Energy

2024

12th Edition

Contributing Editors: **Michael Burns & Antony Skinner**

Global Legal Group

Global Legal Insights
Energy

2024, 12th Edition
Contributing Editors: Michael Burns & Antony Skinner
Published by Global Legal Group

GLOBAL LEGAL INSIGHTS – ENERGY

2024, 12th EDITION

Contributing Editors
Michael Burns & Antony Skinner, Ashurst LLP

Publisher
Ben Lawless

Production Editor
Megan Hylton

Head of Production
Suzie Levy

Chief Media Officer
Fraser Allan

CEO
Jason Byles

We are extremely grateful for all contributions to this edition.
Special thanks are reserved for Michael Burns & Antony Skinner of Ashurst LLP for all of their assistance.

Published by Global Legal Group Ltd.
59 Tanner Street, London SE1 3PL, United Kingdom
Tel: +44 207 367 0720 / URL: www.glgroup.co.uk

ISBN 978-1-83918-315-7
ISSN 2050-2109

Printed and bound by TJ Books Limited
Trecerus Industrial Estate, Padstow, Cornwall, PL28 8RW
December 2023

CONTENTS

PREFACE

We are pleased to present the 12th edition of *Global Legal Insights – Energy*. The book contains 14 jurisdiction chapters, providing a truly international and far-reaching snapshot of energy policy, industry and regulation across the globe. The book is designed to provide general counsel, financial institutions, government agencies and private practice lawyers with a comprehensive insight into the most important trends and developments in the energy market across a range of key jurisdictions. The energy industry is never static, with both the industry and policy- and lawmakers constantly responding to new challenges and opportunities.

The last few years have been dominated by global events that have had a significant impact on the energy industry and energy policy across the globe: the COVID-19 pandemic and the Russia-Ukraine war in particular. Most recently this has been followed by new conflict in the Middle East, which, if it escalates, could add fresh instability to energy security and energy prices. At the same time, there is increasing impetus on governments and industry to increase efforts in implementing the energy transition. The challenge of addressing climate change is an issue that will, and indeed must, continue to drive change in the energy space, particularly in light of recent confirmation that 2023 was the hottest year on record. The degree to which these factors shape the energy industry and policy in different countries varies according to their political and economic status, and the nature of their indigenous energy supplies, but there is a degree of commonality in the pursuit of cheaper and cleaner energy to meet the needs of industry and local communities.

In producing *Global Legal Insights – Energy*, we have gathered together the views and opinions of a group of leading energy practitioners from around the world in a unique volume. The authors were asked to provide personal views on practical issues, policy issues, strategic issues, and legal and regulatory issues in their own jurisdiction, with free rein to decide the focus of their own chapter.

One of the attractions of comparative analysis is that developments in one jurisdiction can inform understanding and practice in another.

Our thanks to all the authors for their contributions, and particular thanks to our colleague Justyna Bremen for her invaluable help. We hope that this book will prove interesting and stimulating reading for you.

Michael Burns & Antony Skinner
Ashurst LLP

Australia

Darren Murphy, Dan Howard & Sophie Dilda

Overview of current energy mix

Historically, fossil fuels (coal, oil and gas) have consistently been Australia's dominant energy source. In 2021–22, fossil fuels (coal, oil and gas) accounted for approximately 91.1% of Australia's primary energy mix (27.5% coal, 36.5% oil and 27.1% gas). Renewables made up the remaining 8.9%.[1]

Australia's energy mix varies across the Australian States and Territories. There are substantial differences in the quantities as well as the forms of energy that are generated and consumed in each, owing to significant variation in geography, population density, lifestyle factors, climate and local economic drivers.

On 29 September 2023, the Department of Climate Change, Energy, the Environment and Water published its 2023 Australian Energy Update,[2] which indicates that the energy consumption across all sectors of each State and Territory (excluding the Australian Capital Territory, which has small consumption) is as follows:

Resource	**State or Territory**						
	New South Wales	Victoria	Queensland	Western Australia	South Australia	Tasmania	Northern Territory
Coal	39.5%	**35.3%**	33.7%	9.6%	8.8%	8.5%	0.0%
Oil	**40.5%**	35.2%	**35.1%**	33.6%	**47.8%**	38.4%	25.1%
Gas	10.7%	20.4%	21.2%	**53.5%**	27.1%	6.8%	**73.8%**
Renewables	9.3%	9.0%	9.9%	3.3%	16.3%	**46.3%**	1.1%

Tasmania (46%) and South Australia (16%) are leading the charge in Australia's move towards renewable energy sources, due respectively to hydro resources in Tasmania and wind and solar power in South Australia. In light of the Federal Government's recent commitment to reduce emissions targets to 43% below 2005 levels by 2030 and 82% renewable electricity by 2030 in the national energy mix, the rest of Australia can be expected to follow suit.[3] To meet these targets, significant additional uptake in major renewable energy projects is expected, including through additional offshore wind, hydrogen, energy storage and carbon capture.

It is important to note that the above percentages represent consumption across all sectors and do not necessarily reflect the electricity generation mix where, for example, Tasmania produces over 90% of its electricity from renewable hydroelectricity.

Continued overleaf

Changes in the energy situation in the last 12 months that are likely impact future direction or policy

Cost of electricity

Arguably the greatest change in Australia's energy situation in 2022–23 has been the spike in the cost of electricity.

On 25 October 2022, the Federal Government released its October 2022–23 Budget, in which it identified that the Treasury assumed that retail electricity prices would increase by an average of 20% nationally in late 2022, and by a further 30% in 2023–24.[4] The Australian Competition and Consumer Commission (**ACCC**) confirmed that electricity bills have risen by $300 on average since April 2022. This is the equivalent of a 25% increase for the median residential household in the National Electricity Market (**NEM**).[5]

The cause of this price increase is complex and multifaceted, with global factors and local economic, political and weather-related events, amongst other factors, playing a contributing role.

Global factors

Australia, like the rest of the world, has felt the impact of an unstable energy market owing in part to global factors such as the Russia/Ukraine war and post-COVID-19 supply chain issues.

The war in Ukraine, coupled with other supply chain issues and shortages, led to a significant increase in the price of Australian fossil fuels in the first half of 2023, although this has abated somewhat in the last quarter of 2023. The electricity and gas markets are expected to remain volatile in 2024 due to difficulties with the energy transition away from large coal-fired generation.

Australia-centric factors

- *Weather events*

Extreme weather events such as bushfires, heat waves and flooding have been frequent and severe as a result of La Niña.[6]

An El Niño weather cycle is now starting in Australia, with hotter and drier conditions predicted until at least the end of the southern hemisphere summer 2023–24.[7] An El Niño event can intensify heat waves, increase the severity of bushfires and contribute to drought conditions.

Extreme heat is regarded as one of the most significant stresses on Australia's energy systems due to its simultaneous effect on both energy demand and supply.[8] It is anticipated that power demand will reach the upper end of the forecast range in most regions, with the risk of bushfires also disrupting power infrastructure.[9]

- *Transition to clean energy*

Australia has been grappling with ensuring that its existing energy system continues to operate reliably while new renewables infrastructure is constructed.

The transition to greater reliance on renewable energy sources presents a difficult challenge, and will involve significant investment in a truncated time period if Australia is to meet its emissions targets. The process will be expensive and complicated, and the implementation of policies at a Federal level will be required to support investment in circumstances where coal power plants are being retired and worsening upward pressures on pricing.[10]

Australia is at a point of "maximum risk" in respect of the transition, in that Australia's energy infrastructure must be retired and replaced without this transition causing an energy shortage or further extreme increases in energy costs.[11] The Australian Energy Market

Operator (**AEMO**) recently reported that almost two-thirds of Australia's coal-fired generation capacity is expected to close before 2033.[12] These closures are set to coincide with delays in building new clean energy projects to replace capacity. AEMO warns that east coast Australians are at risk of electricity shortages in the period through to 2027 without a significant boost in production.[13]

Industry participants are calling for the project approvals process to be streamlined and for the construction of new supply to be standardised such that capital can be deployed at a pace and scale that will enable Australia to meet its energy needs in this period of transition.[14]

In addition to concern regarding electricity shortfalls, the installation of replacement clean generation is running well behind what is needed to meet Australia's reduction commitments. This is primarily due to delays in installing new transmission infrastructure and slower-than-anticipated approvals for large scale renewable projects. The International Energy Agency (**IEA**) warns that Australia's net zero commitment requires a faster trajectory and increased efforts in energy efficiency and renewable energy. It also calls for a clear policy road map with key milestones by sector and policy area to bridge reliability gaps.

- *Growth in energy exports*

While Australia extracts coal and gas in quantities that would be sufficient to sustain its own energy needs, Australia is a "*substantial net exporter of energy, including coal and natural gas, with net exports equating to over two-thirds of production*".[15] In 2021–22, Australia exported approximately 91% of black energy coal production, 76% of domestic natural gas production and 86% of crude oil production.[16]

Australia is a leader in liquefied natural gas (**LNG**) trade, with Australian LNG making up approximately 20% of global LNG exports.[17] LNG exports experienced a 7% growth in 2021–22, partially attributable to the rebound from outage and maintenance impacts from the previous year, and also driven by higher post-lockdown gas demand in Asian markets.[18] Exports of LNG have grown by an average of 16% per year over the past decade.[19]

Volatility in domestic gas prices and unplanned shutdowns of major coal-fired generators have resulted in domestic wholesale energy price volatility.

On 11 July 2023, the Federal Government introduced a Mandatory Code of Conduct for the east coast gas market in an attempt to support sufficient energy supply and manage domestic prices for energy (discussed further below).[20]

<u>Electricity industry price volatility</u>

On 14 September 2023, the Australian Energy Market Commission proposed new changes to the National Electricity Rules targeting electricity system reliability for households and businesses during the transition towards net zero.[21]

The changes propose to:[22]

(a) progressively increase the Market Price Cap (**MPC**) from $18,600/MWh on 1 July 2025 to $22,800/MWh on 1 July 2027;

(b) progressively increase the Cumulative Price Threshold (**CPT**) from $1,674,000/MWh on 1 July 2025 to $2,325,600/MWh on 1 July 2027 (the threshold for seven-day aggregate of each five-minute trading interval market price); and

(c) maintain an Administrated Price Cap at its current level of $600/MWh from 1 July 2025 to 30 June 2028.

The draft rule aims to progressively realign the MPC and CPT to the level needed for new entrant investment. This will support investments in a mix of entrant technologies that are required during the transition to higher penetrations of renewable energy.[23]

Developments in government policy/strategy/approach

Australia's policy landscape is constantly evolving, with significant movement in the last year owing to numerous factors, including a new Federal Government and recently introduced, more ambitious reduction emission targets.

This section of the chapter outlines some of the key developments in government policy and the approach at a Federal (and, briefly, State/Territory) level.

Federal developments

Powering Australia Plan

In 2022, the Federal Government announced its Powering Australia Plan (**Plan**), an umbrella policy that "*centres on reducing emissions while creating jobs*", "*lowering power bills in the long term*" and "*prioritis[ing] growth and investment in the regions*".[24] The Plan is stated to generate an estimated $76 billion in investment and create 604,000 jobs by 2030 (primarily in the regions).[25]

Some of the key developments that have occurred in line with the Plan's aims over 2023 include:

(a) *National Energy Transformation Partnership (**NETP**)*: The Federal Government is taking a collaborative approach with States and Territories under the new NETP.[26] The NETP's priorities include planning for adequate energy generation and storage, understanding demand evolution, coordinating gas and electricity planning, enhancing energy security management, accelerating nationally significant transmission projects and strengthening energy governance architecture.[27]

(b) *Energy Price Relief Plan*: The Federal Government introduced the Energy Price Relief Plan in December 2022 to address the immediate impact of price increases on Australian households and small businesses.[28] This plan, alongside the imposition of price caps on coal and gas, is expected to reduce electricity price growth by 25% and lower retail gas price growth by approximately 16% in 2023–24.[29]

(c) *National Electric Vehicle Strategy*: Australia's first National Electric Vehicle Strategy was released on 19 April 2023. The strategy aims to increase the uptake of electric vehicles across Australia, reduce emissions and improve the health and wellbeing of Australians. The strategy includes the development of the first Fuel Efficiency Standard for light vehicles.

National Hydrogen Strategy

A key focus of the Federal Government is the implementation of a National Hydrogen Strategy, which "*sets a vision for a clean, innovative, safe and competitive hydrogen industry*" and aims to position Australia as a major global player in the hydrogen industry by 2030.[30]

The strategy explores Australia's clean hydrogen potential, considering future scenarios with wide-ranging growth possibilities.[31] The plan includes the creation of "hydrogen hubs" (clusters of large-scale demand) at ports, in cities, or in regional or remote areas to provide a "*springboard to scale*".[32] The creation of hubs is intended to render infrastructure development more cost-effective while promoting efficiencies from economies of scale, fostering innovation and promoting synergies from sector coupling.[33]

Offshore Renewable Growth Strategy

The Federal Government announced plans to fast-track the development of an offshore wind industry, with the commencement of the *Offshore Electricity Infrastructure Act 2021* (Cth) in June 2022. This framework enables the construction, operation and decommissioning of offshore wind farms in the Commonwealth offshore area.[34] The accompanying regulations outline detailed arrangements, such as the offshore electricity infrastructure licensing scheme, spatial data provisions, arrangements for pre-existing infrastructure and the application of fees and levies.[35]

In the last 12 months, a number of areas have been declared suitable for offshore wind, including Gippsland, Victoria (**Gippsland Declared Area**) and Hunter, New South Wales (**Hunter Declared Area**).[36] Two new potentially suitable areas have also recently been proposed in Commonwealth waters:

(a) a region in the Southern Ocean extending offshore from Warrnambool, Victoria to Port MacDonnell, South Australia (**Southern Ocean Offshore Wind Development Region**) – consultation on this proposal closed on 31 August 2023; and

(b) a region in the Pacific Ocean off Illawarra, New South Wales, extending offshore from Wombarra to Kiama (**Pacific Ocean Offshore Wind Development Region**) – consultation on this proposal closed on 16 October 2023.

A further two regions, being the Bass Strait region off Northern Tasmania and the Indian Ocean region off Perth/Bunbury, Western Australia, have been identified as priority areas for assessment for area declaration. Further details regarding these two regions and the public consultation processes will be announced in late 2023.

However, industry participants are encountering obstacles in obtaining timely project approvals and certainty as to location and connection to the transmission system.

Nuclear power on the Federal political agenda

The debate surrounding whether nuclear power should be part of Australia's future energy mix is again on the Federal political agenda. The Federal Coalition opposition party has proposed that nuclear power, and specifically small modular reactors (**SMRs**), potentially hold the answer to Australia's energy transition and that SMRs are needed to achieve net zero by 2050.

The Federal Government has dismissed the Coalition's proposal, contending that nuclear power is the most expensive source of energy in the world and distracts from the urgent need to transition Australia's energy sector to renewables.[37]

Australia's historical abundance of uranium and the need for large dispatchable generation to support energy security and reliability has placed nuclear power back on the political agenda, though it faces stiff opposition from a range of political and environmental groups.

Delivering priority transmission projects

The Federal Government has identified as part of its energy policy that the electricity transmission network is the backbone of the NEM and that it is critical to ensure that the NEM's transmission network is "*fit for purpose and ready for the renewables and storage investment needed for the decarbonisation task ahead*".[38]

On 30 July 2022, AEMO published its 2022 Integrated System Plan (**ISP**), which provides a 20-year plus forecast of the NEM's infrastructure needs.[39] The ISP identified that Australia requires more than 10,000 km of new transmission lines and nine times the large-scale renewable generation in order to succeed in its renewable energy transition, and recommended key transmission projects to ensure the reliability and security of the NEM.

The ultimate goal of these key upgrades of the electricity transmission network is to "*improve electricity affordability by enabling renewable generation and large scale storage investment across the NEM and allowing this to be shared between regions, increasing wholesale electricity market competition*".[40]

Since September 2022, more than $12 billion has been allocated to primary transmission projects, including the Marinus Link between Tasmania and Victoria, Renewable Energy Zones (**REZs**) in Victoria and New South Wales, and the Victoria–NSW Interconnector.[41]

*The Foreign Investment Review Board (**FIRB**) – national security and data protection*

FIRB is a non-statutory body that was established in 1976 to advise the Treasurer and the Federal Government on Australia's Foreign Investment Policy and its administration.[42]

FIRB has emphasised that the "*access and control afforded by foreign investment in the energy sector may create opportunities for foreign actors to harm national security*" and that if sabotage or foreign interference activity significantly impacted the energy sector, it would "*lead to cascading consequences for a range of other sectors, significantly impacting Australia's economy, society and security*".[43]

As such, FIRB has increased its focus on national security and data protection, particularly in relation to foreign investment proposals that involve ownership or transfer of, or access to, personal information and other sensitive, industry-specific data.

Foreign investors in Australia's energy sector can therefore expect an increased level of scrutiny and more intensive interactions with FIRB.

State/Territory developments

In addition to developments at a Federal level, there have been developments in the specific policies implemented and approaches taken by the governments of the various States and Territories of Australia that are working towards renewable energy targets.

REZs are being implemented at the State and Territory level as part of the Energy Security Board's post-2025 market design program.[44] AEMO identified 41 shortlisted REZs including six offshore zones across eastern Australia.[45]

Tasmania

Tasmania is leading Australia's renewables charge and is aiming to achieve 200% renewable energy by 2040 (having maintained net zero emissions for the last eight consecutive years).[46]

This achievement is attributable to significant investment in the renewables sector. The 2023–24 Tasmanian Budget will invest $3.75 million over two years into the State's Renewable Energy Plan to progress initiatives such as the Marinus Link, onshore and offshore renewable energy developments, hydropower projects and the implementation of REZs.[47]

In May 2023, Hydro Tasmania announced a $700 million plan to redevelop the Tarraleah hydropower scheme, which will involve upgrading works and evaluating the feasibility of constructing a new scheme and power station.[48] This initiative aims to boost the output from 110MW to 190MW using the same volume of water. The project is currently under assessment for commercial viability, with a final investment decision expected in mid-2024.

Victoria

Victoria released new emissions reduction targets on 20 October 2022 with a commitment to reduce emissions by 75–80% (on 2005 levels) by 2035, as well as 95% renewable energy by 2035, and net zero by 2045.[49]

Victoria has also implemented an Offshore Wind Policy, which includes procuring projects that will generate at least 2GW of offshore wind online by 2032 (enough to power 1.5 million homes).[50] The first power from offshore wind is expected by 2028, and targets of 4GW and 9GW have been set for 2035 and 2040, respectively.[51]

The Victorian Government also announced on 20 October 2022 that it will revive the State Electricity Commission (**SEC**) to support Victoria's clean energy transition.[52] The SEC was first established in 1918 and, prior to the privatisation of the electricity sector in the 1990s, had become Victoria's sole provider of electricity generation, transmission and networks.[53] The Victorian Government's 2023–24 Budget commits $1 billion to revive the Commission, alongside other major funding for renewable energy projects and workforce training. The initial $1 billion investment will help deliver 4.5GW of renewable energy capacity, to be owned by the State and run by the SEC.[54]

Queensland

Under Queensland's Energy and Jobs Plan, the State has committed to 30% emissions reduction below 2005 levels by 2030 as well as 50% renewable energy by 2030, 70% renewable energy by 2032 and 80% renewable energy by 2035.[55]

The Queensland Government's 2023–24 Budget includes a landmark capital investment of $19 billion over the forward estimates to deliver on the Queensland Energy and Jobs Plan.[56] Government-owned energy enterprises are leading Queensland's energy transformation, investing in new wind, solar, storage and transmission, supported by the $4.5 billion Queensland Renewable Energy and Hydrogen Jobs Fund.[57]

The Queensland Government is continuing to invest in the Queensland hydrogen industry, which is anticipated to be worth approximately $1.7 billion a year in exports by 2030.

New South Wales

New South Wales released new emissions reduction targets on 22 December 2022 with a commitment to reduce emissions by 70% (on 2005 levels) by 2035.[58]

On 3 February 2023, the New South Wales Government launched the $5 million first stage of their Clean Manufacturing Precinct project, to provide clean infrastructure and technology to energy-intensive businesses in the Hunter and Illawarra regions.[59]

The New South Wales Government also recently committed $1.8 billion to support the State's renewable energy transition, including establishing the Energy Security Corporation and investing to connect new projects to the grid.[60] The Energy Security Corporation will focus on investing in storage projects, addressing market gaps, and improving the reliability of the State's electricity network.[61]

Developments in legislation or regulation

<u>Safeguard Mechanism reforms</u>

Australia has (as of 1 July 2023) reformed the existing Safeguard Mechanism to limit the Scope 1 greenhouse gas emissions of Australia's largest industrial facilities by imposing maximum emissions limits called "baselines". Each facility is subject to its own "baseline", calculated in accordance with a prescribed formula, which will decline by 4.9% each year until 2030.

Facilities that exceed their baseline must either purchase Safeguard Mechanism Credits (**SMCs**) or Australian Carbon Credit Units (**ACCUs**) to offset their emissions. Facilities with emissions below their baseline in a given financial year will automatically generate SMCs; a new form of tradeable carbon credits with 1 SMC representing 1 tonne of carbon dioxide equivalent saved.

Flexible compliance options are currently in place to ease the transition until 2030. During this transition period, facilities can seek borrowing adjustments, multi-year monitoring periods or discounted baselines. Facilities may also "bank" their SMCs for future use and purchase ACCUs from the Australian Federal Government at a fixed price.

The reformed Safeguard Mechanism also provides for a legislated cap on total Scope 1 emissions from all facilities covered by the mechanism, which will decrease over time. The Australian Federal Minister for Climate Change and Energy has the ability to consult upon and amend aspects of the Safeguard Mechanism if overall emissions are not declining at a satisfactory rate.

The Department of Climate Change, Energy, the Environment and Water has initiated consultations on guidelines to set international best practice emissions intensities for use by new facilities under the Safeguard Mechanism.[62] These guidelines, once finalised, will inform the development of international best practice emissions intensities, which will be used to calculate baselines for new facilities.

Gas Market Code

On 11 July 2023, the Federal Government's Mandatory Code of Conduct for the east coast gas market came into effect (**Gas Code**).[63] The implementation of the Gas Code highlights the Federal Government's ongoing willingness to intervene in Australia's domestic gas market, especially in anticipation of forecasted supply shortages to maintain quantities and cap prices. It replaces an emergency price order imposed in 2022, which capped gas prices as a temporary measure.

The Gas Market Code applies to wholesale gas producers and their affiliates in the east coast gas market. It imposes a gas price cap of $12 per gigajoule (**GJ**) and a Mandatory Code of Conduct to support sufficient energy supply and ensure that Australians are not paying excessive prices for energy.[64] The ACCC has the authority to review and update the price cap every two years, or earlier within that period if there are significant changes in market conditions or if authorised to do so by the Energy Minister and Resources Minister.[65] This means that the current cap of $12/GJ will continue until at least July 2025.[66]

The ACCC oversees compliance, with penalties of up to $50 million or 30% of a company's turnover for non-compliance.[67] Reporting obligations are outlined under the Gas Code, aiming to maintain market integrity. The Code's implementation aligns with the Energy Price Relief Plan, enhancing transparency and fairness in the east coast gas market.

Queensland coal royalty tax increase

The Queensland Government lifted coal royalty tax rates to the highest in the world in 2022 without consultation. The most striking component of these changes (given current high coal prices) is the royalty rate for prices above $300 per tonne, which has effectively been increased from 15% to 40%. Analysis by the Queensland Resources Commission demonstrates that Queensland's royalty rates are now nearly four times the global average.[68]

The measure announced last year faced significant opposition from the mining sector on the basis that it will have a long-term negative impact on mining exploration and development.[69]

The Queensland Government's budget papers revealed income of more than $15 billion from coal royalties in 2022–23, approximately $10 billion more than had been forecast 12 months ago due partly to sustained high coal prices.[70] The expected decline in commodity prices in 2023 and 2024 is anticipated to reduce royalties collected by the Queensland Government.

Petroleum Resource Rent Tax

Following the Treasury Gas Transfer Pricing (**GTP**) Review,[71] in May 2023 the Australian Government proposed changes to the Petroleum Resource Rent Tax (**PRRT**) aimed at bringing forward the point at which the LNG industry pays tax (and increasing the amount to be paid). Under the previous rules, most LNG projects were not expected to pay any significant amounts of PRRT until the 2030s.

The Government will proceed with eight of the GTP Review's 11 recommendations, including limiting the proportion of PRRT assessable income that LNG projects can offset by deductions to 90%, effectively capping the use of deductions.

A consultation process in respect of draft legislative amendments and explanatory materials relating to the deductions cap ran from 21 August 2023 to 15 September 2023. Consultation on other policy changes is expected to occur in early 2024.

Government funding/subsidies

*The Australian Renewable Energy Agency (**ARENA**)*

ARENA was established by the Australian Government in 2012 to "*support the global transition to net zero emissions by accelerating the pace of pre-commercial innovation, to the benefit of Australian consumers, businesses and workers*".[72]

Since 2012, ARENA has supported 663 projects with $2.25 billion in grant funding, unlocking a total investment of almost $9.75 billion in Australia's renewable energy industry.[73]

In 2023, ARENA funded a number of new projects, including:

(a) Hysata Capillary-fed Electrolyser Commercial-Scale Demonstration Project;
(b) Yarwun Hydrogen Calcination Pilot Demonstration Project;
(c) Hydrogen Park Murray Valley Facility; and
(d) Vast Solar Port Augusta Concentrated Solar Thermal Power Project.

*Clean Energy Finance Corporation (**CEFC**)*

The CEFC invests on behalf of the Australian Government in clean energy technologies, projects and businesses to accelerate Australia's transition to a low emissions economy. It leverages its investment commitments to "*attract additional investment from the private sector and share [its] market and investment experiences, insights and expertise across the broader market*".[74]

In 2022–23, the CEFC confirmed $1.9 billion in new investment commitments, including a record $1.2 billion in renewable energy and grid-related investment commitments.[75] Its investment highlights for 2022–23 include:[76]

(a) investment of $100 million in the New South Wales Waratah Super Battery, one of the largest standby network batteries in the world;
(b) investment of $222.5 million in Victoria's 756MW Golden Plains Wind Farm; and
(c) investment of $54.5 million in new and follow-on commitments via the Clean Energy Innovation Fund.

