, buildings, agriculture, and fishing, and fugitive emissions from energy production.

Decarbonisation of electricity generation

Reducing the carbon intensity of electricity generation is primarily being achieved through fuel switching, particularly from coal to natural gas, and the rapid deployment of renewable energy. In the US, the share of fossil fuels in net electricity generation has fallen from 69.0% in 2009 to 62.7% in 2019, driven almost entirely by the phase out of coal.[6] By comparison, renewable energy has increased from 10.6% in 2009 to 17.5% of electric generation in 2019, the majority of which comes from hydropower and wind. These shifts have enabled a 33% decline in the electric power sector's emissions from their peak in 2007, despite maintaining a nearly identical level of electricity generated. While natural gas itself poses a longer-term emissions challenge, it continues to act as an important transition fuel with significant CO2 reduction benefits, as long as fugitive emissions (such as methane) are managed effectively. IRENA estimates that by 2050, the share of renewables must increase to 67% of primary energy supply and 85% of electricity generation in North America in order to achieve international climate goals (i.e. the Paris Agreement), led by growth in solar and wind.[7]

Figure 1: US electricity generation, by major source (LHS) and US electric power sector CO2 emissions (RHS), 2000-2019

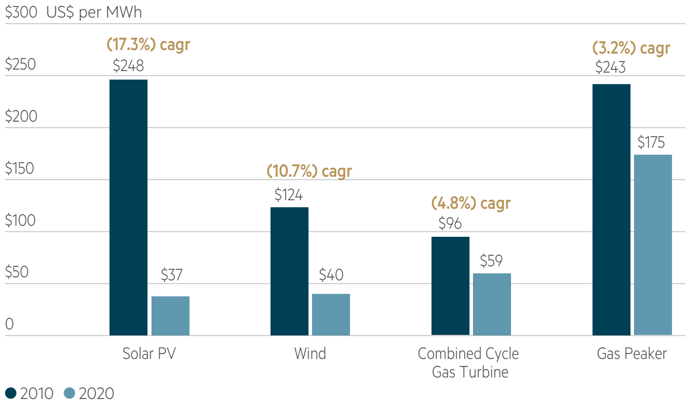


Source: EIA, 2020

The expansion of renewables has been facilitated by falling costs and improved scalability, particularly for solar photovoltaic (PV) and wind power. Over the past decade, the global weighted-average unsubsidised levelised cost of energy (LCOE)[iv] of utility-scale solar PV has fallen by 85%, from $248/MWh in 2010 to $37/MWh in 2020.[8] The unsubsidised LCOE of wind has also declined over the same period by 70% to $40/MWh, with costs for both solar and wind being slightly lower than this in the US. Indeed, renewables have become increasingly competitive with – and in some cases, cheaper than – fossil fuel-based electricity. Driven by continued improvements in technology, economies of scale and competitive supply chains, these cost reductions are only expected to continue.

Based on historical trends and Power Purchasing Agreement (PPA) prices for projects being deployed to 2030, and assuming that tax credits have ceased, the LCOE in the US is expected to achieve $25/MWh for both solar PV and onshore wind by 2030.[9]

Figure 2: Global levelised cost of energy (LCOE) from utility-scale generation by source, 2010 vs. 2020



One of the greatest challenges associated with wind and solar power is their dependency on variable sources of energy and therefore their susceptibility to intermittency – in other words, they can only provide electricity generation when the sun is shining or the wind is blowing. This variability can lead to substantial supply shortfalls that fail to match demand and pose a significant threat to the flexibility of the grid when it is more heavily reliant those resources. Certain technologies, such as lithium-ion battery storage, can help balance supply and demand over periods of time to ensure grid flexibility whilst reducing the need for additional fossil fuel generation. However, battery technologies are currently expensive and only scalable on an intra-daily basis.

Clearly, renewables provide a large investment opportunity for electric utilities, but most importantly, these investments can be made in an affordable way for customers. This is because of their high fixed costs and low operating costs, for example, they have zero fuel costs and are less labour-intensive compared to traditional fossil fuel electricity generation. Thus, a utility will see an increase in its asset base (on which it earns a return) alongside a decrease in its O&M costs when replacing traditional fossil fuel plants with renewables. With regulatory approval, utilities may increase equity earnings by shifting capital from uneconomic generation plants requiring very large fuel inputs toward plants that run on free fuel, such as solar and wind. Commonly referred in the industry as "steel for fuel", substituting "steel" in the form of new wind and solar generation, for "fuel" used in uneconomic power plants, can provide substantial operating cost savings to the utility and bill savings to customers. Reducing the fuel portion of consumers' bills can also help insulate them from fuel cost volatility and potential liabilities.

iv. The levelized cost of energy (LCOE) is used to compare the costs of different generating technologies, representing the average revenue per unit (Megawatt-hour (MWh)) of electricity generation required to recover the costs of building and operating a generating plant during an assumed financial life and duty cycle. It allows the comparison of different technologies (e.g., wind, solar, natural gas) of differing life spans, project size, capital costs, risk, return, and capacities. The figures shown represent the mid-point of the estimated high and low end range.

The impact of the US Presidential election

Climate change has been a key pillar of Biden's campaign, and so with his recent victory, we are likely to see a significant step change in climate initiatives in the years to come. While uncertainties exist as to how successful some of these initiatives will be – with legislative proposals being highly dependent on obtaining bipartisan Congressional support – the directional shift towards an accelerated cleaner energy transition is clear.

Biden has committed to re-joining the Paris Agreement and wants to put the country on a pathway to achieve net zero emissions by 2050. In order to achieve this goal, he has proposed investing $2 trillion over the next four years in climate-related initiatives to help promote decarbonisation in the transport sector (for example, to expand electric vehicle charging stations), increase energy efficiency in buildings, and achieve **net zero emissions in the power sector by 2035.**

Achieving net zero emissions in the power sector by 2035 is an ambitious goal and represents a dramatic acceleration versus current state government and utility-level targets. While it is not clear how this will be achieved, potential policy initiatives include: new legislation introducing a national clean energy standard (a broader expansion of existing state-level practices); an extension and/or expansion of existing renewables tax incentives (such as just recently occurred in December 2020 in the second round of COVID-19 stimulus); as well as the introduction of a potential carbon tax. It is worth noting that these initiatives will rely on bipartisan support across the legislative branch, and so would be more difficult to achieve in the case of a narrowly divided House and Senate, especially due to the filibuster rule. Certain legislative proposals are more likely to receive bipartisan support, such as the extension of renewables tax incentives.

Outside of the legislative branch, Biden could also rely on executive powers granted to him by the US Constitution to advance his climate agenda through existing legislation, for example, by granting greater authority to certain federal agencies. Potential actions could include: increasing the speed and quantity of federal permits being granted to offshore wind projects; tougher emissions standards for power plants and vehicles via the Environmental Protection Agency (EPA); and stricter energy efficiency standards for appliances and industrial equipment.

Overall, we believe that decarbonisation of the power sector was a trend that never relied on the outcome of the US election, but could now be further accelerated by it. State-level clean energy standards and renewable portfolio standards were already driving faster coal retirements and renewables builds, despite the prior lack of federal policy support. As the cost of renewables continues to decline, we expect this to continue driving increased uptake.

Energy efficiency

Renewables and electrification offer one part of a much bigger picture. An important means by which the grid has and continues to decarbonise is through energy efficiency measures. Energy efficiency measures have assisted in offsetting increases in energy demand and therefore reducing CO2 emissions across all sectors. Despite this progress, energy efficiency savings have declined in recent years due to faster growth in energy demand, particularly in regions with cooler winters and warmer summers, as well as structural factors that have dampened technical efficiency gains. Additionally, programs to support efficient lighting, such as light-emitting diodes (LED), have accounted for the majority of utility energy efficiency savings in the past, however, these programs are starting to shift to other technologies as energy efficient bulbs have achieved substantial market penetration.

From a utility perspective, the impact of energy efficiency initiatives is less direct. US electric utilities have spent around $6 billion annually on energy efficiencies since 2014, resulting in incremental annual electricity savings of around 27 million megawatts.[10] We expect there to be some continued capital investment opportunities, driven in part by state energy efficiency resource standards, although this is not to the scale of electrification or renewables. Importantly, energy efficiencies can help the electric utility sector with grid flexibility while minimising its environmental impact by reducing CO2 emissions.