Judicial decisions, ministerial decisions, court judgments, results of public enquiries

Australian Energy Regulator (**AER**) prosecutions

The AER, Australia's national energy market regulator, is responsible for monitoring, investigating and enforcing compliance with obligations imposed under the National Energy Retail Law, National Electricity Law and National Gas Law, as well as their associated Rules and Regulations.

The AER prosecuted one case in the Federal Court in 2023: *AER v Pelican Point Power Ltd* [2023] FCA 1110. The Court's decision was handed down on 21 September 2023. Civil proceedings were also initiated against subsidiaries of AGL Energy Ltd on 30 June 2023 for alleged breaches of the National Electricity Rules and Jemena on 31 May 2023 for alleged breaches of the National Gas Rules.[77]

In *AER v Pelican Point Power Ltd*, the Federal Court found that Pelican Point Power Ltd breached the National Electricity Rules by failing to disclose to AEMO the full capacity of its power station that was available during heat wave conditions in February 2017.[78] The region's power system was not in a secure operating state for over 30 minutes due to the heat wave, causing AEMO to declare a "Lack of Reserve Level 3" event and direct an interruption of customer supply in order to restore power system security. Penalties have not yet been determined by the Court.

Rejection of the Kingston Offshore Wind Farm Project

The Kingston Offshore Wind Farm project, a $1.8 billion offshore wind farm to be located off the coast of Kingston (**Project**), was the first offshore wind project to be proposed in South Australian waters.[79] It is outside the Southern Ocean Offshore Wind Development Region. On 7 August 2023, the South Australian government rejected the application for the Project, likely due to environmental concerns related to the marine environment and to potential impacts on the local fishing industry.

This proposal rejection is an example of the timely approvals challenge facing Australia's clean energy transition. In addition to electricity shortfalls, the installation of replacement clean energy capacity is running well behind due to slower-than-anticipated approvals and a growing objection to large-scale renewable projects.

"Greenwashing" cases

"Greenwashing", defined by financial regulator Australian Securities and Investments Commission (**ASIC**) as "*the practice of misrepresenting the extent to which a financial product or investment strategy is environmentally friendly, sustainable or ethical*",[80] has been the subject of increased litigation in Australia in recent years.

On 9 August 2023, Australian Parents for Climate Action (**AP4CA**) filed a claim in the Federal Court of Australia against EnergyAustralia Pty Ltd (**EnergyAustralia**), alleging misleading marketing practices. EnergyAustralia is accused of greenwashing its "Go Neutral" products by falsely claiming them to be "carbon neutral" and environmentally beneficial.[81]

AP4CA contends that purchasing carbon credits to "offset" emissions does not truly cancel out the emissions generated from burning fossil fuels. The organisation is seeking a declaration that EnergyAustralia misled customers since 2019 about the greenhouse gas emissions associated with their electricity and gas usage, an order that EnergyAustralia be restrained from making "carbon neutral" or similar statements about the "Go Neutral" product, and that it issue a corrective statement to customers.[82]

This legal action marks the first Australian case against a company for marketing a consumer product as "carbon neutral".[83] The case is currently pending before the Court.

Requirement to consult native title parties – *Tipakalippa v NOPSEMA (No. 2)*[84]

In June 2022, Munupi Senior Lawman and Tiwi Traditional Owner, Mr Tipakalippa, commenced proceedings in the Federal Court against Santos NA Barossa Pty Ltd (**Santos**) and the government, challenging the National Offshore Petroleum Safety and Environmental Management Authority's (**NOPSEMA**) decision to approve plans to drill the Barossa gas field. This is the first case in Australia brought by First Nations people challenging an offshore project approval because of lack of consultation.

On 21 September 2022, Justice Bromberg found that NOPSEMA had invalidly accepted an environment plan submitted by Santos in relation to its proposed Barossa offshore gas project.

While Santos appealed Justice Bromberg's decision,[85] the Full Court unanimously dismissed the appeal in December 2022, determining that the traditional owners of the Tiwi Islands, the Munupi clan, were "relevant persons" whose "functions, interests or activities" might be affected by the project.[86] As the Munupi had not been consulted during the plan's preparation, NOPSEMA's acceptance of the plan was found to be invalid.

This decision emphasises the importance of petroleum titleholders consulting comprehensively with all relevant parties during environment plan preparations for offshore projects.

* * *

Endnotes

1. "Australian energy mix by state and territory 2021–21", *Australian Government – Department of Climate Change, Energy, the Environment and Water* (Web Page) https://www.energy.gov.au/data/australian-energy-mix-state-and-territory-2021-22
2. "Australian Energy Update 2023", *Australian Government – Department of Climate Change, Energy, the Environment and Water* (Web Page) https://www.energy.gov.au/publications/australian-energy-update-2023
3. "Annual Climate Change Statement 2022" (Report, Commonwealth of Australia, 1 December 2022) https://www.dcceew.gov.au/climate-change/strategies/annual-climate-change-statement
4. "Federal Budget October 2022–23 – Budget Strategy and Outlook" (Budget Paper No. 1, Commonwealth of Australia, 25 October 2022) https://budget.gov.au/content/bp1/index.htm
5. "Australia 2023 Energy Policy Review", *International Energy Agency* (Report, April 2023) https://www.iea.org/reports/australia-2023
6. "State of the Climate 2022", *CSIRO and Bureau of Meteorology* (Report, 2022) https://www.csiro.au/en/research/environmental-impacts/climate-change/state-of-the-climate
7. "ENSO Outlook: An Alert System for the El Niño–Southern Oscillation", *Bureau of Meteorology* (Web Page, 20 September 2023) https://www.csiro.au/en/news/all/news/2023/september/expert-commentary-el-nino
8. "Australia 2023 Energy Policy Review", *International Energy Agency* (Report, April 2023) https://www.iea.org/reports/australia-2023
9. "2023 Electricity Statement of Opportunities", *Australian Energy Market Operator* (Report, August 2023) https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo
10. Mark Ludlow, "Australia's White-Knuckle Ride to Net Zero", *Australian Financial Review* (Online, 14 October 2022) https://www.afr.com/companies/energy/australia-s-white-knuckle-ride-to-net-zero-20221013-p5bpho
11. "Energy Transition at Point of Maximum Risk", *Australian Financial Review* (Online, 11 October 2022) https://www.afr.com/policy/energy-and-climate/energy-transition-at-point-of-maximum-risk-20221010-p5boop
12. "2023 Electricity Statement of Opportunities", *Australian Energy Market Operator* (Report, August 2023) https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-reliability/nem-electricity-statement-of-opportunities-esoo
13. *Ibid.*

14. Angela Macdonald-Smith and Jenny Wiggins, "Electricity prices to soar as energy transition falters", *Australian Financial Review* (Online, 10 October 2022) https://www.afr.com/companies/energy/electricity-prices-tipped-to-rise-at-least-35pc-in-2023-20221010-p5boif
15. "Data – Energy Trade", *Australian Government – Department of Climate Change, Energy, the Environment and Water* (Web Page, 2022) https://www.energy.gov.au/data/energy-trade
16. *Ibid*.
17. "Global Resources Strategy Commodity Report: Liquefied Natural Gas", *Australian Government – Department of Industry, Science and Resources* (Report, 28 April 2022) https://www.industry.gov.au/sites/default/files/2022-09/grs-commodity-report-lng.pdf
18. "Australian Energy Update 2023", *Australian Government – Department of Climate Change, Energy, the Environment and Water* (Web Page) https://www.energy.gov.au/publications/australian-energy-update-2023
19. "Data – Energy Trade", *Australian Government – Department of Climate Change, Energy, the Environment and Water* (Web Page, 2022) https://www.energy.gov.au/data/energy-trade
20. *Competition and Consumer (Gas Market Code) Regulations 2023* (Cth).
21. "Amendment of the Market Price Cap, Cumulative Price Threshold and Administered Price Cap", *Australian Energy Market Commission* (Web Page, 14 September 2023) https://www.aemc.gov.au/rule-changes/amendment-market-price-cap-cumulative-price-threshold-and-administered-price-cap
22. "Draft Rule Determination: National Electricity Amendment (Amendment of the Market Price Cap, Cumulative Price Threshold and Administered Price Cap) Rule", *Australian Energy Market Commission* (Draft Determination, 14 September 2023) https://www.aemc.gov.au/sites/default/files/2023-09/Amendment%20of%20the%20MPC%2C%20CPT%2C%20APC%20-%20draft%20determination%20.pdf
23. *Ibid*.
24. "Government Priorities – Australia's Energy Strategies and Frameworks", *Australian Government – Department of Climate Change, Energy, the Environment and Water* (Web Page, 2022) https://www.energy.gov.au/government-priorities/australias-energy-strategies-and-frameworks
25. *Ibid*.
26. "National Energy Transformation Partnership", *Department of Climate Change, Energy, the Environment and Water* (Web Page, 12 August 2022) https://www.energy.gov.au/government-priorities/australias-energy-strategies-and-frameworks/national-energy-transformation-partnership
27. *Ibid.*
28. "Federal Budget 2023–24 – Budget Strategy and Outlook" (Budget Paper No. 1, Commonwealth of Australia, May 2023) https://budget.gov.au/content/bp1/index.htm
29. *Ibid.*
30. "Energy – Australia's National Hydrogen Strategy", *Australian Government – Department of Climate Change, Energy, the Environment and Water* (Web Page, 2022) https://www.dcceew.gov.au/energy/publications/australias-national-hydrogen-strategy
31. *Ibid*.
32. COAG Energy Council, "Australia's National Hydrogen Strategy", *Australian Government – Department of Climate Change, Energy, the Environment and Water* (Strategy, 22 November 2019), viii https://www.dcceew.gov.au/sites/default/files/documents/australias-national-hydrogen-strategy.pdf

33. *Ibid*.
34. "Australia 2023 Energy Policy Review", *International Energy Agency* (Report, April 2023) https://www.iea.org/reports/australia-2023
35. *Offshore Electricity Infrastructure Regulations 2022* (Cth).
36. "Establishing Offshore Wind", *Department of Climate Change, Energy, the Environment and Water* (Web Page, 20 September 2023) https://www.dcceew.gov.au/energy/renewable/establishing-offshore-infrastructure
37. "Five serious answers why nuclear is the wrong solution for Australia", *Chris Bowen – Minister for Climate Change and Energy (AFR)* (Web Page, 29 August 2023) https://www.afr.com/policy/energy-and-climate/five-serious-answers-why-nuclear-is-the-wrong-solution-for-australia-20230827-p5dzqa
38. "Government Priorities – Energy Supply – Delivering Priority Transmission Projects", *Australian Government – Department of Climate Change, Energy, the Environment and Water* (Web Page, 2022) https://www.energy.gov.au/government-priorities/energy-supply/delivering-priority-transmission-projects
39. *Ibid*.
40. *Ibid*.
41. "Powering Australia", *Department of Climate Change, Energy, the Environment and Water* (Web Page, 2023) https://www.energy.gov.au/government-priorities/australias-energy-strategies-and-frameworks/powering-australia
42. "About FIRB", *Australian Government – Foreign Investment Review Board* (Web Page, 2022) https://firb.gov.au/about-firb
43. Foreign Investment Review Board, *National Security* (Guidance Note No. 8, 12 April 2022) 24 https://firb.gov.au/sites/firb.gov.au/files/guidance-notes/GN08_NationalSecurity_1.pdf
44. "All about the Post 2025 project", *Energy Security Board* (Web Page, 2023) https://esb-post2025-market-design.aemc.gov.au/all-about-2025
45. "Appendix 3. Renewable Energy Zones", *Australian Energy Market Operator* (Appendix to 2022 ISP for the National Electricity Market, Report, June 2022) https://aemo.com.au/-/media/files/major-publications/isp/2022/appendix-3-renewable-energy-zones.pdf?la=en
46. Roger Jaensch, Minister for Environment and Climate Change, "Tasmanian Greenhouse Gas Emissions Report 2022 Released" (Media Release, Tasmanian Government – Premier of Tasmania, 3 August 2022) https://www.premier.tas.gov.au/site_resources_2015/additional_releases/tasmanian-greenhouse-gas-emissions-report-2022-released
47. Guy Barnett MP, Minister for Energy and Renewables, "Investing in our renewables energy future to benefit all Tasmanians", *Tasmanian Government* (Web Page, 2023) https://www.premier.tas.gov.au/budget-2023/budget-releases/investing-in-our-renewables-energy-future-to-benefit-all-tasmanians
48. Guy Barnett, Minister for Energy and Resources "Tarraleah Village returns to its renewable energy roots", *Hydro Tasmania* (Web Page, 2023) https://www.premier.tas.gov.au/site_resources_2015/additional_releases/tarraleah-village-returns-to-its-renewable-energy-roots
49. "Victoria Makes Gains in Race to Net Zero with New Targets" (Media Release, Climate Council, 20 October 2022) https://www.climatecouncil.org.au/resources/victoria-makes-gains-in-race-to-net-zero-with-new-targets
50. "Victoria Launches Australia's First Offshore Wind Targets" (Media Release, Premier of Victoria, 4 March 2022) https://www.premier.vic.gov.au/victoria-launches-australias-first-offshore-wind-targets

51. *Ibid*.
52. Dan Andrews, "Putting Power Back in the Hands of Victorians" (Media Release, Dan Andrews, 20 October 2022) https://www.danandrews.com.au/news/putting-power-back-in-the-hands-of-victorians
53. Peter Hannam and Benita Kolovos, "Daniel Andrews Plans to Revive the State Electricity Commission. What will it Mean for Victoria's Power?", *The Guardian* (Australia Edition) (Online, 22 October 2022) https://www.theguardian.com/australia-news/2022/oct/22/daniel-andrews-plans-to-revive-the-state-electricity-commission-what-will-it-mean-for-victorias-power
54. "State Electricity Commission", *Victorian Government* (Web Page, 25 August 2023) https://www.vic.gov.au/state-electricity-commission-victoria
55. "Queenslanders are Taking Strong Action on Climate Change", *Queensland Government – Queensland Climate Action* (Web Page, 2022) https://www.des.qld.gov.au/climateaction; "About the Plan", *Queensland Government – Department of Energy and Public Works* (Web Page, 2022) https://www.epw.qld.gov.au/energyandjobsplan/about
56. "Budget Strategy and Outlook 2023–4", *Queensland Government* (Budget Paper No. 2, 2023) https://budget.qld.gov.au/budget-papers
57. *Ibid*.
58. Michael McGowan, "Matt Kean announces NSW target to cut carbon emissions by 70% by 2036", *The Guardian* (Australia Edition) (Web Page, 23 December 2022) https://www.theguardian.com/australia-news/2022/dec/23/matt-kean-announces-nsw-target-to-cut-carbon-emissions-by-70-by-2035
59. "Clean manufacturing precinct project launches in the Hunter and Illawarra", *NSW Climate and Energy Action* (Media Release, 3 February 2023) https://www.energy.nsw.gov.au/news/clean-manufacturing-precinct-project-launches-hunter-and-illawarra
60. "Further $1.8 billion to power NSW to a clean energy future", *NSW Government* (Media Release, 7 September 2023) https://www.nsw.gov.au/media-releases/billion-dollar-investment-in-clean-energy#:~:text=The%20Minns%20Government%20will%20deliver,new%20projects%20to%20the%20grid
61. *Ibid.*
62. "Safeguard Mechanism: International Best Practice Benchmarks", *Department of Climate Change, Energy, the Environment and Water* (Web Page, 2023) https://consult.dcceew.gov.au/safeguard-mechanism-international-best-practice-benchmarks
63. *Competition and Consumer (Gas Market Code) Regulations 2023* (Cth).
64. *Ibid.*
65. *Ibid.*
66. Renju Jose, "Australia to extend gas price cap to at least mid-2025", *Thomson Reuters* (Online, 26 April 2023) https://www.reuters.com/business/energy/australia-extend-gas-price-cap-least-mid-2025-2023-04-26
67. "Compliance guidelines for gas industry as new Gas Market Code takes effect", *ACCC* (Media Release, 15 August 2023) https://www.accc.gov.au/media-release/compliance-guidelines-for-gas-industry-as-new-gas-market-code-takes-effect
68. Lucy Stone, "Coal Royalty Hike Damaging Mining Industry and Investor Confidence, Queensland Resources Council Says", Australian Broadcasting Corporation (Online, 20 September 2022) https://www.abc.net.au/news/2022-09-20/coal-royalty-hike-impacting-queensland-mining-sector-qrc-says/101458878#:~:text=Treasurer%20Cameron%20Dick%E2%80%99s%20decision%20to,tonne%20to%2040%2per%20cent

69. Mark Ludlow, "Qld coal royalty increase hits project pipeline", *AFR* (Online, 1 September 2023) https://www.afr.com/companies/mining/qld-coal-royalty-increase-hits-project-pipeline-20230901-p5e1an
70. Eden Gillespie and Ben Smee, "Queensland budget 2023: coal royalty boom funds $550 energy rebate, free kindergarten and a record surplus", *The Guardian* (Online, 13 June 2023) https://www.theguardian.com/australia-news/2023/jun/13/queensland-state-budget-2023-speech-announced-delivered-by-qld-treasurer-cameron-dick
71. "Petroleum Resource Rent Tax: Review of Gas Transfer Pricing Arrangements Final Report", *Australian Government – The Treasury* (Web Page, 2023) https://treasury.gov.au/publication/p2023-388153
72. "About Arena", *Australian Government – Australian Renewable Energy Agency* (Web Page, 2023) https://arena.gov.au/about
73. *Ibid*.
74. "How We Operate", Clean Energy Finance Corporation (Web Page, 2022) https://www.cefc.com.au/who-we-are/governance/how-we-operate
75. "CEFC Investment Update: 2022–23", *CEFC* (Web Page, 21 August 2023) https://www.cefc.com.au/media/media-release/cefc-confirms-record-renewables-investment-as-race-to-net-zero-gathers-momentum
76. *Ibid.*
77. "Enforcement", *AER* (Web Page, 2023) https://www.aer.gov.au/wholesale-markets/enforcement
78. "*AER v Pelican Point Power Ltd* [2023] FCA 1110", *AER* (Web Page, 2023) https://www.aer.gov.au/publications/reports/compliance/aer-v-pelican-point-power-ltd-2023-fca-1110
79. "Kingston Offshore Wind Farm: The Project", *Skyborn Renewables* (Web Page, 2023) https://kingstonoffshorewindfarm.com.au/the-project
80. "How to Avoid Greenwashing when Offering or Promoting Sustainability-Related Products" (Information Sheet 271, Australian Securities and Investments Commission, June 2022) https://asic.gov.au/regulatory-resources/financial-services/how-to-avoid-greenwashing-when-offering-or-promoting-sustainability-related-products
81. "*Australian Parents for Climate Action v EnergyAustralia*", *Climate Case Chart* (Web Page, 2023) https://climatecasechart.com/non-us-case/australian-parents-for-climate-action-v-energyaustralia
82. Lauren Croft, "EnergyAustralia to face legal action for alleged greenwashing", *Lawyers Weekly* (Web Page, 10 August 2023) https://www.lawyersweekly.com.au/biglaw/37900-energyaustralia-to-face-legal-action-for-alleged-greenwashing
83. *Ibid.*
84. [2022] FCA 1121 (*Tipakalippa*).
85. *Santos NA Barossa Pty Ltd v Tipakalippa* [2022] FCAFC 193.
86. *Ibid.* [38], [67]–[68].

* * *

Disclaimer

The views and opinions set forth herein are the personal views or opinions of the authors; they do not necessarily reflect views or opinions of the law firm with which they are associated.

Darren Murphy
Tel: +61 3 9101 6822 / Email: dmurphy@jonesday.com
Darren is a Partner in Jones Day's Melbourne office and has acted on major energy transactions in Australia and the wider Asia-Pacific region for more than 25 years. He has particular experience in the upstream and downstream energy, mining, power and renewables, and technology sectors. His skills span traditional industries and energy transition, including solar, wind (onshore and offshore), hydrogen, biomass, geothermal, waste-to-energy, and energy storage.
Darren is the Australia-Pacific Chapter Regional Director for the Association of International Energy Negotiators (AIEN) and previously served as co-chair of the Energy Committee of AmCham Singapore and on the Singapore AIEN Committee. He has received extensive recognition in legal directories with recommendations in *Chambers Global*, *Chambers Asia-Pacific*, and *Best Lawyers in Australia* across the areas of energy/projects and corporate/M&A.

Dan Howard
Tel: +61 7 3085 7020 / Email: dhoward@jonesday.com
Dan is a Partner in Jones Day's Brisbane office and focuses his practice on energy and resources law, with an emphasis on electricity, gas, mining, water, and utilities projects. He has been involved in the development of some of Australia's largest electricity, renewables, gas, and mining projects as well as numerous acquisitions and sales of electricity, gas, mining, and infrastructure projects. Dan advises companies on project development, regulatory issues, commodity contracts, and infrastructure arrangements including port and rail, and he is consistently recognised by clients and independent directories for his work, including multiple listings in *Australian Financial Review*'s Best Lawyers. Dan regularly acts for companies on renewable energy projects to secure carbon pollution reduction through renewable energy sources. This work includes renewable project development for wind, solar, hydro, and battery storage.

Sophie Dilda
Tel: +61 7 3085 7042 / Email: sdilda@jonesday.com
Sophie is an Associate in Jones Day's Brisbane office and works with a range of clients on energy and resources matters. She has experience in energy supply agreements, commodity sales contracts, regulatory matters, project development and EPC and LNG contracts, including drafting and advising on commodity sales contracts for sales to Japan, Korea, China and India. Sophie also recently acted in a high-value LNG pipeline construction dispute on behalf of a global engineering and construction firm in the Supreme Court of Queensland.
With a background in commercial litigation, Sophie is well placed to advise clients on avoiding potential, and navigating existing, disputes. Prior to commencing in private practice, Sophie served as Associate to two now retired Judges of the Supreme Court of Queensland – Justice James Douglas in 2019 and Justice Ann Lyons in 2020.

Austria

Thomas Starlinger & Laurenz Götzinger
Schima Mayer Starlinger Attorneys at Law

Overview of the current energy mix, and the place in the market of different energy sources

The Austrian internal energy supply is based on a balanced mix of energy sources.

An estimated one-third of Austria's energy needs are supplied by domestic production and the remainder is imported from abroad. Due to Austria's topography and other factors, 85 per cent of national primary energy production is derived from renewable sources, most notably from hydropower and biomass. Hydrocarbons make up the majority of imports. Therefore, the primary energy sources used to cover Austria's energy consumption are diverse: in 2022, approximately 35 per cent oil, 21.3 per cent gas, 31.6 per cent renewable energies, 7.5 per cent coal, and 2.2 per cent combustible waste were used. Imports account for the remaining 2.4 per cent. As a result of the federal law for a non-nuclear Austria, the production of nuclear energy has been banned in the country since 1978.

According to this, hydrocarbons (oil and gas) still dominate Austria's energy mix. Austria produces oil and gas in economically relevant quantities. The amounts produced cover approximately 10 per cent of the domestic demand annually, while the remainder is imported. The security of supply can be ensured by diversifying the sources of supply. As of 2022, oil imports come from 11 different countries, with Kazakhstan, Libya, and Iraq being the most important. There have been no oil imports from Russia since February 2022.

In 2022, the consumption of oil decreased by 4.2 per cent compared to the previous year. As a consequence of the COVID-19 pandemic, fuel consumption decreased in 2020 and 2021 in comparison to previous years. The consumption of fuel has recently recovered to a normal level as a result of the discontinuity of pandemic-induced curfews.

Concerning natural gas, Austria has always pursued a procurement strategy that is characterised by long-term contracts and a dominant supply country. Therefore, in 2021, Austria imported approximately 80 per cent of its gas from Russia. This dependency, which has grown over decades, could not be changed either immediately or within a short period of time. Moreover, this situation was considered extremely critical, given the fact that the gas flow from Russia has been significantly reduced since mid-2022 as a result of the Russian-Ukrainian war. Therefore, efforts have been intensified to diversify the supply portfolio of gas and to secure gas in storage units for the cold winter period. These efforts have yielded positive results: in 2022, Russian gas imports accounted for an average of 58 per cent.

Furthermore, the war-related circumstances and Austria's longstanding dependency on Russian gas prompted the Austrian Parliament to pass the Gas Diversification Act (*Gasdiversifizierungsgesetz 2022*, "**GDG**") as well as an amendment to the Austrian Gas Act (*Gaswirtschaftsgesetz 2011*, "**GWG**") introducing a strategic gas reserve (please refer to the "Developments in legislation or regulation" section below for more information).

Almost 85 per cent of Austria's domestic primary energy production is based on renewables, firmly establishing Austria at the forefront of this sector. With the government's efforts in promoting renewable energy, several other renewable energy sources, such as wind energy, geothermal energy, and solar energy, have gained significant importance over the past few years. However, the share of renewables in Austria's gross final energy consumption accounted for only approximately 31.6 per cent in 2022.

When analysing the Austrian energy market, it becomes evident that it has become noticeably less competitive compared to previous years: in 2021, 332,985 households and businesses changed their electricity or gas supplier, almost as many as in the record-breaking year of 2019 (354,200). In 2022, only 218,707 changes were made. Consequently, the switching rates for electricity were reduced to 2.7 per cent, and 3.9 per cent for gas.

Changes in the energy situation in the last 12 months that are likely to have an impact on future direction or policy

As a consequence of the onset of the Russian-Ukrainian war in February 2022, Austria's energy situation has changed dramatically. High prices for all kinds of energy sources (gas and electricity as well as biomass and pellets) have triggered political appeals for restrictions on energy consumption and the preparation of emergency measures. For example, the Austrian Gas Price Index (*Österreichische Gaspreisindex*, "**ÖGPI**") rose by 36.4 per cent in September 2022 compared to the previous month. Compared to September 2021, the ÖGPI is 376.5 per cent higher. Generally, Austria's dependency on Russian gas, and the increase in gas and electricity prices triggered by the gas shortage and the price-building mechanism in the European wholesale electricity market, strengthened the political movement to reduce the dependency on hydrocarbons and promote renewable energy sources.