Demand response

Demand response or demand-side management refers to changes in consumer demand for electricity usage to adjust the load profile across different times of the day. This includes load curtailment (a short-term reduction in energy use during peak times), load shifting (shifting energy-intensive activities to when grid demand is lower), and 'behind-the-meter' solutions (self-generation). These changes in electricity consumption benefit both end-users and utilities by helping to reduce costs, transmission congestion, and the need for investments in peak load power plants. Utilities can facilitate demand response in a number of ways, for example through reliability-based initiatives, pricing programs, and ancillary services, which typically offer incentives to end-users or facilitate change through technology (such as smart thermostats/meters). In the US, in 2019, the wholesale demand response capacity of all regional system operators increased to around 6% of peak demand while advanced metering reached 50% penetration.[11]

We expect demand response to be an increasingly utilised tool to manage grids effectively in a low carbon and low-cost manner. By having pools of customers who are able to dial down their demand during periods of load stress – caused either by peak load or by reduced power availability – the financial savings to the system can be meaningful. We believe this will be an important tool in achieving a reliable grid that utilises a high proportion of intermittent renewables, particularly as technology continues to improve.

"We expect demand response to be an increasingly utilised tool to manage grids effectively in a low carbon and low-cost manner"

Investment opportunities in the electric network

Renewables, transmission and distribution, and customer affordability

The global move to decarbonise creates significant investment opportunities for US electric utilities as they transition their electricity generation to renewables and invest in the grid to support new load and greater complexity. Importantly, these investments will directly impact the greenhouse gas emissions associated with the US energy sector and contribute towards the country's overall emissions reduction commitments.

Based on the policies and targets announced by countries to-date, it is estimated that average power sector investment in North America will be between $117-134bn per annum over the next 20 to 30 years. While this number is already meaningful, in order to set the energy system on a path needed to achieve the objectives set out in the Paris Agreement, annual investments would need to increase to $195-$199bn, or 49-67%, over the same period.[v,12] These numbers clearly indicate that significantly more investment in energy infrastructure is needed to support a net zero emissions trajectory. Under Paris Agreement-aligned scenarios, 51% to 55% of total investment amounts will be needed for renewables and 33% to 37% for power networks.

This disconnect is even more acute when considering how the US power sector is dominated by the private sector. By way of example, in 2017 it is estimated that 168 of 3,000 utilities in the US were investor-owned and yet served 72% of US electricity customers that same year.[13] Against this backdrop, infrastructure investors can find substantial opportunities within the privately-owned US power sector as utility companies take ambitious steps to decarbonise.

These opportunities can be highly accretive to earnings for regulated utilities. Considering the 10-year risk-free rate is near all-time lows, at approximately 0.9%, and the average Allowed Return on Equity (Allowed ROE) in the US is currently approximately 9.5% (for the nine months ending 30 September 2020)[14], the implied Equity Risk Premium is looking to be an attractive 8.6%. This premium is higher than other countries in our global listed infrastructure universe, and is a strong incentive for the sector to make substantial capital investments. The breadth of the investment opportunity coupled with sizeable allowed returns presents a number of long-term opportunities for investors looking for exposure to assets that will facilitate the transition to a lower carbon world, and at a lower volatility of earnings compared to broader equity markets.

At Maple-Brown Abbott, we do not identify any US electric utilities, at this point in time, as being purely renewable. This could change over the long-term as the electric generation component of these businesses becomes predominantly renewable, however, we expect the T&D networks within these businesses will continue to be a substantial component of their business value. Therefore, any attempt to label companies in the US energy sector as "renewables" and "non-renewables" requires a more nuanced perspective of their business models and infrastructure assets that will facilitate the low carbon transition.

What is a climate change scenario?

A climate change scenario is a data model used to explore a range of possible pathways to a low carbon world by adopting plausible socio-economic, energy, policy, and technology assumptions over certain time periods. A climate change scenario is neither a forecast nor a projection, but instead provides a description of what a future state could look like under various carbon pathways, for example; whether global warming is limited to 1.5, 2, or 2+ degrees Celsius by 2050, and where decarbonisation is smooth and coordinated, delayed and abrupt, or stifled by inertia.

As climate change is now broadly considered to be a material and financial risk, investors are increasingly using climate change models as a stress testing tool to evaluate and uncover any valuation and stranded asset risk in their portfolios. They can also assist investors with assessing the overall alignment of their portfolio with a low carbon future.

A plethora of climate transition models exist. This paper refers to assumptions modelled by the IEA and IRENA – two highly reputable bodies with distinctly different approaches to the energy transition – to provide a comprehensive and balanced perspective on the future of the energy sector.

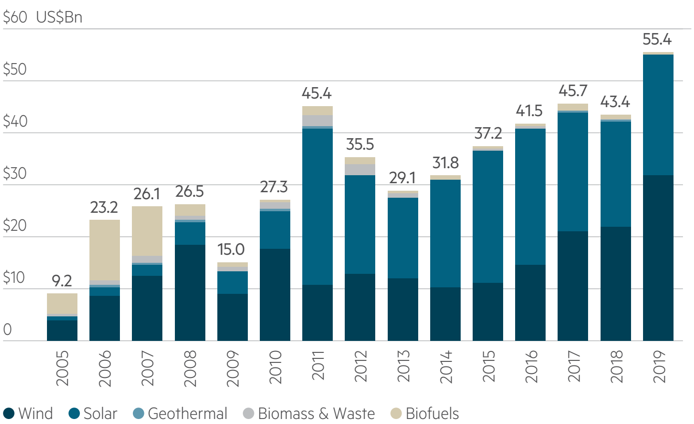
v. Figures represent the range of forecasts from the IEA and IRENA. The low end relates to the IRENA Planned Energy Scenario and IEA Stated Policies Scenario. The high end relates to the IRENA Transforming Energy Scenario and IEA Sustainable Development Scenario. IEA scenarios are to 2040 whilst IRENA is 2050, hence the range of 20-30yrs.

Investment in renewable generation

Over the past 15 years, investments in renewable energy capacity in the US have grown at a 12.7% compounding annual growth rate (CAGR), from $4.5 billion in 2005 to $55.4 billion in 2019,[15] reaching a total capacity of 265 GW.[16] As the costs of renewables have historically been far greater than conventional sources of electricity, federal tax incentives have been an important driver of this growth, including the investment tax credit (ITC) for commercial and residential projects and the production tax credit (PTC).[vi] Although the scheduled expiry of these credits in 2021 had accelerated renewable project development in 2019 and 2020, due to continued cost declines in renewables, we expect the industry will continue to grow regardless (with any further extensions of such tax credits only adding to that growth).[17] Electric utilities have also started to incorporate the impact of carbon pricing in their Integrated Resource Plans (IRPs), which are detailed documents outlining their resource needs over the next 10 to 20 years. This will only serve to increase the LCOE of conventional fossil generation, and further decrease its cost competitiveness relative to renewables.

From a policy and regulatory standpoint, 29 states and the District of Columbia have renewable portfolio standards, which require a certain portion of the state's electricity mix to be low- or zero-carbon, while 23 have their own GHG emissions reduction targets.[18] Investor-owned utilities have also made considerable inroads in recent years, with more than 30 utilities committing to 80-100% clean energy or renewable portfolio standards (RPS) before 2050.[19] The combination of these factors creates a strong tailwind for renewables and power grids investments. According to S&P Global Market Intelligence's forecasts, state RPS requirements alone will drive 6 GW to 9 GW of renewable capacity additions per year through 2030.[20] In light of the outcome of the 2020 US election, a Democrat Presidency elect will likely accelerate the pace of these changes (for example, through continued extension or even expansion of renewable tax credits). Other forms of support could come through additional R&D investment and through more renewable energy-friendly government agencies and regulations.

Figure 3: US investment in renewable energy capacity by type, 2005-2019



Source: Bloomberg NEF, 2020.

vi. The ITC is claimed against the business tax liability of the company that develops, installs, and finances the project. Commercial or utility-scale projects must begin project construction by the expiration date of the credit and place it in service within four years to be eligible. The ITC was set at 30% for projects that commenced construction in 2019 and 26% for 2020. In December 2020 it was extended for two years at 26% (for projects starting construction in 2021 or 2022), and then steps down to 22% for 2023 and 10% for projects that start construction in 2024 or later. Projects must be placed in service before 2026 to qualify for more than a 10% ITC. The PTC is a per-kilowatt-hour (kWh) tax credit for electricity produced using qualified renewable energy resources, and was to expire on January 1, 2021. It was extended in December 2020 for one year at a 60% level (of the maximum credit amount) for projects that start construction in 2021. The credit can be claimed for a 10-year period once a qualifying facility is placed in service, with the maximum credit amount for 2019 being 2.5 cents per kWh. The maximum credit rate, set at 1.5 cents per kWh in statute, is adjusted annually for inflation.

vii. EIA data is collected monthly on a survey basis, with respondents including electric utilities, generators and sellers of electricity, and the NERC.