On 31 March 2022, the crisis cabinet of the Austrian federal government declared the so-called "early warning level" (*Frühwarnstufe*) of the emergency plan concerning Austrian gas supply. This stage was declared at a time when there were concrete indications pointing to a deterioration in gas supply. The early warning level primarily involves even more detailed monitoring of the gas market in consultation with market participants (e.g., large consumers) by E-Control, the Austrian regulatory authority for the electricity and gas market.

Developments in government policy/strategy/approach

<u>Clean energy</u>

Austria must fulfil both the European energy policy-related objectives as well as its own energy strategy objectives. In June 2019, the EU enacted a comprehensive update of its energy policy framework to facilitate the transition away from fossil fuels towards "cleaner energy" and to deliver on the EU's Paris Agreement commitments for reducing greenhouse gas emissions. The completion of this new energy rulebook – the Clean Energy for all Europeans Package – marks a significant step towards the implementation of the energy union strategy, adopted in 2015. The programme aims to promote energy efficiency, security of supply, renewable energy development, and emissions reduction at the same time.

To act in line with the new EU energy package, the Austrian government initiated a climate and energy strategy called "#mission2030" in June 2018, setting out strategies to cope with the ambitious 2030 targets. Furthermore, the Austrian federal government aims to achieve a climate-neutral Austria by 2040. Building on this, the current government programme includes the topics of enhancement of renewable energies in Austria's total energy consumption, mobility services, infrastructure measures, and fleet decarbonisation in road transport. However, it should be noted that this government programme did not include concrete steps for achieving many of these objectives.

In December 2018, Austria submitted its integrated national energy and climate plan to the EU Commission, in accordance with Regulation (EU) No 2018/1999 on the Governance of the Energy Union and Climate Action. In June 2019, the EU Commission criticised this plan and thus Austria for insufficient efforts to reduce climate change. Austria's strategies on how to participate in the goal of achieving a reduction of 40 per cent of CO_2 by 2030 were deemed not enough. EU Commissioner Miguel Arias Cañete criticised the lack of concrete information and measures on how Austria intends to reduce its greenhouse gas emissions. Brussels also complained about a lack of information on the necessary investments and their financing, which are needed to improve the climate balance. Other criticisms pertain to non-concrete energy efficiency plans and the lack of integration of agriculture.

Taking into consideration the prior criticism, the Austrian federal government submitted its clear and comprehensive plan to Brussels at the end of 2019, which outlines the measures that Austria will take to achieve its 2030 climate targets.

To reduce oil and gas consumption, the Austrian government launched an initiative for 2023/2024 called "Away from Oil and Gas" to assist households, municipalities, and businesses in transitioning from fossil fuel-based heating systems to renewable alternatives. Approximately 14 per cent of Austria's heating systems rely on oil, accounting for roughly 600,000 installations. As part of the restructuring offensive for both private individuals and companies, €940 million was allocated to this campaign in 2023/2024. Alongside the federal subsidy, the Austrian provinces are also bolstering the switch to environmentally friendly heating systems with their own subsidy programmes.

By 25 August 2023, 20,540 subsidy applications had been submitted, leaving a remaining €602 million available. This initiative, coupled with the ban on using heating oil in newly built homes under provincial building laws, could effectively reduce the prevalence of oil-fired heating systems in Austria.

Developments due to the Russian-Ukrainian war

Due to the Russian-Ukrainian war, the Federal Ministry for Climate Protection, Environment, Energy, Mobility, Innovation, and Technology ("**BMK**") commissioned the Austrian Energy Agency in 2022 to conduct an analysis on Austria's phase-out from Russian natural gas. The aim of this study was to point out strategic courses of action that Austria would have to adopt in order to cease its dependency on Russian gas by a certain point in time. The analysis concluded that Austria's phase-out of Russian gas would be theoretically possible by 2027 if: (i) gas consumption was reduced by 29 TWh by 2030 (this would necessitate a significant reduction in the popular method of gas-powered heating in Austria, resulting in half of all gas-powered heating systems being switched to "green alternatives" by 2030. In addition, the industry would need to heavily incorporate renewable energy sources and implement drastic measures to increase energy efficiency); (ii) gas production from biogas and green hydrogen was increased by 14 TWh by 2030 (by expanding biomethane production in Austria and feeding these volumes into the gas grid, dependency on gas imports could be diminished); and (iii) gas imports from other countries were increased by 20 TWh by 2030, especially gas imports from Norway or imports of liquefied natural gas. However, representatives of the energy industry and the opposition have criticised this analysis as a "nice theoretical calculation", as the Austrian Energy Agency reports to the BMK's Federal Minister, who is part of the association's presidium, and is therefore not entirely independent.

Moreover, the BMK launched the so-called "Mission 11" initiative in September 2022 to reduce Austria's energy consumption by 11 per cent. "Mission 11" focuses on the "little things in everyday life" and therefore includes numerous tips for households to get into the desired "energy-saving mode". In addition, the Austrian federal government introduced the so-called "climate bonus" (*Klimabonus*) in 2022 to address the escalating costs of electricity and gas more effectively. With this bonus, every Austrian resident above the age of 18, holding residence over a period of six months, received €500 from federal funds, regardless of income. In 2023, eligible residents may receive up to €220, depending on the place of residence. However, this measure has faced significant public criticism due to resources being spread too thinly and therefore not addressing the related issue effectively.

Developments in legislation or regulation

Clean energy

Based on Commission proposals published in November 2016, the Clean Energy for all Europeans Package consists of eight legislative acts. All new rules have been enacted since mid-2019; EU countries, including Austria, have between one and two years to transpose the new directives into national law.

The changes will bring considerable benefits from a consumer, environmental, and economic perspective. They also underline EU leadership in tackling global warming and provide an important contribution to the long-term strategy of achieving carbon neutrality by 2050 proposed by the EU.

After the EU Commission presented its climate and energy policy in November 2016, under which all EU Member States would be required to further reduce greenhouse gas emissions and increase energy efficiency by 2030, Austria passed a minor green electricity amendment package, which included several amendments in various Austrian laws. This package simplified administrative procedures and increased their efficiency. It also focused on the promotion of solar systems by adjusting rules and regulations enabling the joint construction and operation of solar system plants at apartment housing that provides an independent electricity power plant for multiple households living in such buildings. Moreover, additional funds were made available for wind power plants, solar system plants, small hydropower plants and biomass plants.

This amendment package, however, did not aim at an overall adjustment of the Austrian renewable funding regime to the EU Commission's guidelines of environmental state protection and energy aid, nor at responding to other structural problems.

To implement the goals of the above-mentioned #mission2030 and to achieve the planned climate neutrality of Austria in 2040, the Austrian Parliament – after a six-month delay – passed the Renewable Energy Expansion Act (*Erneuerbaren-Ausbau-Gesetz*, "**EAG**") on 7 July 2021, with the necessary two-thirds majority. This law was published in Federal Law Gazette 150/2021 on 27 July 2021. Pursuant to constitutional article 103 (1) EAG, most of the provisions contained in the EAG became effective on the day following the date of promulgation. Since the second part of the first main section of this Act contains rules on granting a market premium for the generation of electricity from renewable sources (subsidies), this part is subject to the approval of the EU Commission according to article 108 (3) Treaty on the Functioning of the European Union. The EU Commission approved this part of the EAG at the end of 2021. However, the approval was only granted on the condition that strict requirements are met. Therefore, the EAG had to be amended again in the National Parliament.

The EAG is one of the central instruments for the further evolution of the renewable energy sector. The EAG pursues the goal of increasing electricity production through renewable energy by 27 TWh by 2030 (11 TWh photovoltaics, 10 TWh wind power, 5 TWh hydro-power, 1 TWh biomass). This corresponds to an increase of 50 per cent of the existing renewable power capacity in Austria. To ensure that this increase can be implemented, the EAG provides a suitable subsidy system. Until 2030, €1 billion shall be annually invested in the expansion of renewable energy. Furthermore, the EAG introduces the model of so-called "energy communities". The idea is to have two different systems so that as many people as possible can benefit from it; namely, "renewable energy communities", which enable the joint use of locally produced renewable energy, for example, in the neighbourhood, in the settlement, etc., and "citizen energy communities", which realise the joint use of renewable energy on a supra-regional level by several users joining together to form a virtual community. Moreover, the EAG follows the approach of social justice. Not only are low-income households exempt from green electricity charges, but even households with a low income that do not fall into this category will pay a maximum of €75 a year. More than 550,000 households should benefit from these measures. Further, the EAG provides investment grants to intensify the expansion of green hydrogen and green gas. This is intended to make a significant contribution to the decarbonisation of the industry. In addition, the EAG supports the domestic industry with €500 million to remain competitive and to provide the basis for the "green transformation" of the domestic industry.

The Renewable Heat Act (*Erneuerbaren-Wärme-Gesetz*, "**EWG**"), which is part of the Austrian Heat Strategy, was submitted for appraisal on 14 June 2022 and its entry into force is now eagerly awaited. The initial draft of the EWG outlined plans to phase out coal heating systems by 2035, followed by the complete decommissioning of all fossil-powered gas heating systems by 2040. However, the most recent draft exclusively focuses on the prohibition of fossil-powered central or decentralised heating systems in new buildings by 2024. Some experts in the energy sector have vehemently criticised this shift in approach, denoting it as a regressive step that hinders the achievement of climate neutrality by 2040.

In January 2023, the Austrian government published key points of the eagerly awaited Renewable Energy Expansion Acceleration Act (*Erneuerbaren-Ausbau-Beschleunigungsgesetz*, "**EABG**"). This legislation aims to expedite the growth of renewable energies by implementing a swifter permitting process for projects involving renewable energy, district heating and cooling networks, as well as hydrogen networks. It will also provide improved opportunities for zoning and spatial planning. Furthermore, the EABG will align with the objectives outlined in the REPowerEU Package, establishing designated "Go-To Areas" for renewable energy projects. However, it remains uncertain as to when the Austrian government intends to release a consultation draft of this law.

In February 2023, the Austrian government introduced the consultation draft of the Green Gas Act (*Erneuerbares-Gas-Gesetz*, "**EGG**"). This proposed legislation aims to oblige gas suppliers to gradually replace a certain proportion of natural gas with renewable gas in the future (*Grün-Gas-Quote*) and is designed to drive up the proportion of domestically produced renewable gases, ultimately reducing reliance on imports and bolstering supply security. Starting from 1 January 2024, gas suppliers that provide Austrian end-consumers in exchange for payment will be required to substitute specific portions of the gas volumes supplied to end-consumers in Austria during the preceding year with renewable gas. By 31 December 2030, gas suppliers must replace a minimum of 7.5 TWh of the gas volumes they distribute to end-consumers this year with renewable gases.

The Austrian Electricity Act (*Elektrizitätswirtschafts- und organisationsgesetz 2010*, "**ElWOG**") centrally governs the entire Austrian electricity supply. This legislation came into effect over two decades ago. According to information from the Austrian government, there are plans to replace this law with a new, "more modern" version, tailored to accommodate the increasing prominence of renewable energies. Furthermore, the aim is to address any ambiguities in the current legal framework within the electricity sector through this reform. Additionally, the legislature intends to simplify the relevant existing legislation where possible. Presently, each Austrian province maintains its own Electricity Act in addition to the ElWOG on a federal level. The specific details of this new law remain undisclosed, as no consultation draft is available yet. The timeline for the release of such a draft also remains uncertain.

Developments due to the Russian-Ukrainian war

In March 2022, the Austrian Parliament passed an amendment to the GWG introducing a strategic gas reserve (*strategische Gasreserve*) aiming to secure gas in storage units for the cold winter period. The procurement and management of the strategic gas reserve have been entrusted to the Austrian Market and Distribution Area Manager (*AGGM Austrian Gas Grid Management AG*, "**AGGM**"). AGGM has founded a subsidiary (i.e., *ASGM Austrian Strategic Gas Storage Management GmbH*, "**ASGM**") for the exclusive purpose of procuring the strategic gas reserve. The strategic gas reserve was procured via two tenders and has a volume of 20 TWh, since natural gas is still very popular in household heating and is also used to a considerable extent for district heating. Thermal power generation based on natural gas is also necessary as a backup for power shortages and the stabilisation of the network. As of 1 November 2022, the entire 20 TWh of gas of the strategic gas reserve will be available.

In addition, big gas consumers (industry) are allowed to store 50 per cent of their yearly gas consumption, whereby this quantity does not fall under gas-related emergency measures but is reserved for a specific company. In addition, a further amendment to the GWG (i.e., section 104 (4) GWG) made it possible for gas storage undertakings to administer the storage users fully or partially systematically unused and booked gas storage capacities ("use-it-or-lose-it" principle). Subsequently, storage undertakings must market the withdrawn capacities. This amendment aims to ensure that these capacities are used for security or supply reasons. Moreover, this amendment introduced the possibility that storage undertakings lose their rights as storage undertakings if they violate certain obligations provided for in section 104a/1 GWG (e.g., if they do not withdraw the systematic unused and booked capacity from the storage user according to the process described above or do not market this withdrawn capacity immediately). For example, this was executed against storage undertakings of the gas storage facility Haidach ("**UGS Haidach**"), which is situated in Austria. UGS Haidach is one of the largest natural gas storage facilities in Central Europe and can store up to 2.9 billion cubic metres of natural gas. Furthermore, it is now prescribed that each storage facility located in Austria shall be connected to the Austrian gas grid until the end of 2022. This also applies to UGS Haidach, which has so far only been connected to the German gas grid.

Furthermore, in June 2022, the National Parliament passed the GDG with the objective of facilitating the phase-out of Russian natural gas. This law aims to ensure natural gas diversification and the retrofitting of plants to alternatives using other energy sources. Therefore, a total of €100 million will be made available each year from 2022 to 2025 as compensation for the additional costs incurred. According to the explanatory notes of this law, this solely concerns costs incurred by companies, for example, for pipeline rights when transporting natural gas of non-Russian origin to Austria or when non-Russian natural gas is used, unless climate-friendly, renewable energy sources or district heating are replaced. In addition, this law promotes the retrofitting of energy production plants in the industrial and energy sector that enables alternative operations with energy sources other than natural gas. Details for the use of the funds, the procedure, etc., are to be laid down in guidelines yet to be issued.

In December 2022, the Austrian Parliament passed two laws aimed at reducing the significant profits of oil and gas companies in response to the sharp increase in energy prices caused by the Russian-Ukrainian war, and to restrict the earnings of electricity producers. The Energy Crisis Contribution Act for Electricity (*Bundesgesetz über den Energiekrisenbeitrag-Strom*, "**EKBSG**") introduced the so-called "Electricity-Energy-Crisis-Contribution". This contribution caps the revenues of electricity producers with power plants exceeding 1 MW in capacity at €140 per MWh. The Electricity-Energy-Crisis-Contribution equals 90 per cent of the excess revenue from the sale of electricity generated between 1 December 2022 and 31 December 2023. The maximum revenue increases to €180 per MWh if investments in renewable energy are made in 2022 and 2023. It applies to the sale of domestically generated electricity from various sources, including wind energy, solar energy (both solar thermal and photovoltaic), geothermal energy, hydropower, waste, lignite, hard coal, petroleum products, peat, and biomass fuels except biomethane. The Energy Crisis Contribution Act for Fossil Fuels (*Bundesgesetz über den Energiekrisenbeitrag-fossile Energieträger*, "**EKBFG**") introduced the so-called "Fossil-Fuels-Energy-Crisis-Contribution". This contribution taxes the crisis-related profits of oil and gas companies in the latter half of 2022 and throughout 2023. The average profit from the years 2018 to 2021 will serve as the reference period. If the current profit exceeds this average by more than 20 per cent, a 40 per cent deduction will be applied.

Other developments

On 1 January 2021, by way of an amendment to the ElWOG, the legal basis for the provision of grid reserves (capacity mechanisms) was extended with a view to full compliance with EU State aid rules. The grid reserve introduced is intended to ensure that sufficient generation and consumption capacities are available at all times in order to remove bottlenecks in the transmission grid. Grid reserves are reserves for additional generation capacity or reducible consumption capacity, which can be activated for congestion management. The demand for grid reserves is determined in an annual system analysis by the control area manager in accordance with section 23a ElWOG. It shall be determined until 31 December of each calendar year for a two-year period starting on 1 October of the following calendar year. The grid reserve identified as necessary is to be procured in a transparent, non-discriminatory, and market-oriented tendering process in compliance with section 23b *et seq*. ElWOG, by the control area manager. Upon approval by the regulatory authority, grid reserve contracts shall subsequently be concluded between the control area manager and the successful bidders. In return for the availability of the reserve capacity, the contracted market parties receive a remuneration corresponding to their bidding price. Activations of the units in the grid reserve are remunerated separately. On 28 June 2021, the EU Commission approved Austria's plans to establish a network reserve for the Austrian electricity market under EU State aid rules. The temporary measure will be in force until the end of 2025 and will contribute to safeguarding a secure network operation and a sufficient electricity supply in Austria, without unduly distorting competition in the Single Market.

Judicial decisions, court judgments, results of public enquiries

Decisions of the Austrian regulatory authority E-Control can be challenged with the Federal Administrative Court ("**BVwG**") and an ongoing appeal to the Constitutional Court ("**VfGH**"), the Supreme Administrative Court ("**VwGH**") or both, depending on the issues raised. Fines due to an infringement of energy laws are imposed by the competent district general administrative authority. Such decisions can be challenged in front of the competent Provincial Administrative Court, with subsequent appeal possibilities again to either the VfGH or VwGH.

In the last 12 months, there has been no decision by the BVwG, VfGH or VwGH that has led to serious changes in the field of energy law.

A decision that did not lead to any legislative changes but had an impact on energy law practice is decision OGH 3.3.2022, 5 Ob 114/21g of the Austrian Supreme Court of Justice. The case concerned a wind farm operator who had to reduce the amount of electricity fed into the grid by his wind turbines due to an order of the Austrian Control Area Manager (*Austrian Power Grid AG*, "**APG**") under section 23 (9) ElWOG. The reason for this was that, at certain points, too much electricity was fed into the grid, creating the risk of a blackout due to grid overload. Therefore, APG ordered a reduction in the amount of electricity fed into the grid for the next few hours. As a result, the generator suffered a loss of €12,400 and sued APG for payment. Section 23 (9) ElWOG provides that APG is entitled to issue an order restricting the amount of electricity fed into the grid and thus must pay an appropriate fee for the loss. However, section 23 (9) ElWOG does not explicitly stipulate to whom this order must be issued. In the case at hand, the generator was not directly informed by APG to reduce the quantity of electricity. Instead, the order was received by the responsible distribution system operator. APG argued that a claim for reasonable compensation within the meaning of section 23 (9) ElWOG only exists if the generator is directly ordered to reduce the quantity of electricity. In the end, APG was not successful with this argumentation and the generator received the compensation. The Supreme Court of Justice ruled that the applicability of section 23 (9) ElWOG does not necessarily require that the control area manager address the order directly to the generator. The communication of the content of the order and its simultaneous specification by the distribution system operator also constitutes an order by the Austrian Control Area Manager within the meaning of section 23 (9) ElWOG.

One measure that arose due to the massive increase in energy prices and the accompanying public pressure on politicians is the so-called "electricity-cost-brake" (*Stromkostenbremse*). At the beginning of September 2022, the Council of Ministers (the body of all government members and state secretaries) passed this measure to curb the massive increase in costs for household customers and low-income households. The electricity-cost-brake relieves a household by an average of about €500 per year. The Austrian federal government provides around €3–4 billion, depending on the development of energy prices. The electricity-cost-brake was expected to take effect on 1 December 2022 to remain in place until 30 June 2024. Up to a basic consumption of 2,900 kWh of electricity per year, the energy price is to be set at a maximum of 10 cents/kWh (net), regardless of the number of household members. This means that households will only pay an energy price of about 10 cents/kWh (net) for annual electricity consumption of up to 2,900 kWh. The difference will be compensated as a subsidy. Electricity consumption exceeding 2,900 kWh will be charged to households at the contractually agreed price and thus must be paid in full by the households.

Thomas Starlinger
Tel: +43 1 383 60 510 / Email: thomas.starlinger@sms.law
Dr. Thomas Starlinger is a founding partner at Schima Mayer Starlinger Attorneys at Law.
He advises and represents domestic and foreign companies in all facets of energy law. In addition to regulatory and energy issues, these include, in particular, arbitration proceedings, price revisions and proceedings before national regulatory authorities and the EU Commission. Further focal points of his work include public and real estate law.
After his legal education at the University of Vienna, Thomas Starlinger began his career as a law clerk with the Austrian Supreme Administrative Court before joining the General State Attorney's office. He then spent 20 years with the OMV Group, initially in the central legal department, where he provided legal advice to all corporate divisions both at national and international level (e.g., in Canada and Pakistan). In the course of establishing a holding structure in the OMV Group, he became head of the legal department of OMV Erdgas GmbH. From 2003 to 2007 he was Chief Executive Officer of AGGM Austrian Gas Grid Management AG, the independent distribution system operator of most of Austria's high-pressure gas distribution grid, and from 2004 until 2007, he chaired the committee on legal affairs of the Association of Gas and District Heating Supply Companies (*Fachverband der Gas- und Wärmeversorgungsunternehmungen*). When moving into private practice, Thomas became head of the energy law team at a leading Austrian law firm specialised in business and commercial law and subsequently became a partner at Starlinger Mayer Attorneys at Law and then at Schima Mayer Starlinger Attorneys at Law.

Laurenz Götzinger
Tel: +43 1 383 60 522 / Email: laurenz.goetzinger@sms.law
Mag. Laurenz Götzinger is an associate at Schima Mayer Starlinger Attorneys at Law. He specialises in energy law, with a focus on Austrian and EU energy law, particularly renewable energy law matters, and administrative penal law proceedings related to infringements of Regulation (EU) No 1227/2011 on wholesale energy market integrity and transparency (REMIT).
After completing his legal education at the Faculty of Law of the University of Vienna and following his clerkship in the jurisdictional district of the Higher Regional Court of Vienna, he proceeded to work at Schima Mayer Starlinger Attorneys at Law, moving from paralegal to associate.
Beyond his client work, Laurenz actively contributes to publications covering energy-related topics and participates in domestic events and platforms, speaking on current topics and developments in the Austrian energy market.

Schima Mayer Starlinger Attorneys at Law

Trabrennstraße 2B, 1020 Vienna, Austria
Tel: +43 1 383 60 / URL: www.sms.law

Canada

Christine Milliken, Ryan McNamara, MaryJane Ogbomo &
Rayleigh Minhyu Lee
Blake, Cassels & Graydon LLP

Overview of the current energy mix, and the place in the market of different energy sources

Canada is fortunate to have an abundant energy supply from a wide range of renewable and non-renewable sources. As the second-largest country in the world after Russia, Canada contains 10 provinces and three territories, spans six times zones covering four-and-a-half hours, and stretches from the Atlantic Ocean to the Pacific Ocean and up to the Arctic Ocean. Because of its large size, the energy mix varies across Canada, depending on the natural resources and infrastructure in a particular province or territory.

In 2022, Canada produced an average of 5.0 million barrels of oil per day, an increase by about 100,000 barrels per day from 2021. Canada is the fourth-largest producer and third-largest exporter of oil in the world, with 10% of the world's proven oil reserves (est. 166.7 billion barrels). Canada directs approximately 96% of its oil exports to the United States (U.S.). The majority of Canadian crude oil production occurs in Alberta (82.4%), but crude oil is also produced in the western provinces of British Columbia (B.C.) (0.3%), Saskatchewan (10.4%), and Manitoba (0.8%), and to a lesser extent in Ontario. There are also several producing offshore oil fields located in the northern Atlantic Ocean, off the coast of the Province of Newfoundland and Labrador. Despite Canada's capacity to meet national oil demands through domestic production alone, Canada imported approximately 467,000 barrels of crude oil per day at a total price of $21.5 billion in 2021.

Canada is the world's sixth-largest producer and sixth-largest exporter of natural gas. More than 60% of Canada's natural gas production comes from Alberta. The average daily production of marketable natural gas in Alberta increased in 2022 to 11.0 billion cubic feet per day, the highest production levels since 2010. Canada is the U.S.' number one foreign supplier of natural gas, with approximately 99% of the U.S.' natural gas imports coming from Canada. In recent years, Canadian natural gas exports have declined in overall net value following a steady increase in the supply of natural gas in the U.S. As the U.S. bolsters its domestic supply of natural gas, Canada's energy industry has shifted focus to expanding Canada's liquefied natural gas (LNG) liquefication and export capacities.

Moving water is the most important renewable energy source in Canada, providing approximately 60% of Canada's electricity generation. In 2021, Canada was the second-largest producer of hydroelectricity in the world (11%). It is estimated that Canada is the seventh-largest producer of electricity in the world, generating approximately 657,000 TWh in 2022. Renewable electricity generation increased by 23% between 2010 and 2020, with solar and wind electricity generation having the largest growth. In 2020, 83% of electricity in Canada came from non-greenhouse gas (GHG) emitting sources. Hydroelectricity made up 60%, nuclear energy made up 15%, and other renewable energy sources made up the remaining 8%. Total electricity-related GHG emissions decreased by 68% from 2000 to 2020 because of increased generation from non-emitting sources.

Several provinces, including B.C. and Quebec, rely primarily on hydroelectricity. In recent years, Ontario, Canada's most populous province, engaged in several procurement programmes to acquire electricity from wind, solar and biofuel, with the result that, in 2021, Ontario obtained about 12% of its yearly electricity needs from wind, solar and biofuel, 55% from nuclear power, 23% from hydropower, and only 8% from natural gas (none from coal-fired generation facilities).

Changes in the energy situation in the last 12 months that are likely to have an impact on future direction or policy

Global energy supply crisis and Canada's role

Oil and gas price inflations gradually stabilised following the Russian invasion of Ukraine in February 2022. However, natural gas supply continues to remain low in 2023 due to increased global economic activity post-pandemic and new geopolitical tensions such as the Israel-Gaza conflict. One immediate impact of the conflict was Chevron Corporation's suspension of natural gas production at the Tamar offshore field in October 2023, which, along with other factors, increased European gas prices by 45% compared to the previous week. The closure of the Tamar gas field comes as countries in the northern hemisphere experience falling temperatures, increasing demand for natural gas to heat homes.

In response to global demand for natural gas, Canada continues to build export capacity, cementing its role as a top global natural gas producer. In March 2023, Canada's first Indigenous-owned LNG facility received regulatory approval and awaits the final investment decision to be released in Q4 2023. Canada's first LNG export facility in Kitimat is also expected to be operational as early as 2025. Canada and Romania also signed a $3 billion export development deal with a focus on natural gas exports in September 2023. Canada's role as a potential exporter of natural gas is perceived as both an opportunity to reduce GHG emissions globally by sourcing a lower carbon source of energy and a potential challenge to Canada's commitment to reach net-zero emissions by 2050.

Updates on Canada's pipelines

Canada's energy industry largely depends on pipelines to transport and deliver crude oil, natural gas, natural gas liquids, and refined petroleum products across Canada and to the U.S. Several pipeline project milestones were achieved in 2023. While the Government of Canada announced in February 2022 that the construction of the Trans Mountain (TMX) project was scheduled to be in service by Q3 2023, this completion date has been extended to Q1 2024 after a series of construction-related delays and a contested application to the Canada Energy Regulator for approval of a route modification. This project, once complete, will twin the existing TMX pipeline with 987 kilometres of new pipeline to transport diluted bitumen from Alberta to B.C., adding an additional capacity of 590,000 per day to the TMX pipeline. The TMX project will redirect Canadian oil to B.C., Washington, and California, while making it possible for more oil to be exported to global markets through a tidewater terminal.

The Coastal GasLink (CGL) pipeline project was announced to be 98% complete in late September 2023 and will be mechanically complete by the end of 2023. Once complete, the CGL pipeline will transport natural gas from northeast B.C. to Canada's first LNG export facility, located in Kitimat, B.C. The pipeline will transport 2.1 billion cubic feet per day of natural gas for liquefication and export. Both pipeline projects are significant developments towards introducing Canadian energy to international markets. The Key Access Pipeline System pipeline was also recently completed in Alberta, which is expected to transport a maximum of 350,000 barrels per day of natural gas liquids and condensate.

Electricity supply constraints and nuclear investment

In Ontario, there is a growing perception that the province has insufficient generation capacity to meet future electricity demands. The shutdown of ageing nuclear reactors at the Darlington, Bruce Power, and Pickering stations, either permanently or for refurbishment, has contributed to this perceived short-term capacity constraint as the plants have historically supplied over half of the province's electricity needs. In response, the Government of Ontario approved in June 2023 a plan to extend the operating life of the Pickering station past its expiration date through September 2026, pending approval from the Canadian Nuclear Safety Commission. If approved, the station would be refurbished between 2026 and 2030 to give it another three decades of generation.

Ontario has also been exploring the potential for increased electricity generation through small modular reactors (SMRs). In 2019, the governments of Ontario, Saskatchewan, and New Brunswick signed a Memorandum of Understanding (MOU) to collaborate on advancing SMR development and deployment, which was joined in April 2021 by the Government of Alberta. In April 2023, Saskatchewan and New Brunswick formalised their partnership for the development of SMR technology through a second MOU to further enhance cooperation between the provinces.

The Action Plan proposes to deploy SMRs in three "streams". Stream 1 proposes the construction of a 300 MW SMR project at the Darlington nuclear site in Ontario by 2028, followed by a fleet of units in Saskatchewan, the first of which is intended to be in service by 2032. Stream 2 proposes two advanced reactor designs in New Brunswick at the Point Lepreau site with targeted demonstration units expected to be completed by 2035. Stream 3 proposes a new class of micro SMRs to replace diesel use for remote communities and mines.

In December 2021, Ontario's largest electricity generator, Ontario Power Generation (OPG), announced GE-Hitachi as the preferred technology developer for the Darlington SMR, with the intention to work with GE-Hitachi on design, planning, preparation and licensing of GE-Hitachi's BWRX-300 reactor for deployment at Darlington. In July 2023, the Government of Ontario announced that three additional Hitachi reactors would be installed at Darlington. Saskatchewan's public utility, SaskPower, has aligned with OPG, announcing in June 2022 that it has selected GE-Hitachi as the technology developer for its first SMR. In August 2023, Saskatchewan received $74 million in federal funding for the development of SMRs in the province. Ontario and Saskatchewan position themselves as early movers in the SMR markets by deploying some of the first SMRs.

Developments in government policy/strategy/approach

In Canada, the energy transition is driven by technological innovation, changing consumer preferences, and environmental policy. As a global leader in science and technology in the changing energy industry, Canada is well positioned to become an attractive energy source for international customers. This energy transition involves an increasingly decentralised and diverse platform of energy sources. The energy sector is also working to advance Canada's position as a leader in environmental, social and governance (ESG) performance.

Since 2020, the Government of Canada has made clear efforts to promote and incentivise Canada's improved ESG performance. Canada's strengthened climate plan, released in December 2020, committed to reducing GHG emissions by 30% below 2005 levels by 2030 and to reach net-zero by 2050. On April 22, 2021, the Government of Canada increased its climate ambitions, committing to reduce emissions by 40–45% below 2005 levels by 2030. To meet these goals, the energy sector must focus on clean power and low-carbon fuels, including clean hydrogen, advanced biofuels, liquid synthetic fuels, and renewable natural gas.

Canada's prairie provinces of Alberta and Saskatchewan are expected to lead the growth in renewable energy capacity over the next few years, particularly in wind and solar capacity. This outlook has been tempered by the Government of Alberta's pause in August 2023 of new renewable energy projects with a proposed capacity of over 1 MW. The pause was based on concerns about the use of agricultural lands as project sites, the aesthetic impact of the facilities, and the adequacy of reclamation security. This announcement was subsequently modified so that new applications would continue to be reviewed by the Alberta Utilities Commission (AUC) up to the approval phase, to be resumed in February 2024. The AUC will, in parallel, conduct an inquiry into the issues that motivated the pause and deliver a report to the provincial government to inform future policy development. Despite the uncertainty caused by Alberta's approval pause, Alberta and Saskatchewan have some of the highest photovoltaic potential in Canada and are likely to continue to support solar and wind project development.

Canada's net-zero goals

In March 2022, the Government of Canada released its 2030 Emissions Reductions Plan. This plan outlines a sector-by-sector strategy for Canada to reach its net-zero by 2050 goals. It sets a goal of net-zero electricity across Canada by 2035 by expanding non-emitting energy sources and connecting all regions to clean power.

To this end, the federal budget for 2023 (Budget 2023) provides significant new investment in power generation and transmission. This support will take three forms. First, the federal government will amend income tax rules to create a 15% investment tax credit for investments in clean electricity generation systems, abated natural gas-fired electricity generation (subject to an emissions intensity threshold), stationary electricity storage systems, and interprovincial transmission infrastructure. Second, the budget commits the Canadian Infrastructure Bank (CIB), a federal Crown corporation tasked with supporting revenue-generating infrastructure projects that are "in the public interest", to invest at least $20 billion in major clean electricity and clean growth infrastructure projects. Third, an additional $3 billion will be allocated to Natural Resources Canada to recapitalise the Smart Renewables and Electrification Pathways Program (expanded to include transmission projects), renew the Smart Grid Program to continue support for grid modernisation, and invest in offshore wind development, particularly in Nova Scotia and Newfoundland and Labrador. Canada's latest National GHG Inventory Report for 2021 suggests that Canada is moving towards a cleaner economy, as Canada's GHG emissions rose by 1.8% above 2020 levels in 2021, which was substantially smaller than the Canada's GDP growth of 4.6% over the same period. In order to attract private capital to help build a clean economy, the Government of Canada established the Canada Growth Fund (CGF) in 2022. The CGF aims to reduce emissions and create a net-zero economy by promoting private sector adoption of key technologies such as carbon capture, utilisation and storage (CCUS) and low-carbon hydrogen production technologies.

Carbon capture, utilisation and storage

Canada is a global leader in CCUS technologies, which capture carbon dioxide emissions from fuel combustion, industrial processes, or directly from the air, which is then stored deep underground or used to make new products. Canada's 2021 federal budget proposed several incentives for CCUS projects. In 2022, the Government of Canada provided further details on the CCUS incentive programme, which will take the form of a refundable tax credit for businesses that incur eligible CCUS expenses. From 2022 to 2030, the investment tax credit rates would be set at 60% for investment in equipment to capture carbon dioxide in direct air capture projects, 50% for investment in equipment in all other CCUS projects, and 37.5% for investment in equipment for transportation, storage and use. Those rates will then be reduced by 50% from 2031 to 2040. The federal government in Budget 2023 allocated an additional $520 million to CCUS support and enhanced the investment tax credit for CCUS to include dual-use heat and/or power equipment and water use equipment and expanded eligibility for the tax credit for geological storage of carbon dioxide.

The Government of Alberta remains committed to building a carbon sequestration hub and continues to fine-tune its carbon credit system. In 2021, the Government of Alberta announced that it would grant carbon sequestration rights through a competitive process that would allow successful parties to collect, transport, and permanently store carbon from various emission sources. Since then, the Government of Alberta has reviewed various project proposals and awarded Crown pore space evaluation agreements to 25 projects. As potential project areas are explored, regulatory changes were announced this year to address the potential surplus of provincial carbon credits by accelerating carbon credit expiry and limiting the credit use limit.

Clean Hydrogen Strategy

In December 2020, the Government of Canada released the Hydrogen Strategy for Canada, identifying hydrogen as a critical part of its path towards net-zero and as a strategic priority for Canada over the next 30 years. Hydrogen can be used as a replacement for fossil fuels in transportation, heating buildings, and certain industrial applications. Low-carbon hydrogen is produced in a way that creates far fewer emissions than hydrogen made using traditional methods, for example, using low-carbon electricity to produce hydrogen by electrolysis by splitting water into hydrogen and oxygen atoms using electrolysers. There are several projects already under way in Canadian provinces that utilise hydrogen as a path to net-zero.

In order to respond to the green hydrogen production incentives contained in the U.S. *Inflation Reduction Act*, the Government of Canada announced in Budget 2023 an investment tax credit for clean hydrogen, which will offer tax credits between 15–40% of eligible capital costs for hydrogen production. The amount of the refundable tax credit will vary based on the carbon intensity of the project and is expected to contribute $17.7 billion in support for such projects between 2023 and 2035. The Clean Hydrogen Investment Tax Credit also offers a 15% tax credit for the costs of equipment that converts hydrogen to ammonia to facilitate the transportation of hydrogen to end-use customers. To receive the maximum tax credit rates, certain labour requirements must also be met. This tax credit is part of the federal government's broader strategy to scale Canadian hydrogen production to meet future demand, particularly from hard-to-decarbonise sectors such as long-haul transport, marine and aviation transport as well as heavy industry. The federal government's measures are complemented by provincial strategies to increase hydrogen production.

Alberta

In 2020, Alberta's Recovery Plan and Natural Gas Vision and Strategy articulated an ambition to incorporate hydrogen into Alberta's current portfolio of energy production. The province then released its Hydrogen Roadmap in 2021, which seeks to position Alberta as an important player in global clean economy by leveraging its existing strengths.

Alberta is the largest hydrogen producer in Canada today, producing approximately 2.5 million tonnes of hydrogen per year. Hydrogen is predominantly produced from fossil fuels such as natural gas. Hydrogen from fossil fuels produces carbon as a by-product.

For Alberta to deploy clean hydrogen into the economy, CCUS infrastructure must become widely available for the resulting carbon to be captured and permanently stored; hydrogen produced in this manner is known as blue hydrogen. The province intends to collaborate with industry and partner with other provinces to accelerate blue hydrogen deployment and the advancement of CCUS technology.

Canada's Hydrogen Strategy estimates that by 2050, the Canadian domestic market for hydrogen could reach up to 20 million tonnes per year, and the demand for clean hydrogen in international exports in that timeframe may double that amount. Alberta's capacity for clean hydrogen production is projected to be approximately 45 million tonnes per year, sufficient to satisfy local demand and provide significant export quantities.

Earlier in 2023, the AUC conducted research on hydrogen blending, which integrates concentrations of hydrogen into existing natural gas pipelines and reduces the carbon intensity of delivered fuel. Alberta's Hydrogen Roadmap identifies hydrogen blending at 15–20% by volume into the natural gas distribution network as a key market for its hydrogen ambitions. The Fort Saskatchewan Hydrogen Blending Project is a first-of-its-kind project for Alberta. Because the combustion of hydrogen emits only water, this project will reduce the GHG intensity of the associated natural gas stream.

B.C.

In July 2021, the Government of B.C. released its Hydrogen Strategy, which outlined provincial priorities to scale up the production of renewable hydrogen, establish regional hydrogen hubs and deploy medium-and heavy-duty fuel cell vehicles. B.C. also introduced a discounted electricity rate for renewable hydrogen production to attract new investment. Since more than 98% of B.C.'s electricity is carbon-free and from renewable sources, the province intends to leverage its clean electricity to produce green hydrogen via electrolysis. B.C. also has low-cost natural gas reserves, significant geological storage capacity, and expertise in carbon capture technology, which gives B.C. the potential to produce blue hydrogen. The province established the BC Hydrogen Office to expand hydrogen deployment and to streamline projects from proposal to construction. The Office works with federal and local governments to help attract investment and simplify review and permit processes. There are currently 40 hydrogen projects proposed or under construction in B.C., which represent $4.8 billion in proposed investment in the province.

Through the B.C. Hydrogen Strategy, the province aims to establish long-term, ambitious thresholds for declining carbon intensity, with the intention of ensuring that B.C. remains a world leader in hydrogen and achieves its goal of net-zero emissions by 2050.

Saskatchewan

In September 2021, the Government of Saskatchewan announced several new policy commitments to advance CCUS projects, including advancing opportunities for an infrastructure hub in the Regina-Moose Jaw industrial corridor. A hydrogen and CCUS hub in this region could allow for the development of an entire, commercial-scale hydrogen supply and demand chain in Saskatchewan.

Whitecap Resources and Federated Co-operatives Limited (FCL) signed an MOU to explore opportunities around CCUS, enhanced oil recovery, and carbon dioxide transportation infrastructure. Whitecap and FCL will accelerate the transition to a lower-carbon economy through the proposed CCUS infrastructure, which will enable blue hydrogen production at a commercial scale.

The Government of Saskatchewan continues its development work on a potential hydrogen hub. The Ministry of Energy and Resources, Whitecap Resources, and FCL will support a Foundation Report Study, developed by the Transition Accelerator and the Saskatchewan Research Council, to provide investors with a thorough analysis of commercial-scale hydrogen opportunities and synergies with CCUS infrastructure in Saskatchewan.

Quebec

The Government of Quebec's Plan for a Green Economy 2030 and associated action plan for the years 2021 to 2026, released in November 2020, highlighted green hydrogen and bioenergy as complementary sources of clean energy for the future of Quebec's green economy. In July 2022, Quebec released its 2030 Green Hydrogen and Bioenergy Strategy. Quebec intends to focus on increasing expertise in hydrogen research and development as well as supporting hydrogen projects that meet specific evaluation criteria, with a focus on those projects that support local needs until 2025. From 2026 to 2030, Quebec will support deployment in high-potential sectors, implement an operational framework for large-scale production projects, and continue to support pilot projects, and from 2030 onward, it plans to consolidate consumption in sectors that cannot easily convert to electricity as a source of energy, deploy large-scale projects, and support infrastructure construction.

Examples of recent hydrogen-related projects in Quebec include a low-carbon hydrogen production facility in Bécancour, Quebec, which became the first large-scale low-emissions hydrogen plant in Canada when it entered commercial production in 2021. Another notable hydrogen project in the province is the hydrogen-powered train running on the regional Charlevoix Railway. This pilot project located northeast of Quebec City operated in the summer of 2023 and was the first railway in North America to use hydrogen for locomotive power.

Ontario

In April 2022, the Province of Ontario published a Low-Carbon Hydrogen Strategy as part of its Made-in-Ontario Environment Plan. The plan identifies eight immediate actions to promote the hydrogen economy:

- It proposes to launch a Niagara Falls Hydrogen Production pilot project with Atura Power, a subsidiary of OPG, the province's largest electricity generator. A key agreement to supply zero-cost baseload power to this facility was signed in early 2023, and Atura Power announced in April 2023 that it expects hydrogen production to begin in the second half of 2024.
- Atura Power is to identify hydrogen "hubs" across the province where low-carbon hydrogen demand can be matched by low-carbon hydrogen production leveraging Ontario's electricity grid.
- Bruce Power will launch a feasibility study to explore opportunities to leverage excess energy from the Bruce Nuclear Generating Station for hydrogen production.
- Ontario will work towards reducing electricity rates for hydrogen producers that are able to reduce consumption during system or local reliability events.
- Ontario's Independent Electricity System Operator (IESO) will explore options to support hydrogen storage and grid integration.
- Ontario commits to investing in hydrogen-ready equipment to replace high-carbon emitting equipment such as coal furnaces.
- Ontario proposes amendments to the *Oil, Gas and Salt Resources Act* and the *Mining Act* to enable carbon storage on Crown land.
- Ontario commits to further investment in hydrogen research in partnership with Natural Resources Canada.

In addition to these actions, the provincial government established a Hydrogen Innovation Fund in February 2023 that will invest $15 million from 2023 to 2025 to support the integration of hydrogen into Ontario's clean electricity system, including hydrogen electricity storage. This fund, which will be administered by the IESO, will support new and existing projects as well as feasibility studies to investigate novel application of hydrogen.

Maritimes

On April 11, 2022, the governments of Canada and Nova Scotia announced their intention to position Nova Scotia as a leader in offshore wind and clean hydrogen production. The governments intend to increase offshore renewable energy to meet increasing demands for clean energy and produce hydrogen for export and domestic use. Nova Scotia set targets in September 2022 to offer leases of 5 GW of offshore wind energy by 2030 to support its green hydrogen industry. Over the last two years, a number of new wind projects linked to green hydrogen production have been proposed and approved. For example, in July 2022, EverWind Fuels Company announced that it would build three wind farms in Nova Scotia with an installed capacity of 530 MW to supply clean electricity to its Point Tupper hydrogen and ammonia project. These projects received regulatory approval in February 2023. Likewise, a second hydrogen and ammonia production facility slated for construction in Point Tupper, Nova Scotia was approved in April 2023, signalling that the provincial government is eager to advance its clean hydrogen strategy.

In August 2022, the Port of Belledune located in northern New Brunswick announced an agreement in principle with a developer to design and build a green hydrogen production facility on lands managed by the port. While the project is still in the early stages of development, it is scheduled to come online by 2027, at which point it will export green ammonia fuel to European and North American markets.

The province of Newfoundland and Labrador is likewise seeking to advance wind-hydrogen projects, despite lifting its moratorium on commercial wind energy developments quite recently in August 2022. The Government of Newfoundland selected four bidders in August 2023 to develop wind-hydrogen projects in the province, allowing the bidders to proceed through the province's Crown land application and approvals process. The most advanced projects are expected to commence operation in 2025.

<u>Electricity markets and infrastructure</u>

Canadian provinces have continued efforts to secure new generation and storage capacity in response to growing electricity demands. The IESO, the regulatory body that administers Ontario's electricity market, forecasted that Ontario will require additional capacity to meet its needs in 2025, a need that is projected to grow further towards the end of the decade. In 2022, the IESO announced requests for proposals (RFPs) for 3,500 MW of capacity through its first long-term RFP (LT1 RFP) and a complementary expedited procurement process. Both processes seek to obtain capacity commitments from dispatchable new-build resources. In September 2023, the IESO issued its LT1 RFP for 2,518 MW of total capacity, with a target of procuring 1,600 MW of electrical storage capacity. Successful proponents will be notified in May 2024. A second long-term RFP is set to commence in late 2023, aimed at procuring an additional 1,500 MW of effective capacity. The IESO has also implemented a medium-term capacity procurement process with flexible five-year commitment periods to secure resources with expiring contracts. This process is set to take place every two to three years, with the next medium-term RFP occurring in 2024 or early 2025.

In Saskatchewan, the province announced RFPs to install 10 MW of solar capacity to the provincial electricity grid in 2019 and RFPs for two 200 MW wind energy projects in 2023.

Since 2022, Saskatchewan has added 377 MW of installed wind capacity and 10 MW of installed solar capacity and aims to add an additional 600 MW of wind and solar energy to the provincial electricity grid. In February 2023, New Brunswick issued RFPs to establish 50 MW of energy storage and 220 MW of renewables capacity, including wind, solar, tidal power, and storage solutions proposals. The storage and renewables assets developed through the request are expected to be operational by 2027. B.C. is also expected to launch a call for RFPs in 2024, focusing on proposals that offer renewable, emission-free electricity projects such as wind and solar power, as well as Indigenous-led power projects.

Developments in legislation or regulation

The *Clean Electricity Regulations*

In August 2023, Canada published the proposed *Clean Electricity Regulations* (CER), which, if approved, will prohibit electricity-generating units subject to the CER from emitting more than an annual average of 30 tonnes of carbon emissions per GWh of electricity generated per calendar year. The CER will apply to electricity-generating units that have a generating capacity of 25 MW or more and generate electricity using fossil fuels (including hydrogen gas but not biomass), and units connected to an electricity system subject to the North American Electric Reliability Corporation standards, which includes systems in most Canadian provinces. The CER also introduces registration, reporting and record-keeping requirements. Units subject to the CER will need to submit annual reports including the number of hours that electricity was produced for and the quantity of emissions if the proposed CER is approved in its current form.

The CER is expected to yield a net reduction of 342 million metric tons of carbon dioxide equivalent (CO_2e) between 2024 and 2050 and result in an increase in national annual average electricity payments, relative to its baseline, of $19 to $33 per household in 2050. The federal government is currently seeking feedback on the proposed CER, which will come into force on January 1, 2025.

The *Clean Fuel Regulations*

Canada's *Clean Fuel Regulations* (CFR) came into force in July 2023, designed to encourage investment in low-carbon fuels and new low-carbon technologies in Canada by requiring primary suppliers (fuel producers or importers) to reduce the carbon intensity of liquid fuels produced, used, or imported into Canada. The carbon intensity reduction requirement will start at 3.5 grams of carbon dioxide equivalent per megajoule (gCO_2e/MJ) and will gradually increase to 14 gCO_2e/MJ in 2030. The CFR also establish a credit market to recognise actions to reduce fossil fuel carbon intensity. Regulated parties must create or buy credits to comply with reduction requirements, banking excess credits for sale or use in subsequent compliance periods.

The CFR sparked concern in the energy sector as they are expected to increase production costs for primary suppliers, thereby increasing fuel costs for consumers. At the same time, the regulations are expected to decrease the costs of low-carbon energy sources, such as biofuel and electricity, thereby increasing demand for these sources and reducing overall GHG emissions.

British Columbia

B.C.'s low carbon fuel standard (LCFS) was introduced to reduce the carbon intensity of fuels used in the province. Effective January 1, 2023, the *Renewable and Low Carbon Fuel Requirements Regulation* was amended to: (i) increase the carbon intensity reduction requirement from 20% to 30% by 2030 in the gasoline and diesel fuel pools; and (ii) increase the penalty rate for non-compliance with carbon intensity requirements from $200 per tonne to $600 per tonne. The proposed carbon intensity reduction schedule will linearly increase the target each year from 2023 to 2030 to reach 30% by 2030.

Judicial decisions, court judgments, results of public enquiries

Supreme Court of Canada finds the federal *Impact Assessment Act* unconstitutional

In October 2023, the Supreme Court of Canada (SCC) ruled that the federal *Impact Assessment Act* (IAA), a statute that allows federal regulators to consider potential environmental, health, economic and social impacts of various resource and infrastructure projects, is unconstitutional in its present form. The IAA was enacted in 2019 and triggers federal impact reviews of major projects, such as new oil and gas facilities and pipelines, evaluating those projects based on a range of effects, including climate change. The Alberta Court of Appeal (ABCA) found the IAA unconstitutional because it would allow the federal government to regulate subject matters that do not fall under a federal head of power. The SCC agreed with Alberta that the IAA, as written, could regulate activities in the provincial jurisdiction and overstep its constitutional bounds. While the SCC decision does not strike down the IAA, reference cases where the SCC was asked to provide an advisory opinion are, by convention, treated as binding by the federal government. In a public comment, federal Environment Minister Steven Guilbeault noted that the Government of Canada will follow the SCC's guidance and work to amend the IAA.

Christine Milliken
Tel: +1 403 260 9625 / Email: christine.milliken@blakes.com
Christine Milliken's practice primarily focuses on mergers, acquisitions and divestitures within the oil and gas and renewable energy industries. She has been involved in a broad range of transactions for private and public entities, including domestic and cross-border M&A transactions, share and asset purchase and sale transactions, joint ventures, pipeline and midstream facility development, and commercial arrangements and corporate reorganisations. Christine has significant experience advising clients on general corporate and commercial matters, all aspects of conventional and unconventional oil and gas matters, including liquefied natural gas, pipeline and other midstream project matters, including storage of crude oil by rail terminals, share and asset purchase and sale transactions and due diligence matters.

Ryan McNamara
Tel: +1 416 863 2189 / Email: ryan.mcnamara@blakes.com
Ryan McNamara practises environmental and energy law, providing pragmatic advice to clients to help them navigate the complex and rapidly developing regulatory regimes in these areas. He has experience providing specialist advice on a variety of transactions, including M&A, asset purchases, and private-public partnership transactions. Ryan advises clients on how to effectively comply with a wide range of environmental and energy legislation, including by assisting them with obtaining and amending regulatory approvals and licences.

MaryJane Ogbomo
Tel: +1 403 260 9759 / Email: maryjane.ogbomo@blakes.com
MaryJane Ogbomo's practice focuses primarily on assisting clients with general corporate and commercial energy matters. Her experience includes working on M&A acquisitions, commodities trading and energy derivatives agreements, gas marketing agreements, retail agreements, carbon offset trading, joint ventures, corporate reorganisations, energy infrastructure development, as well as operational and services agreements. As an articling student, MaryJane spent three months working in the legal group at a leading Canadian energy infrastructure company as part of a secondment, researching and advising on upstream/downstream and regulatory matters.