Batteries and energy storage

As the use of variable renewables increases, energy storage solutions are becoming increasingly critical to countering intermittency and providing energy system flexibility. Over the past decade, innovation in battery cells, improving efficiencies, and a maturing supply chain have enabled the costs for battery storage to fall rapidly. Currently, lithium-ion batteries are the least expensive and most widely used battery technology, with 1.2 GWh of large-scale battery storage in operation in the US as of 2018. Since 2010, the costs for such battery packs have fallen by 87% for EVs, and around 66% for stationary applications including electricity grid management.[21] Data from the EIA indicates a pipeline of 6.7 GW of storage project installations in the US through 2023, implying a cumulative ~8 GW of additional capacity, though the majority of projects are of smaller scale (~50 MW).[vii]

Battery developments continue to be driven by the electrification of transport, with the market for EV batteries ten times greater than that for grid-scale batteries.[22] We expect further technological developments and cost reductions in EV batteries will be important in providing spill over benefits to energy storage for stationary applications, particularly as EV applications become industrialised. This is exemplified by a strong overlap in the applications of battery patents, with the IEA finding that nearly 90% of battery pack international patent families (IPFs) for stationary applications are also relevant for automotive applications.[23] Policy is also an important driver of battery adoption, with seven US states adopting battery storage targets to date.

Despite its development, lithium-ion battery technology is currently limited to short duration applications of around four hours, and its costs are not expected to fall to levels where it becomes economical for scaled-up, long-duration storage. Moreover, lithium-ion batteries carry a fire risk, and their storage ability degrades over time, necessitating alternative solutions for stationary applications.

Overall, battery developments present both an opportunity and a risk for electric utilities. Improvements in utility-scale storage will increase the effectiveness of renewables by providing a means to manage their intermittency and enhance grid flexibility, absorbing surplus power generation capacity during low-demand hours. In the case of vertically integrated utilities, these investments could be added to the rate base and earn a regulated return. On the other hand, improvements in behind-the-meter storage could result in increased adoption of distributed energy resources from customers, which could decrease utility revenues. Nonetheless, continued research and development in storage technologies will be critical to ultimately complement other technologies in providing energy system flexibility.

As highlighted earlier in the paper, the improving economics of renewables significantly over the last decade has, and continues to, stimulate strong growth in the sector. There are two main ways to gain exposure to this growth within the global listed infrastructure universe: firstly, by investing in regulated utilities that are allowed to earn regulated returns on these investments; and secondly, by investing in commercial renewables developers that earn unregulated returns.

Regulated utilities may increase equity earnings by shifting capital from traditional generation plants – which require sizeable fuel inputs – towards low carbon technologies, such as solar and wind power, that benefit from having zero fuel costs and relatively low operating and maintenance (O&M) costs. This represents a compelling opportunity for investors, as it increases the size of the asset base that utilities earn a regulated return on. For instance, in an effort to reach its goal of 8GW of regulated renewable capacity by 2030, AEP plans to invest $2.8 billion on regulated renewables between 2021 and 2025, on which it is currently allowed to earn an attractive ~9% ROE on this new investment.[24]

Commercial renewable developers are also well positioned to benefit from the ongoing growth in renewable power additions, however, we often find these business models lack transparency and face pressure from increasing competition. Under Power Purchase Agreements (PPAs), the power generated by renewable assets is contracted at a specified fixed price that can be indexed to inflation. From our experience, commercial renewables developers typically target returns in excess of what they would receive on regulated investments, for instance, as part of their commercial renewable business, NextEra Energy (NEE) – whose business is a combination of both regulated utility and commercial renewables – is known to have quoted levered internal rates of return (IRR) in the "high teens to mid-20s" for its wind assets, and "mid-teens" for solar. Whilst these numbers seem attractive at face value, the returns are highly dependent on an array of assumptions around gearing, electricity prices after the PPA expires, and residual value. Average PPA lengths have also generally been declining, and so for an asset with a 30 to 35-year life, this translates a larger proportion of uncontracted value that is dependent on merchant electricity prices, which are notoriously difficult to predict. As competition for commercial renewable assets continues to increase, we also expect commercial developer returns to be commensurately compressed. Anecdotally it appears that this is already rapidly occurring.

Case study: American Electric Power (AEP)

AEP is a regulated US electric utility serving approximately 5.4 million customers across 11 states. It owns the country's largest transmission system – more than 40,000 miles – which is more 765-KV extra-high voltage transmission lines than all other US transmission systems combined. AEP plans to invest $2.8 billion on regulated renewables between 2021 and 2025, with a goal to increase regulated renewables energy capacity by 8 GW by 2030. Moreover, AEP has committed to reducing its carbon emissions by at least 80% by 2050 and has established a timeline to decommission its coal-fired power plants to support this goal. AEP is strategically important to facilitating the US transition to a low carbon economy due to the scale and regulated nature of its assets.

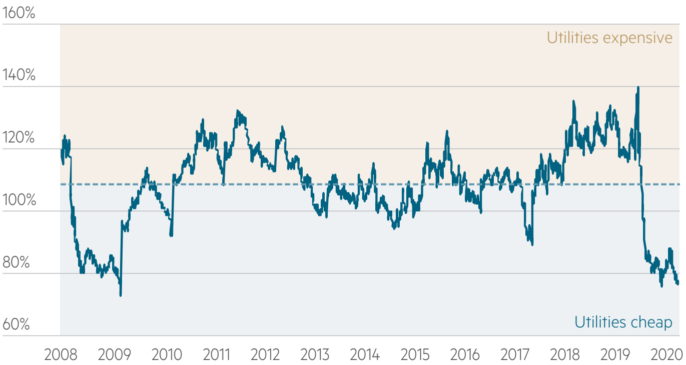
In considering the relative investment opportunities between regulated utilities and commercial renewables businesses, we believe that key factors to consider are (a) the likely market share of the renewables' development and ownership that they will each secure, and (b) their comparable valuations.

In relation to the market share of renewable developments, we believe that the growth in renewable investments will be of such scale that there will be plenty of growth opportunities from renewables for both regulated electric utilities and commercial renewable businesses. We expect that regulators will often seek some level of commercial ownership – to encourage competition in the delivery of these assets – but in most cases regulators will also see the value of the regulated utility owning a significant portion of the renewable assets, due to the network benefits and optionality that can accrue to customers by these assets being owned, and thus fully integrated, within the broader network.

From a valuation perspective, we note that there has been a stark divergence between the stock performance of commercial renewable stocks – which are commonly viewed as "renewables" – and regulated electric utilities. For example, the 2 leading utility-scale US solar manufacturers saw stock price increases of +77% (First Solar Inc) and +402% (SunPower Corporation) during 2020, and renewables focussed "yieldcos" were up +51% on average for the year.[viii] In contrast, US utilities were down approximately 8% on average for the year[ix].

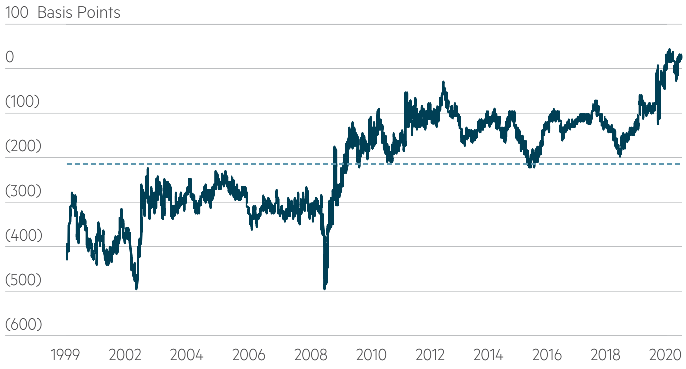
As a result of these strong stock performances, the yieldco and solar renewable companies are generally trading at historically high valuation multiples. In contrast, the regulated utilities are trading below their historical averages. For example, the first chart below shows that over the last 12 years, US regulated utilities have on average traded at a 8% premium to the S&P500 from a price to earnings perspective, yet today is trading at a 22% discount. Similarly, the second chart shows that whilst utility dividend yields have on average been more than 210bps *below* the Baa corporate bond yield, today the dividend yields are slightly *above* that bond level.

Figure 4: US utilities vs S&P 500 (forward P/E)



Source: FactSet.
Data as at 31 December 2020. Past performance is not a reliable indicator of future performance.
Note: Utilities = MBA GLI Focus List North American regulated utilities.

Figure 5: US utilities dividends vs Baa corporate bond yields (yield spread)



Source: FactSet, Bloomberg.
Data as at 31 December 2020. Past performance is not a reliable indicator of future performance.

And finally, there are a range of reasons why the commercial renewable developers generally do not currently fit within our investment philosophy, including:

- We find that the structured nature (e.g. limited partnerships) of some of the commercial renewable companies can create corporate governance and/or financial leverage challenges.
- The solar renewable companies are predominantly developers, and not long-term owners, of their infrastructure assets; and
- The small proportion of listed pure-play companies holding utility-scale renewable assets are mostly small-cap companies or not of investment grade credit quality, such as "yieldcos"[x], and therefore have restricted investment eligibility for asset managers.

For all these reasons, at this point in time, we see more compelling opportunities to participate in the renewable investment opportunity through regulated electric utilities, and not through commercial renewable companies.

viii. Yieldcos include: NextEra Energy Partners LP (NEP), Clearway Energy Inc (CWEN), Atlantica Sustainable Infrastructure plc (AY), and Brookfield Renewable Partners LP (BEP).
ix. US utilities refer to North American regulated utilities on the MBA GLI Focus List.
x. Yieldcos are companies set up to own operating-stage renewable energy companies, and to return the great majority of cash flows to investors.

Regulated investments in transmission and distribution

In addition to the investment opportunity on the generation side, the energy transition also depends on large investments in electric transmission and distribution (T&D). Network investments help support the expansion of renewable generation and also increase overall system reliability, and so will be pivotal in enabling effective decarbonisation. Additional transmission investment is required to connect new renewable locations and provide better interconnectivity between regions to help address intermittency, while distribution investment is required to address greater grid complexity and facilitate demand response. The IEA estimates that approximately 30% of the increase in transmission lines and 20% of the increase in distribution network lines globally through 2030 will be attributable to the increase of renewables.[25] We expect these investment opportunities to be significant, and unlike renewables investments which face greater competition, it is expected that investments in T&D will predominantly be made by the US electric utilities.

> "The energy transition depends on large investments in electric transmission and distribution (T&D)"

Investments in zero-carbon energy generation must be accompanied by large investments in electric transmission networks to prevent congestion and curtailment issues. A recent example of this is California, where 1,464 GWh of wind and solar generation was curtailed during the months of January to October 2020, and 70% of such curtailment was due to local transmission constraints, illustrating the importance of having the right level of transmission infrastructure to prevent unnecessary wastage of renewable capacity.[26] Accordingly, these investments are key to accommodating the variability of renewable power and enabling their mass deployment. This is particularly true for wind in the US, as wind farms are often built in remote areas, whereas solar power can typically be built closer to demand centres.

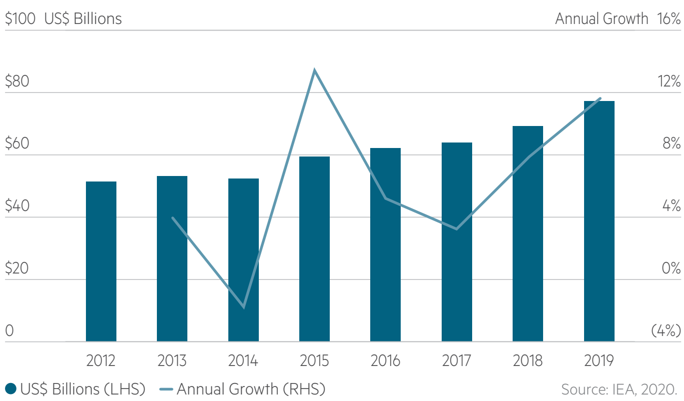
Continued investments in distribution networks will also be required to support network resilience and reliability, as well as systems improvements such as modernising and digitalising the grid. Replacing old lines with new equipment (also known as "hardening" the grid) has become increasingly important to secure the grid against adverse catastrophic events such as natural disasters, storms and cyberattacks, and provide resilience against other physical risks from climate change. The grid has also become more complex with multi-directional electricity flow, creating additional challenges in balancing the grid. In this context, the expansion of distributed generation will necessitate further investments, as smarter grids are needed to integrate technologies and ensure interconnectivity between energy generation, storage and end users. Going forward, we expect these investment opportunities will allow electric utilities to grow their asset base and support earnings growth in the future.

> "To meet existing energy and emissions-related policy commitments, the IEA forecasts that 3.3 million kilometers of electricity network lines will need to be built or replaced in the US through to 2030."

Grid investments in the US have stepped up materially over the past decade, growing by 11.6% year-on-year to reach $77 billion by 2019.[27] The IEA forecasts that 3.3 million kilometres of electricity network lines will need to be built or replaced in the US through to 2030, with the majority being distribution lines, to meet existing policy commitments accounted for in the Stated Policies Scenario. We expect considerable levels of T&D spending to continue, both to ensure reliability and to cater for the shift in the nation's generation portfolio toward renewables and distributed energy resources. For instance, Duke Energy's (DUK) current five-year grid capital expenditure plan (2020 to 2024) consists of $17 billion of investments in distribution and $7 billion in transmission, out of a total $58 billion. These investments are material, particularly given the company's $70 billion market capitalization, and constitute a significant portion of the company's total capital expenditure and therefore its future rate base and earnings growth.[28] Even more pronounced is that AEP 2021-2025 capital forecast includes $10.6 billion (33%) of spending on distribution and $16.1 billion (49%) on transmission, equating to 60% of the company's market capitalisation, compared with $2.8 billion (8%) on regulated renewables and $2.1 billion (6%) on contracted renewables.[29] This capital expenditure will contribute to substantial growth in regulatory capital employed for US utilities, for example, 6.5% p.a. over 5 years for DUK and 7.4% p.a. over 5 years for AEP, which we expect will drive attractive future earnings growth.

In our opinion, electricity transmission and distribution network owners are favourably positioned to benefit from the transition to a low carbon economy. We find the regulated returns that they receive on these investments to be stable and predictable and provide an attractive risk-adjusted return. And as shown in the previous section, we view the valuations of regulated utility companies to be below their historical averages, notwithstanding the very significant investment opportunity that we believe will accrue to them as a result of the energy transition.

Figure 6: Investment in electricity networks in the United States, 2012-2019



Source: IEA, 2020.

Other new and old storage technologies

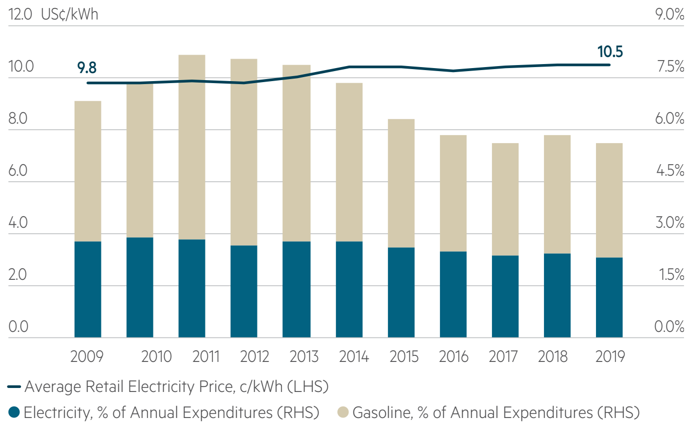
- **Mechanical energy storage systems** store energy using kinetic or gravitational forces via systems such as a flywheel, pumped hydropower, and compressed air (CAES). These systems generally have low costs per kilowatt hour and long lifetimes, and offer a long-dated storage solution.[30] Pumped hydro is the most prevalent energy storage technology today, representing over 97% of large-scale storage capacity in the US.[31] These facilities store energy in the form of water, which is pumped from a lower reservoir to one at a higher elevation using electricity during off-peak times. However, new capacity development has been near non-existent for over a decade, being impeded by high capital costs and a lack of suitable sites given they occupy large areas.[32]
- **Redox flow batteries** are rechargeable electrochemical systems, emerging as a new technology that offers significant potential for long-duration storage at low costs. Key advantages include decoupled power and energy scaling, long operational lifetimes with deep discharge capabilities, simplified manufacturing, and improved safety characteristics.[33] During 2019, a redox flow developer, Form Energy, secured funding of $40 million and announced a 150 MWh aqueous-air battery project in the US.[34]
- **Hydrogen** is an energy carrier that can store electricity in chemical form via the process of electrolysis. This involves splitting water into hydrogen and oxygen gas using devices known as electrolysers, which are powered by renewable energy. The hydrogen can then be stored for indefinitely and at a large scale, before being converted back into electricity via a fuel cell, which carries out the inverse process to electrolysis. Producing hydrogen during periods of high wind/solar availability would allow a reduction in renewables curtailment, and make hydrogen available during periods of high demand. Hydrogen can be stored in salt caverns or in repurposed depleted oil/gas fields, though the former has limited geographic availability, while the latter has greater risk of contamination. Alternatively, hydrogen may be stored as liquid ammonia in ammonia storage tanks. Those currently used in the fertilizer industry have over 1,000 times greater capacity than lithium-ion battery storage available today. An additional consideration is that the process of converting hydrogen back into usable electricity results in a 60% loss of original electricity (including loss of energy from transportation, storage, and waste heat during conversion), and therefore will only be viable for long-durations where batteries and other storage options are not available or economical (particularly given stored electricity loses power over time, while hydrogen does not).
- **Thermal energy storage systems** store surplus energy as thermal energy by heating or cooling a storage medium, with the ability to store energy for longer periods (days to months) and dispatch it on demand. These systems benefit from low costs and operating flexibility, however they have relatively low efficiency and suffer thermal standby losses between the storage medium and environment.[35]

Ensuring the affordability of electricity

Amid a clear need for investment in the electric network and renewables, the key concern remains whether this can be done affordably. Over the last two decades, electricity demand and electricity prices have remained relatively flat, as increases in demand, driven by both population growth and new use-cases, have been offset by improvements in energy efficiency and technology. More importantly, average utility bills in the US have decreased as a percentage of household income and household expenditure over the last decade. According to the Consumer Expenditure Survey conducted by the U.S. Bureau of Labor Statistics, electricity constituted an average 2.3% of annual expenditure by US households in 2019, compared with 2.8% in 2009.[36] By comparison, gasoline expenses for transportation dropped from 4.0% in 2009 to 3.3% in 2019. As sectors – particularly transport – continue to electrify, customer spending on gasoline will diminish and eventually be replaced by electricity. In this way, while we expect that electric bills will take a larger share in household bills, the overall costs for households can remain flat. Furthermore, investments in renewables as regulated assets allows utilities to increase rate bases without a corresponding increase in bills due to eliminating fuel costs and lower O&M costs. Therefore, we believe the combination of a larger electric load from electrification with the low variable costs of renewables will allow electricity to remain affordable, notwithstanding long-dated capital expenditure programs that will support strong, long-term rate base growth.