Rayleigh Minhyu Lee
Tel: +1 403 260 9715 / Email: rayleigh.lee@blakes.com
Rayleigh Minhyu Lee's practice focuses on assisting clients with general corporate and commercial matters with a focus on the energy industry. She has assisted clients on a range of matters and transactions, including asset acquisitions and dispositions, corporate reorganisations, and operational and services agreements. Rayleigh's experience includes analysing and drafting corporate charter documents, corporate agreements, and conducting due diligence. As an articling student, Rayleigh spent three months on secondment working in the legal group at a leading Canadian energy infrastructure company.

Blake, Cassels & Graydon LLP
199 Bay St., Suite 4000, Toronto, Ontario, M5L 1A9, Canada
Tel: +1 416 863 2400 / Fax: +1 416 863 2653 / URL: www.blakes.com

Chile

Rodrigo Ochagavía, Ariel Mihovilovic, Vicente Allende &
María Jesús Argandoña
Claro y Cía.

Overview

Energy sectorial regulations in Chile vary significantly depending on whether they are referred to oil, gas or electricity markets. In that sense, a brief overview of the regulation for each of such markets is given, providing context for the developments experienced by the energy industry as a whole in the country, where the most relevant developments have been in the electricity market.

Oil

In Chile, hydrocarbons found in liquid or gas state can only be domestically exploited either directly by the Chilean State or its companies, or by third parties who have been awarded administrative concessions or entered into contracts of special operations with the State (also known as *contratos especiales de operación* – "**CEOPs**"), subject to terms and conditions approved by the President of Chile by means of a supreme decree.

As of this date, Empresa Nacional del Petróleo ("**ENAP**"), a State-owned company, and GeoPark, a private company, are the main domestic producers of crude oil in Chile, and virtually all their oil extraction operations are conducted in the Magellan Basin (both onshore and offshore). Domestic oil production, however, represents a very small fraction of the total amount of oil consumed in Chile; most of it is imported (97%).

Notwithstanding the foregoing, import, export, storage, refinement, transport, distribution, supply and commercialisation of oil or oil derivatives can be conducted by non-State parties; however, as per Decree with Force of Law No. 1 of 1978, any person conducting such activities has to be registered with and become subject to the supervision of the Superintendence of Electricity and Fuel (the "**SEC**"), which monitors and oversees compliance with the laws, regulations and technical standards governing the generation, production, storage, transportation and distribution of liquid fuels, gas and electricity generally. Other than such registration, no concession or special authorisation is required to conduct any such activity.

In this sense, while ENAP is virtually the sole refiner of crude oil in Chile, there are private companies that play significant roles for the storage, transport, supply, and distribution of oil-related products, such as Copec, Shell and Petrobras.

Gas

As for oil, gas can only be exploited and extracted in Chile either by the State or a State-owned company, or by a third party that has either been awarded an administrative concession or has entered into a CEOP with the State. For its part, distribution and transport of gas through pipelines can be conducted directly by private entities, but differently from oil. In addition to the supervision by the SEC, such companies must have also obtained a permanent concession that allows them to: (i) build, maintain, and conduct distribution activities within a given geographical region; or (ii) provide gas transport services through a pipeline or integrated network, as applicable. In any case, to the extent that a concession request complies with the relevant legal, technical, and economic requirements, it cannot be rejected by the authority.

A transport concessionaire must operate under an open access policy, which is understood as the obligation of each transport company to offer its available capacity under the same economic, commercial, technical, and informational conditions to any individual demanding transport services.

Gas transport and distribution prices are freely set through bilateral negotiations between the parties involved, subject to a general maximum profitability limit up to 6% (Annual Cost of Capital) plus a 3% spread. Compliance with this limit is monitored annually by the National Commission of Energy (*Comisión Nacional de Energía* – the "**CNE**"). The Annual Cost of Capital is calculated by the CNE every four years, considering the systemic risk of the activities of public gas distribution concessionaires in relation to the market, the risk-free rate of return, the market risk premium, and an individual risk factor per zone of concession.

Most of Chile's gas distribution infrastructure was constructed during the 1990s, when Chile and Argentina executed bilateral agreements to regulate and promote the export of natural gas from Argentina to Chile, which includes: six natural gas pipelines that connect the local market with Argentina, with two located in the extreme south of Chile (Gasoducto Posesión and Gasoducto Bandurria); two located in central Chile (GasAndes and Gas Pacifico); and two located in northern Chile (GasAtacama and NorAndino).

However, starting in 2004, Argentinean authorities began applying curtailments to the natural gas supply to Chile and halted them in 2007, except for residential consumption – which continued, but at significantly higher prices due to the application of new Argentine export taxes (recently, Argentinean and Chilean entities entered into two separate agreements for gas supply: in one case, uninterrupted supply for the Biobio and Ñuble regions until December 2024; and in the other, for a firm supply of 400,000 m^3 through the northern Atacama and NorAndino pipelines). The absence of Argentinean gas led the Chilean government to promote the development of liquefied natural gas ("**LNG**") terminals in order to restore gas supplies and enhance diversification and security of the country's energy matrix, which resulted in the construction of: (i) GNL Quintero, which started supplying gas in 2009 and was developed by ENAP, together with British Gas, Endesa Chile and Metrogas; and (ii) GNL Mejillones, which initiated operations in 2010 and was developed by Engie Energía Chile S.A. (formerly known as GDF Suez S.A.) and Corporación Nacional del Cobre de Chile (commonly known as Codelco, which is a State-owned mining company and the largest copper producer in the world). On August 6, 2019, Codelco sold its participation in GNL Mejillones to GNL Ameris SpA, a subsidiary of Ameris Capital Administradora General de Fondos.

In addition to the above, the Chilean gas infrastructure also includes three domestic pipelines, each built to reach specific markets (Electrogas (downstream of GasAndres and GNL Quintero), Tal-Tal (downstream of GasAtacama) and Innergy (downstream of Gas Pacifico)), and local distribution networks in the main consumption centres (i.e., the networks of Metrogas (Santiago Metropolitan Region and Region VI), GasValpo (Region V), GasSur (Region VIII), Intergas (Region IX), Gasco Magallanes (Region XII) and Lipigas (Region II)). Finally, the gas infrastructure in Chile also includes "satellite regasification plants", which are local regasification plants that supply gas in areas that are not connected to pipelines in which mainly agriculture-related industries operate; these plants are supplied by tanker trucks.

Electricity

In Chile, the main electricity system is the National Electric System (the "**SEN**"), which supplies electricity to over 97% of the national population, covering more than 3,100 kilometres of the country. Additionally, there are a number of medium and small electricity systems in the regions of Los Lagos, Aysen and Magallanes and one small system on Easter Island, none of which have an aggregate capacity higher than 110 MW.

In the SEN, electricity generation is coordinated by a system operator, the National Electricity Coordinator (the "**Coordinator**"), whose main purpose is to minimise operational costs and to ensure the highest economic efficiency of the system, while meeting all service quality and reliability requirements established by law. Since the introduction of Law No. 20,936, the Coordinator is also in charge of tracking and monitoring competition in the electricity industry and safeguarding open access to electricity transmission. The Coordinator also has a fundamental role in planning the expansion of transmission.

The electricity sector in Chile is divided into three main segments: generation; transmission; and distribution. Regulation regarding energy storage systems was recently added into the General Electric Services Act, which is the main body of law regulating the Chilean electric industry.

In general terms, generation is subject to market competition, while transmission and distribution, given their natural monopoly character, are subject to price regulation. Final customers may be regulated or unregulated depending on their demand. Only unregulated customers may freely choose a provider and freely agree the energy price. Regulated customers are forced to contract with distribution companies and pay them a tariff defined by the Ministry of Energy.

The goal of the Chilean electricity legal and regulatory framework is to provide incentives to maximise efficiency and to provide a simplified regulatory scheme and tariff-setting process that limits the discretionary role of the government by establishing objective criteria for setting prices. The expected result is an economically efficient allocation of resources. The regulatory system is designed to provide a competitive rate of return on investment to stimulate private investment, while ensuring the availability of an electricity service to all who request it.

The generation segment consists of companies that produce electricity and sell their production to distribution companies, unregulated customers, and other generation companies. The transmission segment consists of companies that transmit the electricity produced by generation companies at high voltage. The distribution segment includes electricity supply to final customers at a voltage no greater than 23 kV. In Chile, only generation and distribution companies may commercialise electricity.

Power generation companies satisfy their contractual sales requirements with dispatched electricity, whether produced by them or purchased from other generation companies in the spot market. The principal purpose of the Coordinator in operating the dispatch system is to ensure that only the most cost-efficient electricity is dispatched to customers. The Coordinator dispatches plants in the order of their respective variable cost of production, starting with the lowest-cost plants, such that electricity is supplied at the lowest available cost. Generators balance their contractual obligations with their dispatches by buying or selling electricity at the spot market price, which is calculated by the Coordinator based on the marginal cost of production of the most expensive MWh dispatched.

No concession or particular approval is required to engage in electricity generation (except for the development and operation of geothermal generation facilities, which do require a concession). All generators can commercialise energy through contracts with distribution companies for their regulated customers and unregulated customers, or directly with unregulated customers. All contracts executed between generation and distribution companies for the supply of regulated customers after 2005 must be the result of open, competitive, and transparent auction processes. Generators may also sell energy to other power generation companies on a spot price basis. Power generation companies may also engage in contracted sales among themselves at negotiated prices, outside the spot market. Contract terms are freely determined, except in the case of supply to regulated customers.

The Chilean electricity legal and regulatory framework does not require an electricity concession to build and operate transmission facilities. However, in case it is difficult to process and obtain rights to use or occupy third-party land affected by the transmission facility's layout, transmission companies may request and obtain an electric concession that grants the possibility of enforcing those easements in exchange for proper compensation to the owners of the affected land.

The transmission system is divided into the following main segments: (i) the National Transmission System, the high voltage backbone of the whole system, which supplies energy to the entire electricity demand and permits the connection with other transmission systems; (ii) the Zonal Transmission Systems, which supply energy to regulated customers; and (iii) the Dedicated Transmission Systems, through which unregulated customers receive energy and generators inject the energy produced into the grid. The General Electric Services Act also identifies two other segments, which are much less relevant for the operation of the system; (iv) the Development Zones Systems, destined for areas with resources or conditions of high potential for the production of electricity using a single transmission, which is of general public interest and economically efficient; and (v) the International Systems, destined for exportation or importation of electricity. Of the three main segments, National and Zonal Transmission Systems are considered a public service, and as such, they are subject to open access obligations and a regulated remuneration mechanism based on the amounts invested by the owner in building them and the costs incurred in their maintenance, which are determined by the Ministry of Energy and paid entirely by final customers (whether regulated or unregulated customers). Dedicated Systems obtain their revenues from the tolling agreements freely agreed between the owner and the users (generation companies and unregulated customers), although they are also subject to open access obligations, provided there is sufficient technical capacity.

Concessions are required to engage in electricity distribution. Concessions granted to distribution companies give them a monopoly in their respective concession area, according to which regulated customers are forced to contract with the respective concessionary company, paying a prefixed tariff. The distribution segment is also considered a public service.

Final customers may be regulated if their connected power is equal or less than 5,000 kW, and unregulated if their connected power is higher than 5,000 kW. Regulated customers with a connected power higher than 500 kV, but less than 5,000 kW, have the option to move to the unregulated customers' price regime for a period of four years at least.

Finally, vertical integration in the electricity market is limited by a *prohibition*, according to which companies that own or operate assets of the National Transmission System must not participate directly or indirectly in the power generation or power distribution business, and a *restriction*, by virtue of which the individual participation of generation companies, distribution companies or unregulated customers must not exceed 8% of the investment value of the National Transmission System, and the joint participation of generation companies, distribution companies and unregulated customers must not exceed 40% of the investment value of the National Transmission System. The prohibition and restrictions are included in Article 7 of the General Electric Services Act, which may be amended in accordance with the bill of law known as the "Energy Transition Act" (mentioned below).

Overview of the current energy mix, and the place in the market of different energy sources

The most important sources of primary energy consumed in Chile are oil (26%), biomass (24%) and coal (21%). Most of the fossil fuel sources are imported (approximately 90%), while biomass (firewood) is the main locally produced source of energy.

As to electricity generation, the most important sources are hydroelectricity (24.37%), coal (23.17%) and natural gas (19%). During 2022, non-conventional renewable sources of energy accounted for 31.2% of the electricity produced in Chile, while renewables as a whole (i.e., including hydroelectricity) accounted for 55.6% of the total electricity produced, outperforming thermoelectric generation for the first time in over a decade.

The main consumers of energy in Chile are the industrial and mining sectors (37% jointly), which are supplied with electricity (33%), diesel (26%) and biomass (29%). These sectors are followed by the transport sector (35% of final consumption), which is satisfied almost in its entirety by crude oil derivatives (although with an incipient increase of energy demand due to electromobility policies, especially in public transport), and the commercial, public, and residential sectors, which, combined, account for 24% of the aggregate final consumption. Electricity supplies 23% of the aggregate final energy consumption in Chile.

Changes in the energy situation in the last 12 months that are likely to have an impact on future direction or policy

During the last 10 years, the development of non-conventional renewable energies ("**NCRE**") has seen an explosive growth, which has been accentuated in the last few years. By way of example, NCRE injections accounted for 2,248 GWh in 2012, 17,010 GWh in 2020, 21,688 in 2021, while in 2022 they accounted for 27,759 GWh, representing 31.2% of the total energy generated within such year and becoming the most significant source of energy.

Despite all its positive consequences, this explosive development of NCRE has conducted the Chilean electricity system to an inflection point, mainly because it has not been accompanied by equally fast development of the transmission facilities. In effect, NCRE growth has mainly been due to the construction of solar plants located in the north area of the country, where solar radiation reaches record levels; however, the consumption centres are located in the central zone of Chile, far away from these new plants, which has rendered the transmission facilities insufficient to transport all the energy produced in the north to the centre of Chile, and has led the Coordinator to order curtailments and energy dumping in the northern part of the country to avoid the collapse of the transmission system.

In addition, as the majority of the NCRE recently installed capacity corresponds to solar plants, the energy they produce can only be injected into the system during daylight, which means that all solar-based electricity (which tends to have zero marginal cost) needs to be injected within limited hours. This means that, during daytime hours, there is an abundance of electricity that is injected at a very low spot price, while during nighttime hours the system still needs to resort to fossil fuels to cover the energy demand, and usually at very high spot prices.

The sum of these two effects, i.e., the congestion in transmission lines and the drop in spot market prices in the north of Chile given the excess of solar energy during daylight, has resulted in great decoupling of prices between the zones where the energy is injected and withdrawn by the generators, putting some of them in financial distress, especially those that were awarded with supply contracts to regulated customers at low fixed prices, as such prices are not enough to cover the negative results they are experiencing in the spot market balance, leading them to operate under their costs. As a consequence, the Coordinator has suspended some generators from the spot market's balance and collected the bank bonds posted to secure the payment chain of the system, but such collection has been insufficient to comply with the balances due by the suspended generators, putting pressure on the entire system.

Fortunately, 2023 has seen a level of rainfall in the country that has not been seen for more than 10 years, which has meant higher water reserves that have contributed to reducing price decoupling. However, this sequence of effects has put the authorities on alert, and it is likely that they will take steps towards (i) the promotion and incorporation of NCRE projects that are able to inject energy, ideally, on a 24/7 basis, (ii) the investment and promotion of the expansion of the transmission segment and its compatability with other storage system technologies that allow the injection of energy to be managed according to demand, and (iii) an update of the regulation of bidding processes for the supply of regulated customers.

Developments in government policy/strategy/approach

In February 2022, with the participation of the government, several stakeholders, key participants in the energy sector, universities and the public at large, the Ministry of Energy updated the National Energy Policy (originally issued in 2015 under the title "Energy 2050"), which contains Chile's long-term energy policy, defining what the Chilean energy matrix should be by 2035 and 2050 and the main principles and goals in the road to complete decarbonisation (the "**National Energy Policy**").[1] The update of the National Energy Policy intends to address the current situation and challenges of the Chilean electric system, such as the one described in the previous section, and, among other matters, has set specific goals for the Chilean electric system to achieve, of which the following stand out: (i) 80% zero-emission energy by 2030 in electricity generation and 100% renewable energy by 2050; and (ii) 2,000 MW in energy storage systems in the SEN by 2030 and 6,000 MW by 2050.

Moreover, within the framework of the National Energy Policy and the current status of the Chilean electric system, the Ministry of Energy has developed a short and medium-term agenda[2] to accelerate the process of decarbonisation. Such agenda accounts for the regulatory measures that are already in place or in process (more on that below) and sets the following four pillars in order to implement the necessary intermediate work in the long-term vision for decarbonisation: (i) promotion of storage; (ii) mitigation of risks for suppliers; (iii) operational flexibility; and (iv) political and regulatory actions and urgent projects. Based on such pillars, the government has established the following courses of action:

i. update the National Electric System Coordination and Operation Regulation, in order to include further regulation on storage systems and their operation;
ii. destination of fiscal land adjacent to strategic substations exclusively for storage projects in order to increase the use of renewable energy;
iii. issuance of a Technical Guide that would assist the developers of storage projects in navigating the process of obtaining the environmental evaluation of said projects;

iv. adjustment of the green tax compensation system (i.e., a mechanism that allows thermal generators whose costs of production are above the marginal costs in force at a given time due to green tax application to recover from the system the difference between the marginal costs and their actual costs), in order to better allocate the burden of green taxes in generators that produce more emissions;
v. modernisation of the bidding process for the supply of regulated customers, in order to promote clean and renewable energy projects that are able to supply on a 24/7 basis;
vi. review and adjustment of the technical minimums of thermal power plants, increasing the flexibility of said plants to be turned on or off, in order to respond more quickly and efficiently to the variations on demand that cannot be faced by renewable energy due to its intermittence;
vii. modernisation of the SEN (e.g., through the use of a dynamic line rating ("**DLR**") system rather than the static line rating system that is currently used), in order to improve efficiency in the determination of the transmission lines' transport capacity;
viii. proposition of an Energy Transition Bill whereby electricity transmission will be considered an "enabling sector for the decarbonization process", which would enable the acceleration of processes associated with said segments (this Bill has already been presented to Congress, see section below);
ix. development a Decarbonization Plan for 2030, which will include concrete measures that will allow the materialisation of the goals set forth in the National Energy Policy; and
x. launch of an "Open Season" for the development of urgent works for the expansion of the transmission system, consisting of a design for the fast identification and approval of urgent projects.

Developments in legislation or regulation

The following laws and regulations have been enacted during the last 18 months:

1. Law No. 21,472 (August 2022), also known as "PEC 2", which amends the General Electric Services Act and creates a fee stabilisation fund and a new transitory electricity price stabilisation mechanism for regulated customers. This is the second attempt (the first was Law No. 21,185, also known as "PEC 1") to keep the electricity price for regulated customers stable and ensure a gradual transition in the price increase resulting from the international context (i.e., COVID-19, unstable economic scenario, increasing price of fossil fuels, etc.) and the current changes in the energy transition process on the way to decarbonisation. However, the limits established in PEC 1 were met much earlier than expected, resulting in this new law being enacted. In broad terms, it contemplates the creation of a fund financed by the regulated customers themselves, according to their energy consumption, stabilisation of the electricity price, and a transitory mechanism to cover the gap between the stabilised price paid by regulated customers and the real electricity price paid by distribution companies to their respective suppliers.
2. Law No. 21,505 (November 2022), which incorporates energy storage systems within the regulation of the General Electric Services Act and also creates incentives for electromobility.

Also, please note that the following bills of law (*proyectos de ley*) have been submitted to Congress and are currently under discussion:

1. Bill No. 14,755-08, which proposes, among other matters, to increase the obligation of generation companies to commercialise NCRE up to 40% by 2030, aiming to further accelerate the incorporation of renewable energies in the Chilean electric matrix.

2. Bill No. 15,950-08, which proposes to amend the General Electric Services Act in order to lower the installed capacity limit that allows a regulated customer to become an unregulated customer (currently set at 500 kW). This bill is addressed to small and medium enterprises, because it would allow them to cease to be regulated customers and take advantage of contractual conditions available to unregulated customers, who in recent years have enjoyed lower energy prices than regulated customers.
3. Bill No. 16,078-08, the "Energy Transition Act", which proposes to amend the General Electric Services Act in order to promote a greater deployment of transmission infrastructure that will enable and accelerate the implementation of technologies favouring renewable energies. Some of its specific proposals include: (i) a public and international bidding process for big scale storage system infrastructure; (ii) setting as a new principle of the electric system the promotion of low greenhouse gas emission operation; (iii) further clarifying the rules and regulations applicable to storage systems; and (iv) creating incentives for compliance with power purchase agreements entered for the supply of regulated customers (e.g., payment of compensation in case of default due to a suspension from the spot market).

Judicial decisions, court judgments, results of public enquiries

During the last 12 months there have been several discussions concerning the energy sector, but, given their likely influence not only on the behaviour of electricity-sector actors but also on the future of regulation concerning thereto, we have selected two cases related to the suspension of generators from the balance of injections and withdrawals of energy due to their failure to pay their balances, mostly as a consequence of financial distress caused by the price decoupling generated by the abundance of solar energy, the low prices thereof, and the incapacity of transmission facilities to transport such energy to the consumption centres. Those cases are:

1. *María Elena Solar S.A. liquidation procedure* (23º Civil Court of Santiago, Index No. 497-2023). In January 2023, KfW IPEX-Bank GmbH requested the forced liquidation of María Elena Solar S.A., in its capacity as creditor of the latter and the default in which it had incurred in the context of the project finance granted by KfW IPEX-Bank GmbH for the construction of the Granja Solar Photovoltaic Park, located in Pozo Almonte, Tarapacá Region, Chile. María Elena Solar S.A. was one of the generation companies that was suspended (as of October 1, 2022) from the spot market due to its default of payment obligations thereunder. Such suspension is still in place to this date. Although the judicial process is ongoing, the relevance is that the court has already declared María Elena Solar S.A. bankrupt and applied the special bankruptcy regulation for electric companies set forth in Article 146 *ter* of the General Electric Services Act, which has had very little application over time. As such, in this case, the court, in accordance with the applicable regulation and the reports submitted by the SEC and CNE, considered that the bankruptcy of María Elena Solar S.A. compromises the functioning of the system and therefore ordered it to continue operating its business during the liquidation procedure, and, with the agreement of the creditors' meeting, that its assets be sold as a business unit instead of using other mechanisms available under Chilean insolvency and bankruptcy regulations.
2. *Injunction procedure for the protection of constitutional rights submitted by Ibereólica Cabo Leones II S.A.* (Court of Appeal of Santiago, Index No. 161,398-2022). This procedure was initiated in December 2022 by Ibereólica Cabo Leones II S.A. ("**CLII**") against the Coordinator with the purpose of overruling the resolution issued by the

latter authority rejecting the replacement of CLII by Enerbosch S.A. as a coordinated entity. For context, CLII had been suspended from the spot market, and a month after being suspended it entered into a lease agreement with Enerbosch S.A. by which the latter undertook the operation of the respective photovoltaic plant. In such capacity, Enerbosch S.A. requested to be recognised as the coordinated entity (*coordinado*) before the Coordinator and, consequently, to be included in the balance of injections and withdrawals in replacement of CLII. In the administrative proceeding, the Coordinator rejected such requests, arguing that the company did not provide enough background to assess whether both CLII and Enerbosch S.A. could simultaneously participate in the balance, especially considering that CLII was suspended therefrom. In March 2023, the Court of Appeal of Santiago ruled against CLII's injunction request, confirming that the Coordinator had acted within its powers when rejecting the request to consider Enerbosch S.A. as *coordinado*.

* * *

Endnotes

1. Available at https://www.energia.gob.cl/sites/default/files/documentos/pen_2050_-_actualizado_marzo_2022_0.pdf
2. Available at https://www.energia.gob.cl/sites/default/files/documentos/agenda_inicial_para_un_segundo_tiempo_de_la_transicion_energetica.pdf

Rodrigo Ochagavía
Tel: +56 2 2367 3047 / Email: rochagavia@claro.cl
Rodrigo Ochagavía has been a partner at Claro y Cía. since 2001 and leads the firm's practice in energy and project financing. He has extensive experience in projects, particularly in regulated sectors such as energy, ports, and concessions, as well as a broad practice in M&A and banking and finance. His longstanding relationships with key players in the energy sector and the financing industry give him a deep understanding of the issues at stake in project finance transactions. He has been chosen as a leading Chilean practitioner in Projects, Banking and Finance, Energy and M&A by *Chambers and Partners*, *Latin Lawyer*, *IFLR*, *PLC* and *The Legal 500*, among other publications. He is admitted to practise in Chile (1994).

Ariel Mihovilovic
Tel: +56 2 2367 3002 / Email: amihovilovic@claro.cl
Ariel Mihovilovic joined Claro y Cía. in 2007 and became a partner in 2017. He concentrates his practice in the energy industry and project finance. He has extensive experience negotiating power purchase agreements for both generators and customers, participating in energy auctions sponsored by the government or private companies, as well as in project development, where he has advised sponsors and lenders. He has also actively participated in several M&A and corporate transactions (including the acquisition and financing of several renewable and conventional energy projects).
He has been recognised as a next generation partner in M&A and Banking and Finance by *The Legal 500* and as an active and highly valued practitioner in Corporate and M&A by *Chambers and Partners*.
He is admitted to practise in Chile (2008) and New York (2011), where he worked with Skadden, Arps, Slate, Meagher & Flom (2010–2011).

Vicente Allende
Tel: +56 2 2367 3440 / Email: vallende@claro.cl
Vicente Allende joined Claro y Cía. in 2016. He concentrates his practice in the energy industry, project finance and M&A. He has broad experience in energy regulatory and contractual matters and in the financing and acquisition of energy-related projects in Chile, including extensive experience in distributed generation plants (PMGD). He has also participated in several corporate and M&A transactions, development, and financing of infrastructure projects.
In 2020–2021, he also worked with Latham & Watkins LLP in their New York office. He is admitted to practise in Chile (2016).

María Jesús Argandoña
Tel: +56 2 2367 3075 / Email: mjargandona@claro.cl
María Jesús Argandoña joined Claro y Cía. in 2019 and has mainly focused her practice on litigation, reorganisation and insolvency, project finance and corporate law, mainly in relation to the energy industry. In the last year, she has been actively involved in the liquidation proceeding of María Elena Solar S.A., as well as in other proceedings and operations involving energy and infrastructure projects. She is admitted to practise in Chile (2020).

Claro y Cía.
Avenida Apoquindo 3721, 14th floor, Las Condes, Santiago, Chile
Tel: +56 2 2367 3000 / URL: www.claro.cl

Denmark

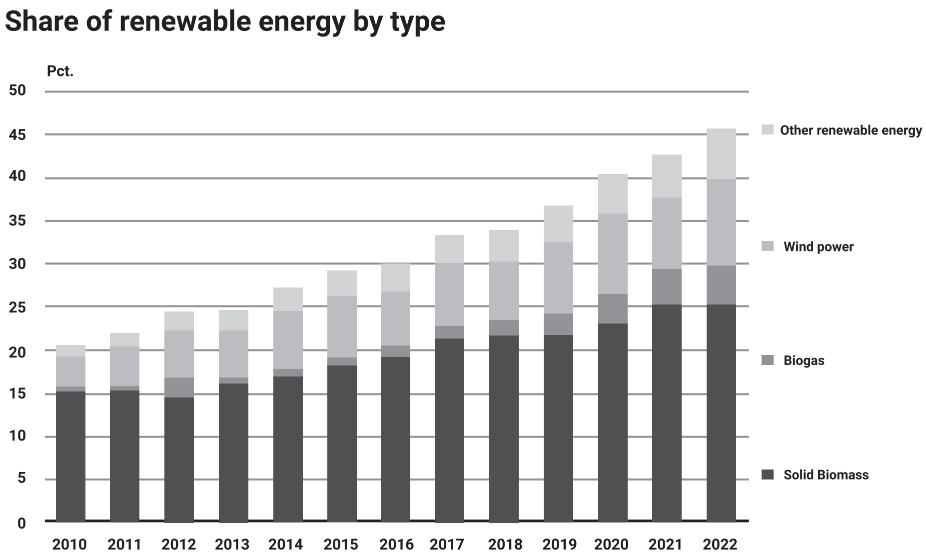
Betina Wichmann & Malthe Siegfried Silverskiold Halckendorff
Lundgrens

Overview of the current energy mix, and the place in the market of different energy sources

In 2022, there was an unprecedented drop in energy consumption in Denmark of 1.7 per cent compared to 2019, when not counting fuel to Danish vehicles, ships and airplanes operated in foreign countries. The reduced energy consumption was probably related to the higher price of natural gases related to the Russian invasion of Ukraine as well as government programmes trying to reduce the consumption of energy.

In 2022, 60 per cent of the total Danish energy demand was met by domestic production,[1] while 45.6 per cent was met by renewable energy sources.[2] Because of climate policies, EU goals and security reasons, renewable energy sources have benefitted from political support, which can be seen in the growing production of energy from these sources. Renewable energy sources consist of wind and solar power, wood, straw, biogas, biodegradable waste, and others (hydropower, geothermal and heat pumps). The biggest of these sources is solid biomass (consisting mainly of wood and straw), which amounts to approximately 25.2 per cent of the total energy consumption in Denmark, while wind power amounts to approximately 10 per cent. Worth noting is the rise in biogas, which has doubled since 2022 and now accounts for approximately 4.5 per cent of the total energy consumption.

See figure 1 for an overview of the energy consumption covered by renewable energies from 1990–2022:



While the production of renewable energies is on the rise, oil is still the main form of energy production, constituting 31.56 per cent of the total energy consumption, while natural gases constitute 12.31 per cent.[3]

Electricity consumption and production

When taking into account electricity production and consumption only, Danish electricity production was 33 TWh, which is 6.9 per cent more than 2021, while Danish electricity consumption was 36.6 TWh, which is 3.6 per cent less than 2021.

Electricity from windmills produced approximately 16 TWh, while solar energy accounted for approximately 1.3 TWh. This is a rise of 18.7 and 68.3 per cent when compared to 2021.[4]

Changes in the energy situation in the last 12 months that are likely to have an impact on future direction or policy

Due to the Russian-Ukrainian war, we have seen higher prices on most forms of energy and political appeals for less energy consumption in private sectors, but with no legislation restricting private citizens. Different measures have been put in place for the public sector to use less energy.

Because of the overall energy situation in Europe, the Danish Government postponed the closure of three Danish power plants and alerted the need for controlled power shutdowns in short periods of time in order to ensure Danish security of supply.

On 1 February 2023, the Danish Energy Agency suspended the offshore open-door procedure until further clarification on the open-door scheme conflict with EU state aid rules. This has led to fewer offshore windmills being established during 2023.

Developments in government policy/strategy/approach

Prime Minister Mette Frederiksen took office on 15 December 2022. The new Government has 88 of the 179 seats in the Danish Parliament and effectively operates as a majority government. It is the first time in more than 40 years that the Social Democrats and the Liberals have formed government together.

As there is traditionally a consensus in Denmark regarding the Danish energy approach, the new Government has not shown to differ from the overall strategy of implementing more renewable energy solutions in Denmark nor its electrification in order to fulfil both the Danish energy strategy objectives as well as EU energy policy-related objectives.

With broad political agreement, it was decided in March 2022 that a contribution would be made to the spread of production and use of Power-to-X in Denmark and that a DKK 1.25 billion Power-to-X public tender process would be implemented in 2023.

On 9 October 2023, the Danish Government made a proposal for securing more solar and wind energy in Denmark. The main objective of the proposal is to make it more attractive to build "energy parks" in Denmark, which means one or more areas in the same geographical area that have annual electricity production from renewable energy of at least 100 million KWh per year. It is intended that these energy parks will be granted special conditions from land protection, permits and municipal planning dispensations.

Developments in legislation or regulation

In April 2023, changes in the Electricity Supply Act and the Electricity Taxation Act were adopted in the Danish Parliament. The main changes include:

- Allowing the establishment of commercially owned direct lines for electricity customers and electricity producers connected to the electricity grid at 10 kV voltage level and above. Direct lines make it possible to connect electricity generation and consumption directly without the electricity being transported through the public grid.
- Adaptation of the prohibition against geographically differentiated consumption tariffs so that it will be possible for collective electricity supply companies, Energinet and grid companies to differentiate between consumption tariffs geographically for electricity consumers connected to the electricity grid at 10 kV voltage level and above.
- Insertion of an authorisation to the Electricity Supply Act to ensure coal on production plants in Denmark.
- Defining renewable self-production and electricity consumers in the Electricity Supply Act.
- Codification of current practice for internal grid and defining the term "internal grid" in the Danish Electricity Supply Act.

In October 2023, the Danish Government presented a catalogue over the legislative proposals they plan to present during the legislative year (October 2023–October 2024). As it is a majority government, the possibility of implementing the proposals as proposed by the Government is fairly high.

The main proposals in the coming year are:

- Amendment of the Act on the Promotion of Renewable Energy, the Act on the Amendment of the Electricity Supply Act, the Act on the Promotion of Renewable Energy and the Electricity Security Act and repealing the Act on subsidies for the promotion of renewable energy in companies' production processes: The purpose of this law proposal is to authorise the Minister for Climate, Energy and Utilities to lay down detailed rules on a fast and simplified application and permit the process for repowering existing offshore electricity production plants, which simplifies and increases the transparency of the application and permit process.

  The proposal clarifies that it is possible for, for example, mortgage credit institutions to register rights to electricity production facilities, such as offshore wind turbine projects located in the exclusive economic zone. Furthermore, an adjustment has been proposed to the administration of a number of price supplement schemes, so that the administration can better handle situations with persistently high electricity prices.

  Finally, the deadline for payment requests for already granted commitments will be extended under VE to the process scheme.
- The Act on strengthened preparedness in the energy sector: This bill will strengthen the level of preparedness in order to prevent and withstand incidents that threaten energy supply and ensure the implementation of EU directives NIS 2 and CER in the energy sector.
- Amendment to the Renewable Energy Promotion Act: This bill aims to create transparency around support payments and equality between land-based and offshore renewable energy plants. The bill includes an abolition of feed-in tariff compensation for future offshore wind farms.

Judicial decisions, court judgments, results of public enquiries

Complaints Board decision 30 May 2023

The state Environmental and Food Complaints Board has rejected a four-year-old municipal approval to expand Sindal Biogas due to a lack of description in the Environmental Impact

Assessment material. It specifically concerns an assessment of the environmental conditions of a pipeline for manure between the supplier and the biogas plant.

The planned biogas plant expansion contributes to a significant CO_2 reduction, which can be read directly in the municipal climate statement. At the same time, it gives Sindal Biogas the opportunity to produce organic grass protein that replaces imported soy from South America and to utilise the residual product for energy production.

Complaints Board decision 23 February 2023

The Environmental and Food Complaints Board has revoked the decision from the Municipality of Horsens regarding environmental approval of a new highway to connect a business area, forcing a renewed municipal consideration.

The Complaints Board found that the Municipality failed to honour the obligations in connection with the proceedings under the Environmental Assessment Act, stating that the environmental objectives and water quality should have been described and that it should have been assessed whether the project would be able to influence these. Furthermore, the Municipality should have assessed whether the project would constitute an obstacle to achieving the set water quality objectives. In connection with this assessment, it is particularly important to consider the possible cumulative effects.

The decision establishes new Danish case practice in stating that deterioration of the condition in relation to pollutant substances must be understood because, when the water environmental quality requirement for a pollutant substance has already been exceeded and the water area is thus in the lowest possible condition, any subsequent increase in the concentration of the substance must be considered a deterioration of the condition of the water area in violation of the Water Framework Directive.

Public enquiries

To address public opposition and pre-empt potential legal challenges to planned energy projects, larger-scale energy initiatives are frequently delayed until they can be formally approved by law.

This approach was notably observed in the case of legislation regarding the establishment of a wind turbine test centre at Østerild in 2009, when the Danish Central Government determined the location for the windmill testing facility through legislation in 2018. This windmill test centre had previously been exposed to great public opposition and also several Complaints Board rejections.

It is anticipated that similar projects, such as the upcoming energy parks, may also undergo this legislative process to mitigate public concerns and ensure their successful implementation.

* * *

Endnotes

1. https://energiwatch.dk/Energinyt/Politik___Markeder/article15598330.ece
2. https://www.dst.dk/da/Statistik/nyheder-analyser-publ/nyt/NytHtml?cid=46139
3. https://www.dst.dk/da/Statistik/emner/miljoe-og-energi/groent-nationalregnskab/energi-og-emissionsregnskaber
4. Energinets miljøredegørelse 2022.

Betina Wichmann
Tel: +45 2524 5132 / Email: bewi@lundgrens.dk

Betina Wichmann advises clients such as renewable energy project developers in relation to government authority negotiations and permit grants and real estate development companies in relation to local planning and development projects.

Some of Betina's key areas are energy and environment issues as well as urban and areal development. Furthermore, Betina has wide experience in planning and environment, including zoning planning, onshore and offshore. Betina also has an extensive knowledge of the entire supply area and experience with the complicated tension field between public regulation and private sector companies.

Betina has extensive experience in advising various players in the market, including companies operating within the wind and solar business, utility companies regarding electricity, water, waste water, district heating and waste, including:

- Project development and Environmental Impact Assessments.
- Institutional investments in renewable energy projects, e.g. solar parks and onshore and offshore wind farms.
- Regulatory matters and construction and procurement law.
- Subsidies schemes.
- Power Purchase Agreements.
- CCS.

Malthe Siegfried Silverskiold Halckendorff
Tel: +45 2396 1319 / Email: mssh@lundgrens.dk

Malthe Siegfried Silverskiold Halckendorff specialised in energy and supply both during and after his education. Since 2021, Malthe has worked as a legal trainee in the Ministry of Climate, Energy and Supply, where he has dealt with Environmental Impact Assessments, wind turbine projects and solar cell projects.

Through Malthe's time both as a legal trainee and as an assistant attorney at Lundgrens, Malthe has also acquired considerable experience within the entire energy and supply area, including water, waste water, electricity and district heating.

Lundgrens

Tuborg Boulevard 12, 2900 Hellerup, Denmark
Tel: +45 3525 2535 / URL: www.lundgrens.dk

Ghana

NanaAma Botchway, Alex Calloway & Ama Aboagye Da Costa
N. Dowuona & Company

Overview of the current energy mix, and the place in the market of different energy sources

Ghana's energy mix consists of a combination of hydroelectric, thermal (predominantly fuelled by natural gas, heavy fuel oil, light crude oil and diesel fuel oil)[1] and renewable energy[2] sources.[3]

Thermal and hydroelectric sources represent approximately 99% of the generation capacity in the country. In 2022, the total power generated was 23,163GWH, of which 8,192GWH (35.4%) was from hydro sources and 14,810GWH (63.9%) from thermal sources.[4] The remaining 162GWH of power generated (representing approximately 0.70% of the total power generated) was sourced from other renewable sources, a significant increase from 2021 and the highest yearly share in Ghana's energy mix to date.[5]

Hydroelectricity is generated from three power plants: the Akosombo and Kpong Generation Stations, operated by the state-owned Volta River Authority ("**VRA**"); and the Bui Generation Station, operated by the state-owned Bui Power Authority ("**BPA**"). The BPA has also completed and commissioned Ghana's first micro-hydropower plant at Tsatsadu in the Volta Region.[6] This is a run-of-river hydro plant that currently has an installed capacity of 45kW.[7]

Thermal power is generated from a combination of private and public sector outputs operated by the VRA and a variety of Independent Power Producers ("**IPPs**"). Three state-owned and six[8] privately owned plants generate energy from the eastern enclave of the National Interconnected Transmission System (the "**national grid**"), while two state-owned and three privately owned plants generate power from the western enclave of the national grid.[9]

Solar and wind energy generation accounts for less than 1% of total power generation in Ghana. The country is, however, taking steps to diversify and increase the weighting of solar, wind and nuclear energy in its energy mix, as described further below.

Generation capacity in Ghana continued to outweigh demand in 2022 as a result of measures taken between 2014 and 2017 to address major energy shortfalls that occurred over the period. By the end of 2022, Ghana had an installed power generation capacity of 5,454MW, with a dependable capacity of 4,843MW[10] and a peak demand of 3,469MW.[11]

Changes in the energy situation in the last 12 months that are likely to have an impact on future direction or policy

Continued demand growth despite economic challenges

In 2022, the external shocks of the Russia/Ukraine crisis and the COVID-19 pandemic exacerbated pre-existing fiscal and debt vulnerabilities, resulting in credit rating downgrades, a loss of access to international capital markets, and the exit of non-resident investors from the domestic bond market.[12] The Ghanaian cedi suffered significant depreciation, losing around 40% of its value against the dollar, inflation hit record highs, and GDP growth slowed from 5.4% in 2021 to 3.2% in 2022.[13]

Despite these difficult economic conditions, electricity demand continued to grow, with an increase of almost 7% in peak system demand over 2021[14] and an increase in total annual consumption of 3.8% from 2021 to 17,547GWH in 2022.[15] Interestingly, Ghana's net electricity export also rose significantly from 2017 to 2022, reaching its highest point of 2,177GWH in 2022.[16]

<u>Launch of the National Energy Transition Framework</u>

As we noted in last year's update, in November 2021, Ghana was amongst 197 nations that adopted the Glasgow Climate Pact following the conclusion of COP26.[17] As a member state of the United Nations Framework Convention on Climate Change, Ghana originally submitted its Nationally Determined Contribution ("**NDC**") target in September 2015, committing to lowering its greenhouse gas emissions by at least 15% by 2030.[18] Ghana reaffirmed this commitment and updated its NDC in accordance with the Paris Agreement in September 2021, shortly before COP26.[19] Ghana committed to implementing 31 mitigation and adaption actions across seven economic areas, which the Government expected to generate an absolute greenhouse gas emission reduction of 64 $MtCO_2e$ by 2030. These measures include the scale-up of renewable energy penetration by 10% by 2030.[20]

The Government's Renewable Energy Master Plan published in 2019, in which it commits to increasing the proportion of non-hydro renewable energy in the national energy generation mix from 42.5MW to 1363.63MW and accumulating carbon savings of about 11 million tonnes of CO_2 by 2030, remains unchanged. Nevertheless, in November 2022, the President launched Ghana's National Energy Transition Framework (the "**Framework**") developed by the National Energy Transition Committee. This is the first policy framework formulated with the specific net-zero target in mind. The Framework, the product of a year-long consultation programme, presents a set of long-term policy recommendations to help Ghana achieve its NDC commitment by decarbonising the energy sector and reaching net-zero emissions by 2070, while ensuring socioeconomic growth and the use of Ghana's natural resources and continuing to meet the increased demand mentioned above.

This Framework is expected to complement existing efforts with new measures, such as increased renewable energy penetration, conversion of thermal plants to natural gas and the integration of nuclear power into the energy mix, as described further below. The Government has established the National Energy Transition Implementation Committee and set up the National Energy Transition Coordinating Office to drive the implementation of the Framework, with participation by key institutions including the Ministry of Energy, Ministry of Transport, and Ministry of Environment, Science, Technology, and Innovation.[21]

<u>Ghana Nuclear Power Programme</u>

In August 2022, Ghana's Nuclear Regulatory Authority announced that Ghana had formally entered Phase 2 of its Nuclear Power Programme.[22] This follows two years after the Integrated Nuclear Infrastructure Review ("**INIR**") Mission, along with follow-up missions in January 2017 and October 2019. An INIR Mission involves a comprehensive peer review by the International Atomic Energy Agency ("**IAEA**") to help member states evaluate their readiness for nuclear power introduction.

As part of ongoing Phase 2 activities, one out of four candidate sites was approved by Cabinet for the development of the first nuclear power plant.[23] Nuclear Power Ghana, the state-owned enterprise ("**SOE**") established to set up and manage Ghana's first nuclear plant, has now started stakeholder engagement to facilitate the acquisition of the preferred site for a nuclear power plant. It has also shortlisted vendors to identify economical and resilient nuclear power technology for this plant.[24]

Increased focus on gas

As noted above, the energy transition agenda and Ghana's NDC commitments are leading to an increased focus on natural gas as a lower-carbon transition fuel, both for electricity generation and industrial heating and transport. The success of this agenda will depend on the finalisation of new offtake arrangements with Ghana's producing fields. Since 2015, gas delivered from the Jubilee and TEN fields has been free to Ghana as agreed under the Foundation Volume Gas Sales Agreement ("**FVGSA**") currently in place between Tullow, the operator, the other contractor parties, and the Ghana National Petroleum Corporation ("**GNPC**"). This arrangement required the contracting parties to deliver 200bcf of "foundation gas" and this obligation was fully satisfied in 2022. The partnership exported approximately 109 million standard cubic feet per day (gross) on average from the Jubilee and TEN fields, fulfilling the remaining committed volumes.[25]

In December 2022, an interim gas sales agreement for 19bcf (gross) was executed between Tullow and the Government of Ghana, valued at USD2.90/MMBtu in line with the price for Jubilee gas referenced in the 2017 Jubilee Plan of Development. In August 2023, Tullow announced that, alongside its joint venture partners, it had agreed an amendment to the interim gas sales agreement to continue the agreement until Q3 2023.[26]

Tullow remains in discussions with the Government of Ghana and the Ghana National Gas Company to finalise the Post Foundation Volume Gas Sales Agreement, which would allow the development of the approximately 2tcf of associated and non-associated gas resources it has identified at Jubilee and TEN,[27] and the Energy Commission has announced that the Eni-operated Sankofa field is expected to continue to supply up to 210mmscf per day to meet demand.[28]

Development of transmission infrastructure

In June 2022, the U.S. Government's Millennium Challenge Corporation ("**MCC**") and the Government of Ghana announced the completion of the five-year, USD316 million MCC-Ghana Power Compact, following the inauguration of the Kasoa Bulk Supply Point ("**BSP**").[29] Under this arrangement, the MCC-Ghana Power Compact invested in new power infrastructure and reforms intended to provide more reliable, affordable electricity to Ghanaians. This included the: construction of the Pokuase BSP and Interconnecting Circuits ("**ICCs**"); Kasoa BSP and ICCs; Low Voltage Bifurcation at Achimota, Dansoman, Kaneshie, Kwabenya, Legon and Mampong; as well as Kanda and Legon Primary Substations and ICCs.

These improvements are very welcome as Ghana has historically recorded high levels of system transmission losses. The total system transmission losses recorded fell from 1,076GWH (5% of the electricity produced) in 2021 to 922GWH in 2022, just 4.1% of the electricity produced, in line with the target benchmark set by the Public Utilities Regulatory Commission ("**PURC**").[30]

The Ministry of Energy is also working to finalise preparations for the Accra-Kumasi transmission line and the Western Corridor Transmission Upgrade Project as well as supporting the "Government Goes Solar" project for implementation.[31]

Other programmes being implemented are the Meter Management System and Geographic Information System for the Electricity Company of Ghana ("**ECG**"), High Voltage Distribution System and Security Lighting infrastructure upgrades in 10 selected markets and economic enclaves in Accra and Tamale, as well as Sustainable Energy Services Centres across select tertiary institutions in Ghana.[32]

Increased distributed generation

We have seen an increased focus on solar projects over the past year. Several off-grid and commercial and industrial solar projects have been developed by the private sector and the sector is receiving significant government support. For example, in May 2022, the Government signed a grant agreement with the African Development Bank ("**AfDB**"), the Climate Investment Fund ("**CIF**") and the Swiss Government Federation to provide USD69.88 million of funding to implement the Scaling-Up Renewable Energy Programme ("**SREP**").[33]

The SREP has three main components, mini-grid, and stand-alone solar home systems for rural off-grid communities, to be implemented by the Ministry of Energy, and net-metered solar PV systems for urban and peri-urban electricity consumers, to be implemented by the Energy Commission. The SREP will involve the deployment of up to 11,000 stand-alone solar home systems within the Lake Volta Region and the overall project cost is estimated at USD85.18 million, comprising the mini-grid and stand-alone solar home component (USD40.29 million) and the net metering component (USD44.89 million).

In September 2023, the Ministry of Energy launched a tender for the design, supply and installation of the 35 solar mini-grids.[34]

Developments in government policy/strategy/approach

Energy Sector Recovery Program

The Government continues to implement the Energy Sector Recovery Program ("**ESRP**"), initiated in May 2019 with the goal of improving financial sustainability within Ghana's energy sector.

The ESRP was structured as a three-phase process, to be implemented over five years. The first phase, which began in 2019, included the setting up of an Energy Sector Recovery Task Force, tasked with reducing shortfalls in energy sector revenue caused by inefficient management. The second phase, which is currently in progress, aims to resolve the difficulties posed by the take-or-pay generation capacity arrangements and the oversupply of gas by matching supply and demand, renegotiating terms with IPPs, completing gas infrastructure, and tackling pricing and policy actions to rationalise tariffs in the power sector. The third phase, which was initially stated to take place before 2023, remains to be developed by the Energy Sector Recovery Task Force for review and approval by Cabinet.

During the first phase of the ESRP, in 2019, the Government imposed a moratorium on the signing of new power purchase agreements ("**PPAs**") and gas supply arrangements and suspended all ongoing negotiations on such agreements until further notice or unless properly exempted by the Government on a case-by-case basis. The Government concurrently announced that it would no longer accept unsolicited proposals in relation to the supply of power or gas.

Since then, the Government has successfully renegotiated terms with six IPPs (Karpower, Cenpower, Early Power, Twin City Energy, AKSA Energy and Cenit). According to the Government, the agreements, when finalised and executed, are expected to offer savings estimated at USD12 billion over the life of the PPAs and more than USD4 billion over the next five years.[35] This is to be achieved through a combination of reduced capacity and energy charges.

However, not all renegotiations have been successful. Ghana Power Generation Company Ltd, an IPP that entered into a PPA with the Government during a period of major power disruptions in June 2015, obtained an arbitration award of USD134 million with interest of USD30 million against the Government in early 2021, for early termination of its PPA, as discussed in the 2021 edition of this chapter.

The general moratorium on the execution of new PPAs remains in place. However, in April 2023, the Energy Commission lifted the moratorium placed on the issuance of new wholesale electricity supply licences in the renewable energy sector in 2020,[36] to facilitate the development of the renewable energy market.

It was a condition of the Extended Credit Facility agreed between the Government and the International Monetary Fund ("**IMF**") in May 2023 that the Government conducted a thorough review of the 2019 ESRP with the assistance of the World Bank, focusing in particular on expediting PPA renegotiations (to reduce the take-or-pay liability), tariff adjustments, improving operational performance of Ghana's SOEs, reforming subsidies to reduce the revenue shortfall, and formulating a strategy for the reduction of transmission losses and improving customer collections.[37]

In June 2023, the Government published an addendum updating the ESRP as a result of this review (the "**June 2023 Addendum**").[38] The June 2023 Addendum noted that the 2019 iteration of the ESRP had not resulted in the expected reduction in cost-recovery shortfalls in the sector and attributed this to "changed circumstances", including a higher-than-expected exchange rate assumption and worse-than-expected SOE performance. To achieve the required reduction in shortfalls, the June 2023 Addendum extended the ESRP by two-and-half years to the end of 2025 and added 21 additional or amended "action items" to be delivered. By way of example, three key amended action items are as follows:

- **Address excess take-or-pay generation capacity costs**: This action item seeks to address excess take-or-pay generation capacity costs by finalising the renegotiation of existing and operational PPAs and rationalising the start date schedule of pipeline projects. For pipeline PPAs, this action item requires the Government to renegotiate contract terms in line with directives issued by the Ministry of Energy and for ECG to ensure that any new contracts do not include government guarantees or tax waivers for projects, are on a take-and-pay basis, and are denominated in Ghanaian cedis. In addition, it requires that, for conventional plants, the generation cost be capped at a cedi equivalent of 10 U.S. cents per kWh (this does not apply to renewables).[39]
- **Redesign of the cash waterfall mechanism ("CWM")**: The June 2023 Addendum updated the CWM introduced in April 2020 to try to ensure equitable and transparent distribution of monthly revenue collections by ECG, based on the invoices submitted by the beneficiaries and the share of each beneficiary in the PURC tariff build-up. The remodelled CWM has two levels: Level A – direct payments from ECG to IPPs; and Level B – payments to SOEs in the power sector and fuel suppliers.[40] In respect of Level B payments, any shortfalls will temporarily be covered by the Ministry of Finance. Based on ECG's renegotiation with the IPPs, a negotiated amount of USD43 million will be made monthly to six IPPs and the remaining amount of ECG collections distributed to the SOEs and remaining generators using the CWM formula. This brought the total amount paid to IPPs and fuel suppliers by the Ministry of Finance

from January to July 2023 on behalf of ECG to USD269 million.[41] The CWM payments will be made by ECG from the single holding account established for this purpose and monthly audits will be published publicly.