> "We believe the combination of a larger electric load from electrification with the low variable costs of renewables will allow electricity to remain affordable, notwithstanding long-dated capital expenditure programs that will support strong, long-term rate base growth."

Figure 7: Average US retail electricity price (¢/kWh) (LHS) and proportion of average annual spending on electricity and gasoline (%) (RHS)



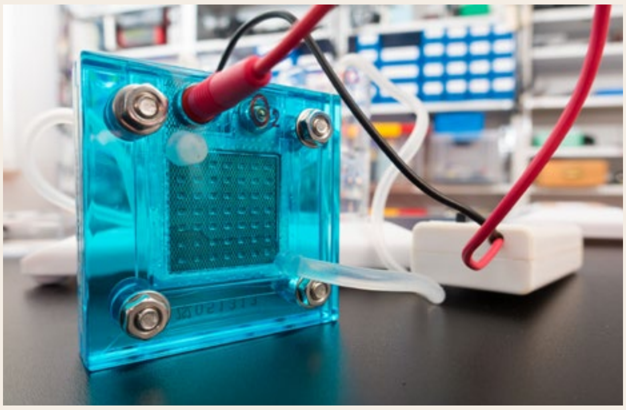
Source: EIA, 2020; U.S. Bureau of Labor Statistics, 2020.

Risks for utility-scale electric systems

Advances in technology and the growth of distributed energy generation and demand response solutions introduce new choices for customers but represent a potential risk for electric utilities. Continued innovation around "behind-the-meter" generation and storage mean that customers can go "off grid", in other words, they can generate electricity themselves without being connected to the main grid. However, there are barriers to going off grid around affordability and reliability for customers. For instance, renewable energy is far cheaper to generate at utility scale than as distributed generation due to the efficiencies of scale. In the US, the LCOE of rooftop commercial and industrial (C&I) solar PV systems was $107/MWh in 2019, which is substantially higher than utility-scale solar at $29/MWh.[37] It also makes more sense to build wind farms and solar panels where the wind blows strongest and the sun shines hardest. While this may vary due to seasonality, generation at utility-scale that can be moved between regions (based on where capacity factors are highest) represent a key benefit to being connected to the grid. While this provides utilities some protection from distributed generation taking substantial market share, which accounted for just 2% of US electricity generation at the end of 2019, some large C&I customers who can generate renewable energy efficiently are increasingly utilising behind-the-meter solutions.[38]

Overall, provided electricity continues to be priced at an attractive rate, we believe that most customers will continue to pay for the reliability of being connected to the grid. The increasing shift to electrification will increase volumes (notwithstanding offsets from energy efficiency), and so will enable electric utilities to continue to offer a competitively priced and valuable commodity to customers. Considering these factors, we believe there is a relatively low risk that electric utility investments become stranded assets, although we continue to closely monitor any technological changes that may impact this.

Fuel cells



Fuel cells are an advanced conversion technology that converts fuel chemical energy directly to electricity and heat by electrochemical reactions, with higher energy efficiency and lower emissions than energy produced from combustion. While most often powered my hydrogen, these systems are able to operate on a range of gaseous fuels, including natural gas, and renewable fuels such as biogas. With neither carbon emissions nor air pollutants, hydrogen-powered fuel cells are increasingly recognised as an important technology to help achieve deep decarbonisation.

While particularly strong growth has been seen in transport applications, fuel cells offer potential for stationary power applications, offering an alternative to traditional power generation. Here, fuel cells can provide a reliable and immediate source of backup power for hours to days, similar to a battery though being able to generate power indefinitely given the availability of a fuel source. This can be helpful to utilities, providing reliability and a means to mitigate the intermittency of variable renewables. Hydrogen-powered fuel cells can generate electricity with up to 60% efficiency, compared with conventional combustion-based power plants at around 35%. The US currently has over 550 MW of large-scale fuel cell systems in place, primarily for stationary power generation. The reaction also produces heat as a by-product, making fuel cells particularly useful for combined heating and power applications such as water heating (otherwise, the heat is wasted). Furthermore, fuel cells have the potential to allow natural gas to be used in energy systems with lower emissions. However, large-scale adoption of fuel cells remains challenged by high costs.

The role of gas networks in the energy transition

Will gas distribution networks become redundant?

Natural gas has played a substantial role in reducing CO2 emissions in the US to date. This is because it is a reliable, readily available source of energy, and a relatively clean alternative when compared to other fossil fuels (particularly when burned for energy). Compared to coal, natural gas is estimated to emit half as much carbon dioxide when burned for fuel, however, this ignores the impact of methane leaks. Methane leaks that occur along the gas supply chain are significantly more potent than CO2 emissions, with estimates suggesting they are around 20 times more powerful over 100 years. It is therefore now becoming more widely accepted that fuel-to-gas switching on its own will not provide a long-term solution to mitigate the rate of climate change. In addition to the environmental impacts, there are also some longer-term affordability concerns around whether decarbonised forms of gas, such as Renewable Natural Gas or hydrogen, can remain cost competitive versus electric, particularly in more moderate climates. Whilst the outlook for gas networks, or Local Distribution Companies (LDCs), looks robust for the coming decades, we believe that the very long-term outlook has become uncertain, and the risk of certain assets becoming stranded has increased.

We reflect this level of uncertainty in our valuations, in which we assign a higher probability to scenarios in which gas networks will ultimately exhibit much lower growth rates. However, we also recognise that there are certain applications in which natural gas will continue be useful. To understand why this might be, it is important to understand some of the key benefits gas systems, which currently provide: (i) reliability; (ii) effectiveness as an energy delivery system, especially in colder climates; (iii) low cost; and (iv) high heat rates making it more suitable for certain harder-to-electrify areas, such as heavy industrial or transport purposes.

Current benefits of gas networks

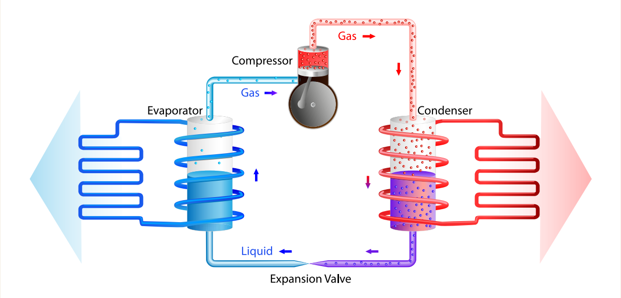
Reliability is critical – particularly as energy generation and consumption patterns change over time, such as with increasing working from home practices. As electricity is challenged by its peak load capacity, its susceptibility to intermittency, and a lack of affordable and scalable energy storage solutions at this point in time, natural gas infrastructure remains critical energy infrastructure for most of the country. On average, electric systems in the US have one outage per year per customer, which in 2018 lasted an average 5.8 hours,[41] while gas networks have one outage per 112 customers and for unplanned outages this is one in 800 customers.[42] The electricity network is also exposed to greater physical climate-related risks being predominantly above ground, causing most electric distribution outages to occur due to unplanned impacts such as severe weather. This was recently seen in California, where exceptionally high electricity demand coupled with generation outages during a heat wave in August led to the implementation of rolling blackouts, with as many as two million customers suffering a loss of power. Underground natural gas networks on the other hand have proven more resilient, with the majority of natural gas outages occurring due to planned maintenance.

> "Gas distribution networks face greater risk in warmer and moderate climates due to less demand variability relative to cooler climates, and so there is potential for the electric system to suffice on its own in certain instances."

Heat pumps

Heat pumps are systems that use electricity to move heat from a cool space to a warm space, making the cool space cooler and the warm space warmer. These devices move thermal energy in the opposite direction of spontaneous heat transfer, absorbing heat from one space and transferring it to another using a compressor pump and conductor coil. Heat pumps vary in type depending on the source from which heat is collected, primarily being through the air, water, or ground (geothermal). Since 2008, federal tax credits have facilitated installations of heat pumps throughout the US, with 40-50% of newly constructed buildings installing heat pumps.[39]

By moving heat rather than generating it, heat pumps offer very effective and sustainable forms of heating, with low carbon footprint and energy efficiency gains ranging from two to four times higher than conventional heating systems. This is particularly true in warmer climates, where heat pumps have a coefficient of performance of approximately 4x. As a result, heat pumps are increasingly recognised as a means to efficiently electrify space and water heating, replacing fossil-based technologies, and thus decarbonise. For electric utilities, heat pumps can also provide grid flexibility, providing demand response through peak shaving, load shifting and energy conservation, especially when combined with thermal energy storage devices.[40] Heat pumps do, however, become less efficient in colder climates, particularly when temperatures are below freezing. This is where we expect natural gas networks to continue to play an important role in providing heat, where the electric network and heat pumps may be less effective and reliable.



The gas network is also able to deliver a far larger volume of energy than electric networks, especially in cold climates. For example, a study by environmental consultant E3 of Northwest Natural (NWN) found that on cold days, the company's gas system supplies about 90% of the energy that is going into households.[43] A recent UK report also found the gas network provides five times the energy content on peak days as the electric network does.[44] With a greater ability to remain operational during extreme weather events and in colder climates, we expect gas networks to play an important role in providing heat on very cold days where the electric network or heat pumps are unable to. Emerging technologies, such as hybrid electric heat pump and gas boilers, offer demand response solutions, and could offer a pathway that enables the electric and gas systems to work together in cold climates so to optimise the objectives of clean, affordable and reliable heat (for example, electric heat pumps used for most heating, except switching to the gas boiler on the coldest days). Considering these factors, we believe the gas distribution networks face greater risk in warmer and moderate climates due to less demand variability relative to cooler climates, and so there is potential for the electric system to suffice on its own.

Another advantage of gas distribution infrastructure is that it is much cheaper than electric infrastructure. In the US, in our experience the rate base per customer for the gas distribution network is typically less than half what it is for the electric network. Thus, from a pure infrastructure perspective, as a delivery mechanism the gas network can provide more energy with greater reliability and at a cheaper cost relative to the electric network, while providing an energy storage function that the electric network does not.

Finally, while electrification remains central to broader decarbonisation efforts, certain applications remain difficult or even impossible to electrify at this point in time and hence require other low carbon alternatives. For instance, long-haul shipping and aviation, and heavy industry requiring very high heat rates (for example, steel, cement, and glass) face substantial technological and/or financial barriers to electrification. McKinsey & Co. forecasts that most alternative electrification technologies (for example, cold climate air source heat pumps) will not economically break even on a total cost of ownership basis until at least the early 2030s.[45] Here, natural gas infrastructure may play an important role as it not only represents a low cost and lower carbon solution compared to other fossil fuels in the short term, but more importantly, it can connect these sectors with low carbon technologies such as hydrogen as the gas supply evolves.

> "We believe stranded asset risks for gas networks could be moderated by the need to work in tandem with the electric network to ensure grid flexibility and reliability."

In considering all the factors above, we believe the gas LDC networks will continue to play a broad role for probably several decades, but then beyond this timeframe is at risk of being reduced to more targeted applications. Firstly, we believe they could continue to serve certain industrial and transport purposes which are harder to electrify, although, as technologies improve – this could also diminish away over time; and secondly, we believe that there is a greater likelihood that they be used to manage peak demand periods in colder climates.

Continued electrification will substantially increase peak electricity demand for many utilities, which is already challenged by the intermittency of renewable generation. In this context, we believe stranded asset risks for gas networks could be moderated by the need to work in tandem with the electric network to ensure grid flexibility and reliability. As we have noted, networks in colder climates appear to be better positioned from this perspective. Similarly, in our opinion regulated utilities with both gas and electric networks (known as "multi-utilities") face lower risks to their gas networks than gas only network owners, given the ability and incentive for multi-utilities to manage their networks and energy needs together.

Opportunities for gas networks to decarbonise

While there are substantial uncertainties around the future for gas networks, technological advancements are opening up pivotal opportunities for gas networks to decarbonise and potentially be repurposed. The potential role of gas networks in managing peak demand and hard to electrify applications could be achieved through natural gas, renewable natural gas or hydrogen, presenting an opportunity for gas networks to assist the energy system decarbonise whilst balancing environmental outcomes with the affordability and reliability of energy. We note these opportunities come with substantial risk and uncertainty, however, it does give rise to a dilemma for investors. In scenarios where gas networks are successfully re-purposed and continue to remain useful, they will enjoy continued growth through material opportunities to invest in upgrades, expansion, and safety. We explore two possible opportunities below, and highlight the main challenges associated with each, which primarily revolve around cost and safety.

A third opportunity, which we have not explored in detail, but which is gaining increased discussion in some north-eastern states is for heating to be provided through district heating networks. This has occurred extensively in Europe over a number of decades. The gas LDCs in the US appear the most logical party to build and operate such systems, considering that they have the expertise to do so, and as it would facilitate a smooth transition of their customers and workforce from gas to district heating. A key question from our perspective is whether such networks can be economically viable in the US context.

Renewable natural gas (RNG)

Today, RNG represents only a minute portion (<0.1%) of total US natural gas supply, and is primarily used as a transport fuel. With challenging economics and supply constraints, production continues to be largely supported by California's Low Carbon Fuel Standard (LCFS) and the federal Renewable Fuel Standard (RFS). However, as demand and emissions reductions targets expand, gas companies may be incentivised and increasingly willing to support production in order to decarbonise. RNG may be particularly useful for reducing the emissions footprint of gas where full electrification is not feasible. Here, companies may offer RNG to customers for a fee, essentially passing on the higher costs of RNG. For instance, SoCalGas, a subsidiary of Sempra Energy (SRE), filed a request with the California Public Utilities Commission (CPUC) in 2019 to allow customers to opt-in to purchase RNG for an additional tariff.

Fundamentally, RNG is challenged by its high costs, which are influenced by the type of project and applicable incentive structures. Additionally, only a fraction of RNG is currently injected into pipelines and distribution networks for other end-use sectors, with most being produced and consumed on site for power generation. Here, the benefit for gas networks and end-users may not be significant, as most credits today focus on RNG in transportation fuels. It is also unclear whether RNG can make a meaningful environmental impact without compromising affordability, given these challenges and the continuing potential for methane leakage.

The environmental benefits of RNG are also very project specific – for example the most widely available form of RNG is landfill gas, but this gas is generally already captured and either flared or used for power generation. As such, the benefits from landfill RNG are not as great as say agricultural-based RNG, where the methane would otherwise have been released to the atmosphere. These other types of RNG are generally smaller scale and more expensive than landfill RNG.

Accordingly, while RNG may be a part of the holistic package of solutions to support the energy transition, its ability to play a major role in the decarbonisation of the gas networks appears questionable.

What is renewable natural gas (RNG)?

Also referred to as biomethane, RNG is the gaseous by-product of the decomposition of organic matter, which can be used interchangeably with conventional natural gas in gas networks. In the US, biogas is produced via anaerobic digestion primarily from landfills, as well as some livestock farms and wastewater treatment centres. By using methane from these waste streams that may otherwise be emitted to the atmosphere, RNG has the potential to be carbon neutral or even carbon-negative in some cases. Here, as methane is 20 times more potent than CO2 over a 100-year time period, using a small amount of methane in RNG, such as 10% RNG blended with 90% conventional natural gas, can potentially offset the GHG emissions footprint.

Hydrogen in gas distribution networks

Another proposed solution to decarbonise the gas grid is by blending, or eventually replacing, methane in existing natural gas distribution networks with low carbon hydrogen. Hydrogen can be stored and transported at high energy density, and combusted or used in fuel cells to generate heat and electricity while producing zero emissions at point of use. This represents a significant opportunity for the gas network and end-users to decarbonise, particularly in applications that are difficult to electrify. Moreover, building dedicated distribution pipelines for hydrogen would be more expensive than using existing natural gas pipeline infrastructure. In the US, large-scale infrastructure for hydrogen delivery currently only includes around 1,600 miles of hydrogen pipelines, located in select regions.[46] This compares with the country's natural gas pipeline network, which extends over three million miles and is highly integrated throughout the country.[47] Here, the use of natural gas networks could provide an economic means of transportation and storage for hydrogen while simultaneously offering decarbonisation potential, thus representing an opportunity for the long-term use of gas infrastructure and alleviating some risks for gas networks. For instance, a European study estimates that €40 billion of investment is needed by 2040 to reconfigure gas networks to deliver hydrogen across Europe, with 75% of the network reliant on existing gas transport infrastructure.[48]

Accommodating hydrogen in the gas grid is met with an array of challenges due to its distinct characteristics. For instance, hydrogen has an embrittling effect on steel, complicating its use in those gas distribution networks that are made of steel. The ability of utilities to blend hydrogen will depend on specific infrastructure and end-use characteristics, which will need to be thoroughly assessed on a case-by-case basis to determine acceptable levels of hydrogen blending.