- **Private sector participation ("PSP") in electricity distribution**: The June 2023 Addendum proposes that the Government will introduce PSP into the retail distribution segment, focusing on metering, billing, and collections to reduce commercial losses and improve revenue collection to enhance the financial viability of the sector.

Integrated Power Sector Masterplan

In March 2023, the Energy Commission published the 2023 Ghana Integrated Power Sector Master Plan ("**2023 IPSMP**"), an update of the 2019 IPSMP, as required by the ESRP. An objective of the 2023 IPSMP is to identify a long-term "least-regrets" power sector resource plan that will meet Ghana's future electricity demand, through an optimisation of existing and future power plants and other energy systems as well as transmission capability.[42] The 2023 IPSMP identified a diversify geographically strategy as the most favourably ranked and a least-regrets strategy that also conforms to the Government's policy of diversifying generation capacity geographically. The 2023 IPSMP indicates that there is enough capacity (4,763MW) to meet both demand at peak and the planned reserve margin of 18% for 2023 (4,328MW) and 2024 (4,547MW); therefore, additional conventional thermal generation will not be needed until 2026. However, intermittent renewable energy sources will be added to help reduce generation cost in the medium term due to their comparatively low operational cost and reduce fossil fuel dependency. Several recommendations in the 2023 IPSMP include developing new competitively procured solar PV and wind capacity in a slow and gradual manner to increase renewable energy penetration and increase know-how on integration of variable renewable energy plants.

Review of electricity tariffs

In June 2023, in accordance with the June 2023 Addendum to the ESRP and the requirements of the Government's IMF programme, the PURC, which is responsible for setting utility tariffs in Ghana, announced an upward adjustment of 18.36% to the electricity tariffs for all consumer groups. The tariff review was instituted to prevent prolonged power outages and their accompanying negative effects on livelihoods and businesses while trying to minimise the effect of the rate hike on customers as well as the Government's need to generate adequate funds to settle its outstanding debt to the IPPs. The new tariffs have also been attributed to the Ghana cedi/U.S. dollar exchange rate, inflation, electricity generation mix, and the weighted average cost of natural gas.[43]

Green Minerals Policy

In July 2023, Cabinet approved the Green Minerals Policy.[44] The Green Minerals Policy will amend the Mining and Minerals Policy of 2014 to include robust and progressive regimes that would enable the country to reap optimum benefits from lithium and other green minerals. Globally, it is estimated that the lithium industry alone is valued at USD11 billion at the mining stage, with the value of the industry at the highest end estimated at USD7 trillion. The Green Minerals Policy is specifically targeted at adding value to lithium before exporting it.

The new policy is expected to lead to legislative interventions by Parliament, including an amendment to the Minerals and Mining Act, 2006 ("**Act 703**"). For example, while Act 703 sets the rate for mineral royalties at between 3 and 5%, the new policy would see a higher royalty regime for green minerals. Local participation requirement in the green minerals value chain is also expected to increase in contrast to the 10% vested interest the state currently has in mining entities.

National Electric Vehicle Policy

The Ministry of Transport has begun stakeholder engagements on a draft National Electric Vehicle Policy, with engagements starting in August 2023.[45] The draft policy, whose framework was developed in June 2022, is aimed at drawing up a comprehensive implementation plan and an investment strategy to ensure a seamless transition from the use of fossil fuel vehicles to Electric Vehicles ("**EVs**"). Under the Framework, the main means of road transport in the transition is EVs.

According to the International Trade Centre, about 17,660 EVs were imported into Ghana between January 2017 and December 2021.[46] The promotion of the use of EVs in the country is geared at promoting renewable energy and contributing to a reduction in pollution. There is also the need to create demand within the system to take the excess supply of electricity in Ghana.[47]

Developments in legislation or regulation

Proposed Guidelines on Strategic Alliance and Channel Partnership under the Petroleum (Local Content and Local Participation) (Amendment) Regulations, 2021 (L.I. 2435)

In February 2022, the Petroleum Commission introduced proposed amendments to the Petroleum (Local Content and Local Participation) Regulations, 2013 (L.I. 2204) through the Petroleum (Local Content and Local Participation) (Amendment) Regulations, 2021 (L.I. 2435).

Under the existing regulations, if a non-indigenous Ghanaian entity wished to provide goods or services to a contractor, a subcontractor, licensee, or other allied entity in the upstream industry (or the Ghana National Petroleum Commission itself), it is required to incorporate a joint venture with an indigenous Ghanaian company in which the indigenous Ghanaian company holds at least a 10% equity participation.

The new amendment added an additional provision, which provided that, notwithstanding the requirement referred to above, the Petroleum Commission may direct that:[48]

- an indigenous Ghanaian company enters into a "channel partnership agreement" or a "strategic alliance arrangement" with a non-indigenous Ghanaian company; or
- a non-indigenous Ghanaian company enters into a "channel partnership" or "strategic alliance arrangement" with an indigenous Ghanaian company,

where (in each case), the Petroleum Commission is of the opinion that such channel partnership or strategic alliance will deepen local content and local participation and maximise technology transfer to the indigenous Ghanaian company.

The amended regulations define:[49]

- a "channel partnership agreement" as "*an arrangement between an indigenous Ghanaian company and a non-indigenous Ghanaian company including a distributor, a vendor, a retailer, a consultant, a system integrator, an original equipment manufacturer or a value-added reseller to market and sell the products, services or technologies of the non-indigenous Ghanaian company in the country*"; and
- a "strategic alliance arrangement" as "*an arrangement between a non-indigenous Ghanaian company by which the responsibilities of each partner are clearly defined and the partners agree to share resources to undertake a specific mutually beneficial project whilst each retains their independence*".

The amended regulations also define an indigenous Ghanaian company as a company wholly owned by a Ghanaian citizen, with Ghanaian citizens holding at least 80% of executive and senior management and 100% of the non-managerial positions.

In explaining the rationale for the proposed amendments, the Petroleum Commission noted that despite the improvements resulting from the passage and implementation of the Petroleum (Local Content and Local Participation) Regulations, 2013 (L.I. 2204), a value chain analysis of the petroleum upstream sector revealed a deficit in the labour market of essential skills, know-how, and the lack of capacities and capabilities of local companies to support petroleum activities, as well as the domination of non-indigenous firms in critical sectors of the value chain.[50] The Petroleum Commission hopes that the formation of a channel partnership or strategic alliance arrangement will result in a deeper involvement of indigenous Ghanaian companies in day-to-day operations and a greater transfer of skills and know-how, rather than the indigenous Ghanaian company simply being an inactive minority shareholder of the joint venture.

In February 2023, the Petroleum Commission held discussions with the Ghana Upstream Petroleum Chamber ("**GUPC**") on the draft guidelines for strategic alliance and channel partnerships as part of a stakeholder consultation process, but these guidelines have yet to be published.[51]

Net Metering Code

The Renewable Energy Act, 2011 ("**Act 832**") was amended in 2020 to establish a net metering scheme to encourage self-generation of electricity from renewable sources.[52] In May 2023, the Energy Commission published the Net Metering Code, 2023, outlining the implementation guidelines for the net metering scheme. Under the Net Metering Code, customers of a distribution utility with their own renewable energy systems may deliver excess energy generated to the utility in exchange for credit. These credits are then set off against electricity purchased from the utility during the billing period. This is not designed to be an income-generating mechanism, and the distribution utility will not have to make monetary payments. Currently, the net metering scheme introduced by the Net Metering Code is yet to be operationalised.

Proposed power procurement regulations

The June 2023 Addendum to the ESRP notes that the Government proposes to introduce a new legislative instrument for competitive procurement of power from IPPs and that such regulations are currently being prepared. No draft is yet publicly available.

Proposed downstream local content regulations

For several years, there have been proposals for the introduction of local content and participation regulations for the downstream oil and gas sector, which have continued to be discussed in 2022.[53] This major shift in policy may see importation of refined petroleum products into Ghana and their distribution and sales within the country being exclusively reserved for Ghanaian businesses. No specific timelines have yet been set for the passage of these regulations as consultations are ongoing.

Amongst other things, the draft proposed regulations for local content in the downstream petroleum sector require all goods and services to be procured from indigenous Ghanaian companies where possible and limit the award of bulk supply contracts for petroleum products, goods and services to the power generation, upstream petroleum, construction, quarry, and mining industries to indigenous Ghanaian companies.[54]

The current draft regulations do include a saving provision that appears to intend to allow the continued operation of pre-existing, foreign-owned petroleum service providers, provided that their ownership at the passing of the proposed regulations remains the same;[55] however, the effectiveness of this provision remains uncertain.

Proposed review of tax waivers

On 24 November 2022, the Minister of Finance introduced in the 2023 Budget Statement a range of strategic fiscal measures designed to ensure responsible management of expenditures.[56] These include the introduction of a freeze on the issuance of tax waivers for foreign companies and a review of the tax exemptions granted to businesses operating within designated free zones, spanning industries such as mining, oil, and gas. Notably, these entities will not receive any exemptions throughout the entirety of the 2023 fiscal year.[57]

Judicial decisions, court judgments, results of public enquiries

*Springfield Exploration and Production Ltd. ("**Springfield**") v. Eni Ghana Exploration and Production Ltd ("**Eni**") and Vitol Upstream Ghana Ltd ("**Vitol**")*

Eni is the operator of the Sankofa field, located in the Offshore Cape Three Points block, which began production in 2017. Vitol also holds an interest in the Offshore Cape Three Points block, along with GNPC. Springfield is the operator of the Afina field, located in the West Cape Three Points 2 block. The Afina field is not yet producing. Springfield completed a 3D seismic data valuation and drilled one exploration well, Afina-1x, in 2018.

In April 2020, the Minister of Energy issued a directive under section 34 of the Petroleum (Exploration and Production) Act, 2016 ("**Act 919**") requiring the Sankofa field and the Afina field to be unitised, on the basis of a purported finding that the accumulation of petroleum in the Afina and Sankofa fields is connected, extending across both blocks, and requiring Eni, Vitol, and Springfield to enter into a unitisation agreement accordingly.

In July 2020, Springfield commenced proceedings against Eni and Vitol in the Accra High Court, seeking, amongst other things, an order compelling Eni and Vitol to comply with the Minister of Energy's directive to unitise the Sankofa and Afina fields and develop them as one unit, and an order requiring income, profits, and other funds due to Eni and Vitol from exploration and production at the Sankofa field to be paid to Springfield. Eni and Vitol filed applications challenging the capacity of Springfield to enforce the Minister of Energy's directive and to seek reliefs relating to proceeds or revenue from the Sankofa field.

In October 2020, on the basis that the Minister of Energy considered that no significant progress had been made by the parties to voluntarily agree the terms of a unitisation, the Minister of Energy issued a further directive to Eni, Vitol and Springfield imposing terms and conditions for the unitisation.

Eni and Vitol contested both directives, including on the grounds that Springfield had not provided sufficient data or supporting evidence to substantiate a finding that: the Sankofa and Afina fields were in dynamic hydrocarbon communication; the Afina discovery was commercially recoverable (in particular, that commercial flow rates could be achieved); or unitisation would be the appropriate strategy for development to ensure optimum recovery. In January 2021, Eni and Vitol issued a notice of dispute under the Offshore Cape Three Points Petroleum Agreement accordingly.

In April 2021, Eni and Vitol issued judicial review proceedings in Ghana to challenge the legality of the Minister of Energy's directives.

On 25 June 2021, the Commercial Division of the High Court in Accra issued a decision following an application by Springfield for interim relief by Springfield, which ordered that 30% of all revenues accruing to Eni and Vitol from exploration and production activities from the Sankofa field must be preserved and paid into an interest-bearing escrow account until the substantive case is determined.

Having unsuccessfully appealed the High Court's preservation ruling, Eni and Vitol, on 16 August 2021, filed a notice of arbitration under the UNCITRAL rules pursuant to the arbitration provisions of the Offshore Cape Three Points Petroleum Agreement.

Eni and Vitol assert that the Minister of Energy's directives to require unitisation (amongst other matters) constitutes a breach of the stabilisation regime under the Offshore Cape Three Points Petroleum Agreement and a breach of Ghanaian and international law, including that it is contrary to the procedure for unitisation set out in Act 919 and the Petroleum (Exploration and Production) (General) Regulations, 2018 (L.I. 2359) passed thereunder.

Eni and Vitol are seeking damages together with a declaration that the unitisation directive and subsequent related directives by the Minister of Energy represent a breach of its petroleum agreement with Ghana and orders preventing all parties from taking further action to implement the unitisation.

On 21 October 2021, the judicial review application referred to above was dismissed on the basis that the Minister of Energy's directives did not fall short of Ghana's constitutional standard for administrative justice (i.e., the directives were not unfair, arbitrary, and unreasonable).

On 20 June 2022, Springfield filed an injunction application seeking to restrain the Ghana National Petroleum Authority, Ministry of Energy and Ministry of Finance from making further payments to Eni and Vitol for gas supplied to the state from the Sankofa field. The Accra High Court granted the application and directed the injuncted parties to file accounts of all payments they have made to Eni and Vitol to the court.

In September 2022, the High Court dismissed both applications, resulting in Eni and Vitol launching separate appeals against the ruling.

In June 2023, the Court of Appeal upheld the High Court's ruling on Springfield's capacity to commence the proceedings, stating that there was no evidence that precluded Springfield from enforcing its own right pursuant to section 34 of Act 919.

Parliamentary Select Committee report on gas sales agreement between GNPC and Genser Energy

In July 2022, Genser Energy Ghana Limited ("**GEGL**"), a licensed IPP, announced that it had secured funding to undertake various gas midstream projects in Ghana, including a 100km natural gas pipeline to Kumasi, Ghana's second-largest city, a 200mmscfd gas conditioning plant at Prestea, Ghana and a natural gas liquid storage terminal at the Takoradi Port.[58] In connection with the project, GEGL and GNPC entered into a gas sales agreement to provide 329MMBtu of gas to GEGL over a 16-year period. This agreement was initially signed in 2020 and later amended in 2021 following a directive from the Ministry of Energy.[59]

Civil society organisations, including the Africa Centre for Energy Policy ("**ACEP**") and the IMANI Center for Policy & Education ("**Imani**"), raised concerns over the allegedly discounted pricing of gas in this agreement.[60] In response to these concerns, the Parliamentary Select Committee on Mines and Energy announced its intent to investigate these claims in September 2022.

After nearly a year, the Committee concluded its investigation in August 2023. The Committee evaluated testimonies from various stakeholders including GNPC, GEGL, PURC, VRA, Ministry of Energy, ACEP and Imani and concluded that the GEGL agreement should continue to be approved. According to the Committee's report, ACEP and Imani's calculation methods were flawed because they calculated a hypothetical loss using the contractual sum of USD2.79/MMBtu without considering offsets from a capacity charge of USD3.29/MMBtu that GNPC pays back to GEGL.[61]

The Committee's report stated that the agreement would save GNPC USD1.462 billion, and if Ghana had borrowed instead, it would have cost USD1.625 billion.[62] Additionally, the report highlighted several benefits for Ghana, including reduced transmission losses of around USD480 million, particularly when the Ameri plant is relocated to Kumasi and becomes operational. Other advantages mentioned in the report include decreased carbon dioxide emissions, increased port revenue, job creation, extended mine life and the potential for GEGL to expand its operations in Ghana, leading to more employment opportunities for citizens. Despite the Committee's report, however, the GEGL arrangement continues to prove controversial.

* * *

Endnotes

1. 2023 National Energy Statistical Bulletin, p. 11.
2. Although "hydro" is defined as a renewable energy source under section 2 of the Renewable Energy Act, 2011, it is treated separately from other renewable sources, such as solar, in most analyses by the Energy Commission.
3. 2023 National Energy Statistical Bulletin, p. 11.
4. 2023 National Energy Statistical Bulletin, p. 12.
5. 2023 National Energy Statistical Bulletin, pp. 11–12.
6. 2021 Electricity Supply Plan, p. 6.
7. 2023 National Energy Statistical Bulletin, Table 3.2.
8. 2023 National Energy Statistical Bulletin, Table 3.2.
9. 2023 National Energy Statistical Bulletin, Table 3.2, and Electricity Supply Plan for Ghana, Energy Commission – Supply Plan Committee (2021), Table 2.15.
10. 2023 National Energy Statistical Bulletin, Table 3.1.
11. 2023 National Energy Statistical Bulletin, Table 3.6.
12. International Monetary Fund Country Report No. 23/168.
13. World Bank, Ghana Overview.
14. 2023 National Energy Statistical Bulletin, Table 3.6.
15. 2023 National Energy Statistical Bulletin, Table 3.8.
16. 2023 National Energy Statistical Bulletin, Table 3.5.
17. Glasgow Climate Pact, United Nations Framework Convention on Climate Change – Conference of the Parties serving as the meeting of the Parties to the Paris Agreement (13 November 2021).
18. Ghana's intended nationally determined contribution (INDC) and accompanying explanatory note (September 2015).
19. Ghana's Updated Nationally Determined Contribution under the Paris Agreement (2020–2030) (September 2021).
20. Ghana's Updated Nationally Determined Contribution under the Paris Agreement (2020–2030) (September 2021).
21. Ghana's National Energy Transition Framework (2022–2070), p. 1.
22. Ghana's Nuclear Power Programme (Nuclear Regulatory Authority), https://nra.gov.gh/nuclear-power.php
23. 2023 Budget Statement and Economic Policy, para. 653.
24. 2023 Mid-Year Policy Review, para. 488.

25. Kosmos Energy Announces Fourth Quarter and Full Year 2022 Results (Kosmos Energy, 27 February 2023), https://investors.kosmosenergy.com/news-releases/news-release-details/kosmos-energy-announces-fourth-quarter-and-full-year-2022
26. Ghana update: Amendment to Interim Gas Sales Agreement (Tullow Oil, 3 August 2023), https://www.tullowoil.com/media/press-releases/ghana-update-amendment-interim-gas-sales-agreement
27. Tullow Oil PLC, 2023 Half Year Report, https://www.tullowoil.com/application/files/3616/9458/3875/Tullow_Oil_Plc-_2023_HY_Report.pdf
28. 2023 Energy Outlook, Energy Commission, page ii.
29. U.S. Completes $316 Million Investment in Ghana's Energy Infrastructure (US Embassy in Ghana, 1 June 2022), https://gh.usembassy.gov/u-s-completes-316-million-investment-in-ghanas-energy-infrastructure
30. 2023 National Energy Statistical Bulletin, Table 3.7.
31. 2023 Budget Statement and Economic Policy, para. 644.
32. 2023 Budget Statement and Economic Policy, para. 35.
33. 2023 Budget Statement and Economic Policy, para. 644.
34. Government of Ghana/African Development Bank/CIF – Specific Procurement Notice AFDB/MOEN/SREP/GDS/OCB-I/2022/01 and FDB/MOEN/SREP/GDS/OCB-I/2022/02, 22 September 2023.
35. 2023 Budget Statement and Economic Policy, para. 358.
36. Energy Commission Public Notice No. PN057042023 issued 5 April 2023 and accessible at https://www.energycom.gov.gh/newsite/index.php/media-center/public-notices/233-lifting-of-moratorium
37. International Monetary Fund Country Report No. 23/168.
38. Energy Sector Recovery Programme (ESRP) Addendum, Ministry of Energy, June 2023.
39. ESRP Addendum, Ministry of Energy, June 2023, para. 6.1.3.
40. ESRP Addendum, Ministry of Energy, June 2023, paras 6.1.3 and 6.1.18 and Mid-Year Fiscal Policy Review of the 2023 Budget Statement and Economic Policy, para. 57.
41. Mid-Year Fiscal Policy Review of the 2023 Budget Statement and Economic Policy, para. 59.
42. 2023 Integrated Power Sector Master Plan for Ghana, Main Report, Vol 2, pp. iii, 18, 19, 20.
43. Second Quarter Tariff Review Decision for Natural Gas and Electricity (Public Utilities Regulatory Commission, 17 May 2023), https://www.purc.com.gh/attachment/346435-20230517090530.pdf
44. Cabinet approves lithium policy – it covers other green minerals (*Graphic Online*, 7 August 2023), https://www.graphic.com.gh/news/general-news/ghana-news-cabinet-approves-lithium-policy-it-covers-other-green-minerals.html
45. Ministry of Transport engages media on national electric vehicle policy (*B&FT Online*, 11 August 2023), https://thebftonline.com/2023/08/11/ministry-of-transport-engages-media-on-national-electric-vehicle-policy
46. Ghana Electric Vehicles Baseline Survey Report, 2022 (Energy Commission Ghana), p. iv.
47. Concept Note – Drive Electric Initiative (Minerals Commission), https://energycom.gov.gh/files/concept%20note%20Drive%20electric.pdf
48. Petroleum (Local Content and Local Participation) (Amendment) Regulations, 2021 (L.1 2435), Regulation 1.
49. Petroleum (Local Content and Local Participation) (Amendment) Regulations, 2021 (L.1 2435), Regulation 2.

50. Limited Amendments to Petroleum (Local Content and Participation) Regulations, 2013 (L.I. 2204) – Presentation by Kwaku Boateng, Director of Local Content, Petroleum Commission.
51. PC and GUPC hold Discussions on Strategic Alliance and Channel Partnership Guidelines (Petroleum Commission Ghana, 24 February 2023), https://www.petrocom.gov.gh/petroleum-holding-fund-receives-261m-in-second-half-2-2-2-2-2-3-2-2-2-5-2-2-2
52. Preamble of the Renewable Energy (Amendment) Act, 2020 (Act 1045).
53. Govt to reserve downstream petroleum marketing for indigenous companies (*Goldstreet Business*, 4 October 2021), https://goldstreetbusiness.com/2021/business/oil-and-gas/govt-to-reserve-downstream-petroleum-marketing-for-indigenous-companies
54. Draft Petroleum (Ghanaian Content and Ghanaian Participation) Regulations, 2020, Regulation 5(1).
55. Draft Petroleum (Ghanaian Content and Ghanaian Participation) Regulations, 2020, Regulation 35(1).
56. 2023 Budget Statement and Economic Policy.
57. 2023 Budget Statement and Economic Policy, para. 58.
58. Genser secures USD425m for gas midstream projects advancing decarbonization; Trafigura joins as investor, offtaker (*EIN Presswire*, 27 July 2022), https://www.einnews.com/pr_news/583054103/genser-secures-usd425m-for-gas-midstream-projects-advancing-decarbonization-trafigura-joins-as-investor-offtaker
59. Ministry of Energy (2021). Letter to CEO, Ghana National Petroleum Corporation, 10 March 2023.
60. RE: Enquiry into Matters Pertaining to the Gas Sales Agreement between Ghana National Petroleum Corporation (GNPC) and Genser Energy Ghana Limited (GEGL), Africa Centre for Energy Policy & IMANI Center for Policy & Education, August 2023.
61. Unpatriotic Parliamentary Report on GNPC-Genser Gas Deal Riles (The Scarab, August 2023), https://brightsimons.com/2023/08/17/unpatriotic-parliamentary-report-on-gnpc-genser-gas-deal-riles
62. Report of the Committee on Mines and Energy on its Enquiry into Matters Pertaining to the Gas Sales Agreement between Ghana National Petroleum Corporation (GNPC) and Genser Energy Ghana Limited (GEGL), August 2023, p. 11.

NanaAma Botchway
Tel: +233 30 263 2043 / Email: nanaama@ndowuona.com
NanaAma Botchway is the founder and managing partner of N. Dowuona & Company. She has advised on significant investments and divestments in Ghana and other parts of Africa, including the GBP117.7 million acquisition of a multinational utility-scale solar company by Europe's largest renewable energy generator, advising on the proposed acquisition of a Ghanaian oil exploration company by a major international oil company as part of a USD8 billion African asset acquisition and conducting due diligence on the restructuring of a USD135 million loan to a multinational oil and gas service company. Additionally, she has advised companies on regulatory and commercial considerations for operating in Ghana's upstream oil and gas and power generation industries. She also advised the IFC in connection with the Ghana Power Compact with the Millennium Challenge Corporation.

Alex Calloway
Tel: +233 557 889 299 / Email: alex@ndowuona.com
Alex Calloway is an innovative transactional lawyer with a wealth of experience advising multinational corporates, private equity funds, and other investors on complex and high-value acquisitions and disposals, joint ventures, and other global transactions. Alex supports the team in assisting multinationals and other international investors navigate transactions in Ghana and provides advice on English law matters.

In the energy sector, Alex has advised on transactions with a total value of over USD70 billion, including advising: TotalEnergies on its acquisition of Maersk Oil & Gas for USD7.45 billion, settled in Total shares and assumed debt, and its acquisition of Chevron Denmark; Occidental Petroleum on its USD57 billion acquisition of Anadarko and the sale of its interests in the Jubilee and TEN fields to Kosmos Energy and the Ghana National Petroleum Corporation (for USD550 million and USD200 million, respectively); Neptune Energy on its USD3.9 billion acquisition of ENGIE E&P International; ArcLight Capital Partners on its USD900 million acquisition of the SIRGES and FUKA gas pipelines and the St Fergus Gas Terminal; and Rolls-Royce on the sale of its energy gas turbine business to Siemens for GBP1 billion.