Hydrogen – a primer

As a highly versatile and abundant energy carrier, hydrogen is likely to play a major role in the energy transition. Hydrogen is not a source of energy but an energy carrier, which stores energy that can be restored by either combusting it or chemically - using fuel cells. Hydrogen can be produced through various processes, and the method and source of energy used define whether it is considered "grey", "blue" or "green" hydrogen.

- **Grey hydrogen** is produced from fossil fuels, or electricity generated by fossil fuels, via carbon intensive processes such as steam methane reforming and coal gasification. Grey hydrogen is currently the least expensive method, and represents approximately 95% of the total hydrogen produced today, primarily produced from natural gas.
- **Blue hydrogen** is produced from fossil fuels, like grey hydrogen, however CO2 emissions during production are sequestered or reused via carbon capture, utilisation and storage (CCUS). As a result, blue hydrogen is low carbon and is also becoming increasingly cost competitive as CCUS technologies evolve.
- **Green hydrogen** ("e-Hydrogen") is produced from renewable electricity through electrolysis, using devices known as electrolysers. With the only products of this reaction being heat and water, this process has zero carbon emissions. Green hydrogen currently accounts for less than 1% of hydrogen production, and currently is significantly (approximately four times) more expensive than using conventional technologies.

How much hydrogen?

Partial blending

There is some broad consensus that blending low concentrations, such as up to 20% hydrogen by volume, is currently viable, although the suitable composition of hydrogen in gas networks continues to be investigated. Some notable projects and studies that provide evidence for the technical feasibility include:

- According to one study, 5-15% hydrogen, on a volumetric basis, can be blended with natural gas without requiring significant modifications to the existing natural gas pipeline systems. [49]
- The GRHYD project conducted by ENGIE has reached 20% hydrogen, by volume, in local residential natural gas distribution networks in France in 2019. [50]
- The HyDeploy Project in the UK, led by gas distribution network Cadent, is currently blending 20% hydrogen at Keele University in Staffordshire. Preliminary results show that gas network and appliances are operating normally and have not required any changes. [51]

A weakness of blending hydrogen at these low concentrations is that the environmental benefit, compared with conventional natural gas, is relatively insignificant. This is particularly true as hydrogen has a lower volumetric energy density than natural gas, meaning that blending a certain volume percentage of hydrogen will result in a lesser percentage of overall energy coming from hydrogen in the blend. For a frame of reference, a blend of 20% hydrogen by volume roughly equates to 7.3% hydrogen when measured by overall energy content. [52]

A pure hydrogen network

As an extension, an important concept to watch is hydrogen's potential to fully replace natural gas in the grid – that is, reaching 100% volume – to create a pure hydrogen network. Several projects have already begun to assess the feasibility of this concept, most notably the H21 Leeds City Gate Project in the UK. [53] The findings of this project revealed that the existing gas network in Leeds has the correct capacity for a conversion to 100% hydrogen; it can be converted incrementally over a three-year period with minimal disruption to customers; minimal new energy infrastructure will be required compared to alternatives; and the existing heat demand for Leeds can be met using technology available today. Although these findings are promising, a number of technical uncertainties remain (e.g. method of storage, safety, and compatibility of end-use appliances).

The other key question is whether a pure hydrogen network would be economic. If it is assumed that the hydrogen is green hydrogen – then considering solely the cost of the energy component, it is clear that it would be several times more efficient to use electricity to run a heat pump, than it would be to convert that same amount of electricity to hydrogen and operate a boiler. To offset this increased energy cost the hydrogen network would either need to be a far cheaper form of delivery than the electric network, or it would need to address a problem more cheaply than the electric system (most likely energy storage). In our opinion, this may occur for certain applications (eg. transport, hard to electrify industrial) or in cold climates, but we have less confidence at this stage in 100% hydrogen providing a broad-based solution that is economical.

The technical challenges of hydrogen

Safety in gas networks

Aside from the economics, safety and feasibility concerns of blending hydrogen into natural gas networks have restricted the progression of such a solution. It is also worth noting the use of hydrogen varies between gas distribution and transmission networks due to their varied composition. One concern is that exposure to hydrogen can degrade the durability of some metal pipes over time, particularly in high concentrations and at high pressures. An analysis of the US natural gas distribution system in 2013 revealed that most metallic pipes are primarily composed of low-strength steel, which are generally not susceptible to hydrogen-induced embrittlement under normal operating conditions, thus making this a minor concern in the context of blending lower concentrations of hydrogen in the US. [54] The review also concluded there are no integrity concerns for other pipe materials, including ductile iron, cast and wrought iron, copper, polyethylene (PE) or polyvinylchloride (PVC). To accommodate higher concentrations of hydrogen, necessary system modifications may include the possible replacement of piping with high-performance polymers or engineered steel. On this front, it is worth noting that gas LDCs have already been replacing old pipes with polymers and this is expected to continue, which will in turn assist with accommodating hydrogen in the systems.

Another risk concerning gas transmission and distribution infrastructure is the potential for increased probability of ignition and resulting damage, as hydrogen has a broader range of conditions under which it will ignite. For the US natural gas system, the same analysis revealed that adding volumes of up to 20% hydrogen results in a minor increase in the risk of ignition and minor increases in the severity of the explosion in the event of an explosion from a gas leak. However, these risks increase at higher concentrations of hydrogen, and are more so for distribution systems given the greater population density in which they are located. This would likely translate to higher maintenance costs in order to conduct more frequent inspections and install additional leak detection systems. Furthermore, at high concentrations (greater than 50%), hydrogen blends can impede the accuracy of existing gas meters.

Compatibility with end-use appliances

Compatibility with end-use gas appliances is another important limiting factor, as the high flammability of hydrogen means it burns at temperatures higher than currently suitable for use in most combustion turbines and appliances used today.[55] Additionally, hydrogen has a different flame speed, combustion air requirement index (CARI), and Wobbe Index to methane.[xi] These differences mean many currently-installed household appliances, including boilers or stoves, are incompatible for combustion of hydrogen at higher concentrations.[56] Although impacted by the type and age of appliance, evidence to date suggests that blends greater than 20% by volume are likely to increase risks and require modifications to, or replacement of, most appliances. These challenges are likely to result in costly upgrades and disruptions to supply, which will ultimately impact the affordability of and sentiment towards such a solution, along with the higher cost of hydrogen compared to natural gas. For instance, an analysis by McKinsey & Co. found that blending hydrogen at $2 per kilogram at a 5%, 10% and 20% volumes results in a 5%, 10% and 22% increase in the end price of gas.[57]

Nonetheless, these solutions represent an opportunity for gas utilities, potentially allowing future use of – rather than stranding of – trillions of dollars of assets that are already deployed, notwithstanding necessary adjustments to equipment standards and infrastructure upgrades.

Considering together these risks and opportunities for the gas LDC systems, we expect that for the coming decade there will continue to be strong investment opportunities – and so rate base growth – driven significantly by safety and environmental policies and objectives. We then expect that that for an extended time, beyond this initial time period, that the gas system will continue to be widely used for industrial, commercial and residential purposes. For these reasons the gas LDC systems remain an important and valuable piece of energy infrastructure today.

In the very long-term we do see uncertainty in relation to how the gas systems will be utilised, and so their longer-term value to society. This uncertainty is factored into our valuation models, causing a general negative impact to our terminal values. From this perspective, we believe that some gas LDC businesses are better positioned than others – with better protections afforded to gas systems within colder climates, and gas systems that are owned as part of a multi-utility.

Producing hydrogen

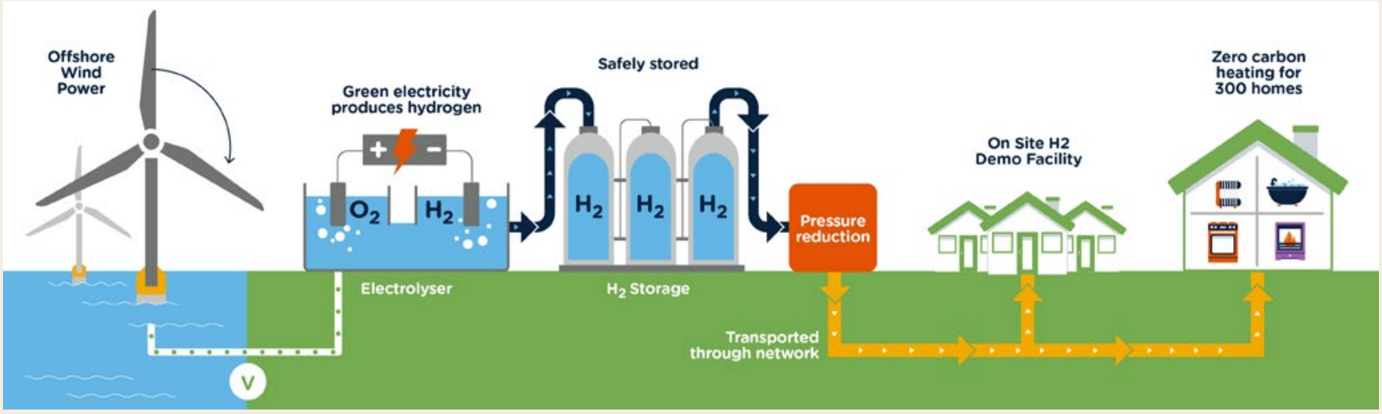
In the US, around 10 Mt of hydrogen is produced per year, accounting for approximately 15% of global supply, with almost all used in oil refining, ammonia production, and methanol production.[58] As the majority of this is grey hydrogen, production is highly carbon intensive. Global production of low carbon (blue and green) hydrogen remains low at around 0.36 Mt per year, which substantially lags the estimated amounts needed to achieve international climate goals (i.e. the Paris Agreement), at nearly 8 Mt by 2030.[59] McKinsey & Co. estimates hydrogen demand in the US could grow to 17 Mt by 2030 and 63 Mt by 2050 (or around 14% of energy demand).[60]

The largest challenge for hydrogen is its production costs, which are likely to remain uneconomical compared with fossil fuels in coming years, with fuel costs representing the largest cost component (45% to 75%). Low gas prices in the US and compatibility with existing natural gas infrastructure enables blue hydrogen (i.e. when using CCUS coupled with conventional technologies) to have the lowest capital and production costs, meaning it remains the preferred solution to expand low carbon hydrogen production.[xii]

Additionally, hydrogen produced via natural gas (i.e. grey and blue) has the highest production efficiency, requiring the least amount of resources to produce one kilogram of hydrogen.[61]

This presents an opportunity for natural gas, to play a bridging role in providing both infrastructure for hydrogen transportation and lower cost fuels for hydrogen production. However, blue hydrogen is a more emissions-intensive solution compared to green hydrogen, and is therefore less appealing from a “net zero” emissions and international climate goal perspective.

Globally, there are around 50 targets, mandates and policy incentives in place today that directly support hydrogen, with the majority focused on transport. In the US, there is no formalised national hydrogen policy, although the Department of Energy (DOE) plans to invest up to $100m over five years under a Hydrogen Strategy to accelerate R&D and deployment. NextEra plans to build its first green hydrogen power plant in Florida, while Entergy has proposed a power plant in Texas with the option to use 30% hydrogen. We expect this support, along with improved technology and cost competitiveness of CCUS, electrolysers and renewable electricity, will be a key accelerant for the use of low carbon hydrogen.



Source: Scotia Gas Networks Limited (SGN) Website. Gas Goes Green. Retrieved from https://www.sgn.co.uk/about-us/future-of-gas/gas-goes-green.
For further information, also see SGN's H100 Fife project video: https://www.sgn.co.uk/H100Fife

xi. CARI is a measurement of the combustion air required for a gas. Wobbe Index is a measure of the ability of a gas to deliver heat through a jet hole at constant conditions.
xii. Estimates of the LCOE of hydrogen range from $1.00-1.89/kg for grey hydrogen. $1.43-$2.15/kg for blue hydrogen, and $4.50-$6.00/kg for green hydrogen.

Conclusion

The energy sector plays a pivotal role in the modern world, helping drive significant quality of life improvements, as well as immense technological innovations.

We believe US electric utilities stand to benefit strongly from the trends discussed in this paper, as they will need to make not only significant investments in renewables generation, but also T&D infrastructure to help connect new sources of load and deal with a more complex grid. This represents an enormous, multi-decade investment opportunity for the sector. In relation to new T&D infrastructure, these investments will be made entirely by the regulated utilities, increasing regulated asset base, and therefore regulated returns, for investors.

The main limiting factor to what we otherwise see as an attractive, long-dated, visible growth opportunity, is whether or not electricity can be provided to customers at an affordable rate. Due to ongoing electrification trends, as well as lower fuel and O&M costs from new renewables generation, we believe it is likely the electric utilities will be able to continue growing their asset base strongly over the next few decades, while ensuring customer affordability. Additionally, we are attracted to the regulated nature of these assets that provides more clarity over the returns profile versus other unregulated renewables developers.

The role of gas networks is a lot more uncertain. Despite natural gas having played a substantial role in reducing CO2 emissions to date, if the global climate objective is to ultimately to achieve net zero emissions, then it is unlikely gas will play as large a role in a longer-term solution as has been previously assumed. Whilst we recognise the real risk of existing gas networks becoming “stranded assets”, we also believe that:

1) There are certain applications in which the gas network is more likely to play a longer-term role, for example, in harder to electrify sectors, such as heavy industry and transportation, and in helping to manage peak energy demand in colder climates.
2) Technological advancements are opening up opportunities for existing gas networks to decarbonise and potentially be re-purposed, for example, to transport and deliver RNG and/or pure or blended hydrogen.

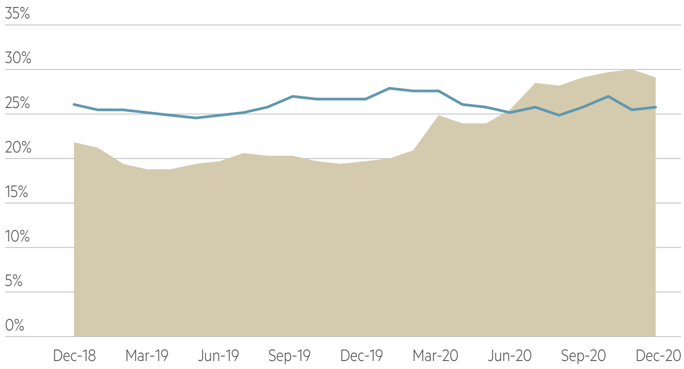
As global energy needs continue to evolve, we believe it is critical for infrastructure investors to continue monitoring these trends, as they will have a significant impact on the growth outlook for these businesses. Overall, we believe the outlook for electric utilities has strengthened over time as it is now supported by strong, structural decarbonisation and electrification tailwinds that provide a robust multi-decade growth opportunity. Conversely, the outlook for gas utilities has generally declined, and while certain applications for the gas network are harder to disrupt, and technologies (such as hydrogen) are being explored to extend the lives of these assets, we believe the outlook is much less visible.

Putting research into practice, the Maple-Brown Abbott Global Listed Infrastructure team has meaningfully shifted its portfolio over the last two years:

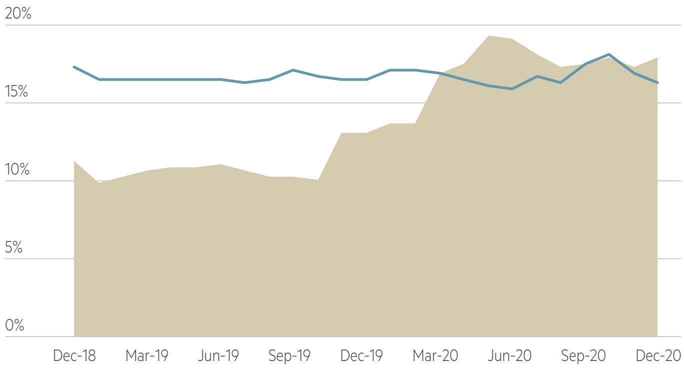
- Increasing our exposure to electric utilities from 22% to 29% (versus the FTSE at 26%);
- Increasing our exposure to multi-utilities from 11% to 18% (versus the FTSE at 16%); and
- Decreasing our exposure to gas utilities from 4% to 1% (versus the FTSE at 5%).

Figure 8: MBA GLI portfolio positioning over time

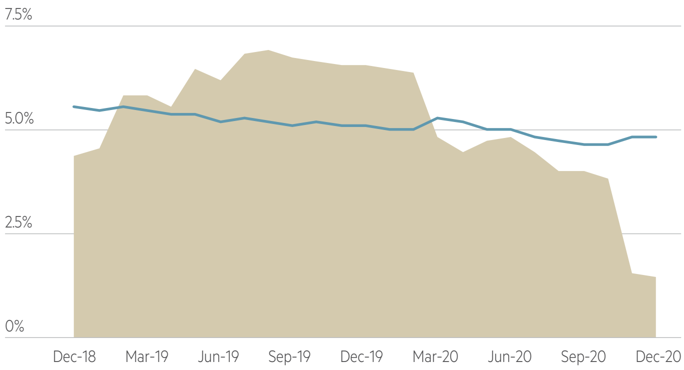
Global electric utilities exposure



Global multi-utilities exposure



Global gas utilities exposure



GLI Portfolio — FTSE Global Core Infrastructure 50/50 Index (Net Tax) AUD

Source: Maple-Brown Abbott, Bloomberg as at 31 December 2020.

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