Ama Aboagye Da Costa
Tel: +233 30 263 2043 / Email: ama@ndowuona.com
Ama Aboagye Da Costa is an associate at N. Dowuona & Company. Her recent work with the firm includes conducting due diligence on a proposed USD20 million facility to fund commercial solar power projects across Africa by a European clean energy fund and conducting due diligence on the lease of the assets of an industrial petroleum processing facility to enhance its operational capacity. Additionally, she has advised companies on regulatory requirements for operating in Ghana's upstream oil and gas industry and has advised on regulatory and commercial considerations for implementing solar power generation projects in Ghana.

N. Dowuona & Company

Solis House GL-056-7567, Adembra Road, East Cantonments, Accra, Ghana
Tel: +233 20 201 4464 / +233 24 431 9936 / URL: www.ndowuona.com

Greece

Yannis Seiradakis & Eleni Stazilova
Bernitsas Law

Overview of the current energy mix, and the place in the market of different energy sources

Based on the Residual Energy Mix 2022 published by the RES & Guarantees of Origin Operator ("**DAPEEP**"),[1] the energy production mix in Greece for 2022 was formulated as follows: (a) natural gas accounted for 36.5% of total production (including high efficiency combined heat and power ("**HE CHP**") production using natural gas as a fuel source); (b) renewable energy source ("**RES**") production accounted for *c*. 44.8% of total production (solar 13.63%, wind 21.16%, hydropower 8.56% and biomass 1.47% of total production); (c) lignite and other fossil fuels reached 10.7% of total production; and (d) oil contributed only 7.6% of total power production.

Historically, lignite was the backbone of Greece's electricity system for many decades, covering the biggest part of the country's electricity needs. Lignite-powered plants have always been owned by the Public Power Corporation ("**PPC**"), as no private entity has yet undertaken control over such plants in Greece. Over the past 15 years, the share of lignite in meeting the country's electricity demand has significantly decreased. This decrease has been offset by a similar increase in the shares of the power generated from RES and hydropower, as well as imports of electricity mainly from Bulgaria and Turkey. In 2019, Greece reached a decision to terminate the use of lignite by 2028. While, following the outbreak of the Ukrainian war, this gradual fall in the use of lignite-generated power seemed to be brought to a halt for the near future, with Greece initially planning to partially resume the use of lignite as an alternative power source to natural gas, with a 57.7% decrease in lignite-based electricity production in the first eight months of 2023 compared to the same period in 2019, Greece ranks second in terms of reducing the use of solid fossil fuels in electricity production, behind Spain (-69.5%).[2]

Crude oil production in Greece, currently derived from two producing fields in the Northern Aegean Sea (Prinos) by a single oil producer, is gradually falling at the low end of the overall production mix in Greece and is insignificant compared to domestic oil consumption.

Over the past few years, natural gas-fired and RES capacity has seen an increased share in the generation capacity mix, driven by the planned decommissioning of old lignite and oil-fired units (present in the Non-Interconnected System only) and a significant build-out of RES plants.

Until the recent energy crisis, further exacerbated by the ongoing war in Ukraine, natural gas was gradually replacing lignite and oil and was set to play the role of bridge fuel in the decarbonisation process, eventually giving way to RES production, mainly due to being significantly cheaper than oil and more environmentally friendly than any conventional form of energy. By way of background, 2019 saw a record-high growth in national natural gas consumption, which increased by 81% compared to 2014 and by 9.4% compared to 2018. This trend, which continued in 2020 and 2021, shows the rapid penetration of natural gas in the Greek market and its enhanced share in the domestic energy mix. The Greek natural gas demand is fully covered by imported natural gas, which is injected into the National Natural Gas Transmission System ("**NNGTS**"), either through entry points from Bulgaria and Turkey or through the LNG Facility on Revithoussa island. Upstream gas operations are almost non-existent, as production of natural gas is negligibly small compared to the total consumption. To the extent that liquefied natural gas ("**LNG**") was cheaper than pipeline gas, it contributed to the reduction of the cost of electricity production from natural gas, a drop ultimately reflected in the wholesale prices of electricity. At the same time, LNG provided flexibility as a means of risk management for gas suppliers, allowing for smoother and more economical pricing for consumers. Based on data published by the National Natural Gas System Operator (DESFA) S.A. ("**DESFA**"), during 2019–2021, approximately 50% of domestically consumed natural gas was imported as LNG and regasified through the Revithoussa LNG Facility. Overall, the country's natural gas needs were mostly covered by imported natural gas and LNG, primarily from Russia, while other large gas suppliers included Algeria and Turkey. This was largely overturned during the months following the outbreak of war in Ukraine and the sanctions imposed on Russia (including a partial ban on fuel imports), with only 6% of total imports in July 2022 coming from Russia.

In this context, in May 2022, the European Commission released the REPowerEU Plan, in response to the hardships and global energy market disruption caused by Russia's invasion of Ukraine; the main goal of this plan is to end the EU's dependence on Russian fossil fuels.

With the development of renewable energy sources, the country's dependence on Russia for natural gas supplies has reduced. Amid the repercussions of the Ukrainian war, there was a 31% reduction in natural gas demand in the period from August 2022 to March 2023, compared to the same period of 2022, and an 18.2% reduction compared to the average of the previous five years in the same period, thus achieving the target set by EU Regulation 1369/2022 on coordinated demand-reduction measures for gas. At the same time, Greece reduced its dependence on Russian natural gas by 20% (from 40% to 20%).

The entrenched situation resulted in an increase of imports from the United States. More precisely, the United States eventually became Greece's main supplier, with the natural gas imports mix also including imports from Russia, followed by Egypt, Algeria, Norway and Spain.

As part of its "Clean Energy for all Europeans" package, the European Commission adopted an update of the Renewable Energy Directive for 2021–2030 ("**RED III**"), setting the overall EU target for RES consumption by 2030 at 32% and an energy-efficiency target of at least 32.5%, with an upwards revision clause by 2023. Previously, decarbonisation of the national energy market had been declared a top priority under Law 3851/2010, transposing Directive 2009/28/EU, which set the target of increasing the share of RES in gross final energy consumption to 20%, and in gross energy consumption to 40% by 2020.

In September 2023, in the context of the revision of RED III, the EU Parliament reached a deal to raise the share of renewables in the EU energy mix in an effort to further accelerate its shifting away from fossil fuels. Based on this bill, a new target is set, providing that at least 42.5% of energy produced in the EU shall be generated from renewables by 2030, a target significantly exceeding the current target of 32%.

In the transport sector, RED III introduces an incentive concerning an increase in the use of renewable energy, so as to contribute to a 14.5% reduction in greenhouse gas emissions by 2030. This target is expected to be achieved by increasing the share of advanced biofuels and introducing higher quotas for renewable fuels of non-biological origin, such as hydrogen.

Changes in the energy situation in the last 12 months that are likely to have an impact on future direction or policy

The COVID-19 pandemic undoubtedly affected every commercial activity worldwide, causing the suspension of business activities and projects across all sectors for a significant part of 2020. In the energy sector, oil prices plunged to a record low, while national lockdowns imposed by governments around the globe, including the Greek Government, had a game-changing impact on the power and natural gas levels of demand. In 2020, the energy sector in many jurisdictions was affected by the COVID-19 pandemic and slump in oil prices, and some of those impacts continued in 2021.

Separately, since the early implementation stages of the EU Target Model in November 2020, market turbulence has overall led to higher wholesale energy prices. This hike has been passed on to low- and medium-voltage consumers by all power suppliers as they ceased to provide fixed-price contracts, and instead included wholesale market-related clauses in their supply contracts. This dramatic price adjustment was first applied in August 2021; however, by early 2022, the majority of energy consumers were suffering significant increases in their electricity bills. Since early 2022, global energy prices have risen sharply, primarily as a result of the invasion of Ukraine, followed by measures adopted by the EU in an effort to limit dependence on Russian natural gas. Apart from this war-induced rise, the energy market has also been materially disrupted by the growing energy demand in Asia and limited shale production in the United States. The turbulence in natural gas prices in Europe has had a direct impact on power production, which remains largely based on natural gas (exceeding a 40% rate).

This escalating crisis invoked strong reactions particularly from consumers and eventually resulted in the implementation of drastic measures by the Greek Government during the summer of 2022, which were extended during summer of 2023, including: (a) the enforcement of certain legislative amendments enabling enhanced access to natural gas and LNG (e.g. DESFA's right to temporarily lease LNG ships, and capacity enhancement and simplification of LNG loadings at the Revithoussa LNG Facility); (b) the temporary suspension as of August 2022 of the price adjustment clauses that linked retail to wholesale prices and streamlining of the power suppliers' switch process (Article 138 of Law 4951/2022); and (c) from 1 July 2022 to 31 December 2023, the introduction of price caps on the wholesale market for lignite plants, RES and hydro plants (Article 122 of Law 4951/2022). This was followed by the Regulatory Authority for Energy's ("**RAE**") decisions regulating the methodology[3] and specific price caps per each form of production plant.

Further, a mechanism was introduced for the clawback of so-called "windfall profits" of wholesale market participants generated before July 2022. All excess profits reclaimed are deposited into the national Energy Transition Fund, which in turn funds the financial support schemes aimed at alleviating consumers' economic burden. The Government's approach is in line with the ongoing discussion at the EU level, which, with a view to protecting citizens from soaring energy prices that have driven inflation across the continent to record highs, has so far favoured profit clawback mechanisms.

Another key development driven by the recent energy crisis is the partial revival of Greece's coal mining industry by 50% and the extension of the operation of all lignite-fired power plants to 2028, as a measure to ensure security of supply in light of the fluctuations in natural gas capacities and prices. By way of background, as part of the country's decarbonisation plan, launched largely by the latest National Plan for Energy and Climate ("**NPEC**") in 2020, a central priority has been the gradual shutdown of all but one of its coal-fired plants by 2023 and the conversion of a new, more efficient lignite-fired unit (Ptolemaida 5) and cleaner fuel by 2025. To ensure a fair development transition of the lignite areas in Western Macedonia and Megalopolis, a three-pillar plan was announced: employment protection; compensation of the socio-economic impact of the transition; and energy self-sufficiency of lignite areas. Greece is a pioneer in Europe for the "just transition" plan related to lignite areas, which identifies five development areas, including (i) clean energy, (ii) industry, small industry and trade, (iii) smart agricultural production, (iv) sustainable tourism, and (v) technology and education.

In response to the energy crisis and in order to tackle a potential deficiency in natural gas in the near future, several new floating terminal plans are ramping up in the Greek market, adding to the long-expected Alexandroupolis floating storage and regasification unit ("**FSRU**"), an LNG terminal whose construction began in 2022, set to start operation in early 2024. The Alexandroupolis FSRU will comprise an offshore floating unit for the reception, storage and regasification of LNG and a transmission system for the shipping of natural gas into the NNGTS, thus securing new natural gas quantities for the supply of Greek and regional Southeastern European markets. Gastrade, the project company, has obtained a third-party access exception, following a market test process carried out in cooperation with RAE. The Alexandroupolis FSRU, once completed, will be the second LNG terminal operating in Greece, together with the Revithoussa LNG Facility (the latter being part of the NNGTS). In particular, completion of Dioryga Gas, a new LNG Facility in Corinth developed by the Motor Oil group, is expected to increase the capacity of the Greek natural gas system by 80%, thus strengthening the country's security of supply, while the system's capacity will be further enhanced by the Argo FSRU, a terminal to be developed in Volos by Mediterranean Gas.

Meanwhile, in terms of natural gas infrastructure, in less than a year of commercial operation, the IGB pipeline has become a key element in Greece's and Bulgaria's path towards energy diversification, security and independence. Over 82% of the total capacity for the next year has already been committed, and there are plans for an expansion to further strengthen the role of Bulgaria and Greece on the regional energy map.

A recurring situation peaking several times during the past 12 months is the escalating geopolitical instability in the wider region, with Greek-Turkish tensions jeopardising gas supply from Turkey (one of Greece's key gas import corridors), showcasing the need for sufficient gas storage facilities to safeguard the security of supply and broadly expected to have a major impact on future government policy, including on diversification of power supplies.

On the electricity infrastructure front, the Independent Power Transmission Operator ("**IPTO**") is in the process of integrating the island of Crete with the Interconnected System. Until recently, electricity on Crete was provided by an autonomous electricity system, with power mainly generated by oil-fired plants (with a total capacity of 813 MW), together with substantial capacity provided by renewable sources (with a total capacity of 279 MW). Crete is expected to be fully integrated in two phases, comprising the Crete-Peloponnese interconnection, which has been electrified, successfully making this project the longest subsea alternative current connection in the world, and the connection between Crete and Attica, currently expected to be completed by the end of 2023, Ariadne Interconnection S.A., a special purpose vehicle ("**SPV**") established by IPTO, assigned with the implementation of the Athens-Crete interconnection project, has started construction of the electricity grid project. Outdated diesel-fuelled power stations operating in Crete need to be phased out in order to meet EU environmental standards. Electricity interconnections with the Dodecanese island complex and the North Aegean islands are planned for 2029 and 2031, respectively. These subsea interconnections will not only contribute to the reliability of the power supply and to the economic growth of the island regions but, most importantly, will help prevent the islands' environmental degradation and enable the injection of increased RES capacity from the islands into the national grid.

In addition to integrating the non-interconnected islands, in 2023, IPTO has made progress and is also expanding the number of cross-border international interconnections. IPTO is already interconnected with Albania, Bulgaria, Italy, North Macedonia and Turkey, and expects to complete a second interconnection with Bulgaria by 2023. This additional cross-border interconnection is expected to contribute to increased cross-border exchanges, improve the security of electricity exchanges between Greece and Bulgaria, and accommodate expected future renewable energy generation capacity in Northeast Greece.

Other significant market trends and developments include the ongoing interconnection of some of the non-interconnected islands (e.g. Cyclades) with the Interconnected System. In the non-interconnected islands, electricity has historically been generated autonomously or in complexes of adjacent islands. Integrating the non-interconnected islands should increase the reliability and security of electricity supply, reduce generation costs, enable grid decongestion and increase opportunities to exploit significant renewable energy capacity.

Energy infrastructure is also evolving at the EU level. Two energy axes that are expected to upgrade the country's role as an "energy channel" for Europe and an established exporter of green energy are to be constructed, with the involvement of DESFA and IPTO. These are the Green Aegean Interconnector, an electricity interconnector, which is planned to have its starting point in Greece and its ending point in Germany, and the Vertical Gas Corridor, both aimed at transferring green electricity and gas to the European north.

Over the past 12 months, Greece has continued to face growing grid congestion challenges, which, along with the green transition targets, create the need for drastic measures and significant investment in grid infrastructure. The legislation enacted in July 2022, as further amended in early 2023, intends to decrease grid congestion, including by adjusting the capacity margins in congested areas and releasing grid capacity from existing plants that cease operating. This new initiative also set the ground for IPTO to stop accepting new grid connection applications for specific periods of time in areas where the grid has limited space. The Government is closely monitoring the connectivity margins across the various regions of the country and aims to adjust the grid connection framework to facilitate renewable energy project development.

Developments in government policy/strategy/approach

Following the enactment of the "Clean Energy for all Europeans" package, in early 2020, the Greek Government issued a new NPEC, which formed the Government's current policy aimed at protecting the environment and dealing with climate change. The NPEC set the following key targets: (a) full decarbonisation by 2028, based on a detailed schedule introduced later on (this target has been temporarily suspended in light of the recent energy crisis); (b) power from RES to become the country's main energy source, reaching 65% of power production in 2030; and (c) a more ambitious greenhouse gas emissions cut target, aimed at reducing emissions by more than 42% compared to 1990 and by more than 56% compared to 2005. Based on the NPEC, energy efficiency incentives for the energy renovation of public buildings, industrial facilities and residences were set to be granted during 2020–2022. Furthermore, the NPEC envisaged investment of a value up to €43.8 billion in RES, natural gas and electricity transmission and distribution networks, as well as granting of financial incentives for the purchasing of electric vehicles ("**EVs**") and launching of energy-saving programmes by 2030.

Following the introduction of the Fit for 55 package, the Government is in the process of amending the existing NPEC with a view to increasing the targets for RES capacity for 2030 and 2040, primarily aimed at further reducing the country's dependence on Russian natural gas. The new NPEC is also expected to set more ambitious targets for cutting down the country's energy demand and achieving higher blending rates for hydrogen and renewable gases (e.g. biomethane) in the gas mix; at the same time, the NPEC introduces a step back in the development of photovoltaic ("**PV**") and offshore wind farms and an increase in the share of onshore wind in Greece's energy mix by 2030. Further, in relation to energy storage, which is considered essential for the stability of the electricity system, the relevant target is revised at 8.1 GW of storage units to be installed by 2030. Finally, the target related to natural gas remains unchanged compared to the previous NECP, i.e. a 50% reduction by 2030 compared to the share of gas in the Greek energy mix of 2021.

The first National Strategy for Green Hydrogen is expected to be announced by the end of 2023, setting targets for each sector as well as a financial support scheme to boost new investments in the sector.

Adoption of the recast Electricity Directive (EU) 2019/944, the recast Renewable Energy Directive (EU) 2018/2001, the revised Energy Efficiency Directive (EU) 2018/2002, the new Electricity Regulation 2019/943, the Energy Performance of Buildings Directive 2018/844, as well as the Regulation on governance of the energy union and climate action (Regulation 2018/1999), the Regulation on risk-preparedness in the electricity sector (Regulation 2019/941) and the Regulation on a European Union Agency for the Cooperation of Energy Regulators (Regulation 2019/942), is expected to gradually transform the internal energy market towards a sustainable, low-carbon and environmentally friendly economy.

A huge milestone in the Government's environmental and climate policy is the adoption of the first National Climate Law (please see the "*Developments in legislation or regulation*" section below), as part of its broader effort to create a carbon-free community by 2050. The Greek Government is determined to enhance the RES market, particularly by streamlining the licensing process and reducing bureaucracy, as well as by granting attractive tax incentives for upgrading the energy performance of buildings, aiming to accelerate the rate of building renovation towards more energy-efficient systems, and make new buildings "smarter".

With a view to boosting the establishment of hybrid renewable energy systems in locations that are not fitted with an electricity distribution system, such as the non-interconnected islands, the Government has developed a special legal framework to govern hybrid power, including specific pricing schemes. The creation of a hybrid power market, which is expected to entail the granting of favourable tariffs through competitive procedures, will aim at providing increased system efficiency as well as greater balance in energy supply, resolving the significant power outage issues on the Greek islands.

To this effect, the Government introduced a fully fledged regulatory framework to govern storage projects and hybrid projects with combined generation and storage (please see the "*Developments in legislation or regulation*" section below), and completed the first storage capacity auction in August 2023 for the financial support primarily of battery energy storage system capacity, granting operating and investment aid. Based on the Government's announcements, total storage capacity to be auctioned exceeds 700 MW, while technical and market rules for the participation of hybrid projects in the market are pending specification. The prospect of increasing the auctioned capacity for battery-based renewable energy projects is rooted in the role that these projects can play in curbing "green" generation curtailments, which have already begun to appear in the domestic system and are expected to increase in the following years. In addition, behind-the-meter battery plants are also a countermeasure to the local congestion problems that will occur.

Another critical development showcasing the Government's current energy policy and determination to achieve the decarbonisation targets was the enactment of a long-anticipated framework to regulate the development of offshore wind plants – a target of 2 GW capacity in operating floating offshore wind farms by 2030 has been set, with several major local energy players partnering with foreign companies with experience in the development of offshore plants in preparation for the implementation of the new framework (please see the "*Developments in legislation or regulation*" section below). By the end of 2023, the "map" of the zones in the Greek seas where offshore wind farms can be developed is expected to be formalised, paving the way for the first domestic investments to exploit the country's rich offshore wind potential. The National Program and the Strategic Environmental Impact Assessment ("**SEIA**") for the "map" zones is expected to be released for consultation by the end of 2023. The tenders for potential investors are set to take place during the first half of 2027, with the concessions of the offshore "plots" being finalised around a year later. Thus, from the first half of 2028, following completion of the tenders, qualifying investors will be prepared to kick-off construction of offshore wind farm projects.

In the same context, for the first time, Greece has introduced regulations for offshore solar plants in an effort to boost the relevant market and for additional solar capacity to be contributed to the country's energy mix (please see the "*Developments in legislation or regulation*" section below). As far as the RES projects are concerned, the Government has declared its commitment to promoting merchant power purchase agreements and direct wholesale market participation, as opposed to offtake agreements providing for operating aid, which has been the established practice since the creation of the renewables sector in Greece. As part of the operating state aid granted to RES producers, following a pilot tender carried out in 2016, and the state aid clearing of tariff framework, in 2018–2020, three broader rounds of technology-specific and joint (for PV and wind parks) capacity tenders were successfully conducted by RAE, comprising 14 separate competitive procedures in total.

The country's policy and strategy around available offtake solutions for renewables projects continues to evolve. During the period 2017–2021, 687 projects participated in auctions for the securing of state-regulated tariffs, with a total capacity of 1.28 GW (PV projects) and 1.34 GW (wind projects) being awarded feed-in premium ("**FiP**") contracts. These auctions resulted in the gradual lowering of the average reference tariffs. While the last competitive procedure under the previous framework took place in January 2021, following the expiration of the initial term of the RES state aid scheme, the Greek Government adopted a new tariff auctions support scheme, which has already been launched and will extend to 2025; in this context, RES projects with a maximum total capacity of *c*. 3.5 GW are expected to be awarded operating aid.

In order to achieve the transition from government-backed offtake agreements to private offtake arrangements, Greece is in the process of completing overhauls of its wholesale energy market. Initially, Law 4512/2018 paved the way for replacement of the mandatory pool model by a day-ahead market, an intra-day market, a balancing market (comprising the balancing capacity market, the balancing energy market and the imbalances settlement) and an energy derivatives market. From the contribution of the aforementioned branch to the new company, it followed that LAGIE is no longer the electricity market operator and the wholesale electricity market as a whole has now been transferred to the Hellenic Energy Exchange ("**HEnEx**"). In turn, LAGIE, comprising the remaining sectors, was renamed DAPEEP, assuming the role of operator of RES producers and guarantees of origin ("**GOs**").

Directive (EU) 2009/72, as part of the Third Energy Package, first laid the groundwork for the restructuring of the electricity market, aiming to establish access to the network for cross-border exchanges in electricity. This initial effort was further elaborated by subsequent Regulations (EU) 713/2009 and 714/2009, introducing the so-called "EU Target Model", laying down the major target of European electricity market integration.

A key component of the EU Target Model, as set out in Regulation 2015/1222 ("**CACM Regulation**"), is the concept of market coupling, which Greece is in the process of setting the ground for, in close cooperation with its neighbouring countries. This effort began with the establishment of a radically new wholesale market model, aiming to enhance competition and remove significant distortions in the electricity market (see above regarding the establishment of HEnEx). The Greek electricity market is gradually being coupled with Bulgaria and Italy, as set out in Article 15 (1) of the CACM Regulation in ACER Decision 6/07.11.2016, while GO market interconnections are also under way.

Both the day-ahead market (where electricity is traded for physical delivery within the subsequent 24 hours) and intra-day market (transactions for physical delivery of electricity within the same day in order to cover any failures to fulfil deliveries from orders that have been closed over the previous 24 hours through the next day's purchase) are operated in accordance with RAE Decision 1116/13.11.2018, as amended and currently in force. The Hellenic Capital Market Commission together with RAE are the responsible authorities for the supervision of the energy derivatives market. Therefore, under this new market model, traded products are either financially or physically settled. Apart from the energy derivatives market, market participants also have the option to conclude bilateral energy contracts (over-the-counter contracts), which shall be declared to a registration and nomination platform operated by HEnEx in order to be submitted as orders in the day-ahead market. As interconnections with neighbouring countries gradually come online, the day-ahead market should also enable market coupling and EU-wide clearing for wholesale electricity.

In order to specify the rules of operation of the wholesale energy markets under the EU Target Model in Greece, RAE issued Decisions 1008A/2020 and 1657/2020, setting a maximum percentage of transactions that may be conducted bilaterally through over-the-counter energy financial instruments with physical delivery. More specifically, according to Article 18, paragraph 6 of Law 4425/2016, in order to ensure efficient operation of the electricity markets, a maximum rate of transactions on energy financial instruments per portfolio may be determined. According to the abovementioned decisions, bilateral contracts were allowed at up to 20.0% for suppliers with retail market share exceeding a 4.0% threshold. This restriction took effect following commencement of day-ahead market operation, i.e. 1 November 2020, and was abolished on 31 December 2021.

In the investment field, the Government continues its privatisation programme albeit at a slower pace when compared to the previous five years.

A key potential investment initially expected to enhance security of supply in the Greek market and improve the management of natural gas supplier portfolios, particularly in light of the effort to minimise dependence on Russian gas, was the development and commercial exploitation of an underground natural gas storage ("**UGS**") facility in the South Kavala natural gas reservoir. The Hellenic Republic Asset Development Fund ("**HRADF**") launched an international tender for concession of the almost depleted South Kavala offshore natural gas field, with three international players expressing their interest in the first phase of the procedure in October 2020. The tender was repeatedly delayed mainly due to ongoing consultation regarding the facility's business pricing framework, and disagreement between RAE and DESFA with respect to additional investments required for the effective operation of the UGS facility, and officially came to an end in March 2023 following an absence of eligible bids.

At the natural gas utilities level, the past few years have been eventful for the restructuring of previously state-owned public gas corporation DEPA. More specifically, Law 4602/2019 provided for the split of the commercial and infrastructure activities of DEPA. Subsequently, based on Law 4643/2019, amending Law 4602/2019, DEPA was divided into three separate legal entities: "DEPA Infrastructure S.A.", comprising all the distribution gas activities of DEPA; "DEPA Commercial S.A.", to which all DEPA's gas-related activities (both wholesale and retail) are transferred; and "DEPA International S.A.", comprising all the international infrastructure projects in which DEPA participates. Under the same law, the sale of HRADF's total shares in DEPA Commercial S.A. and DEPA Infrastructure S.A. was proclaimed, excluding shares of DEPA International S.A. In July 2021, the international tender for the acquisition of 100% of the share capital of DEPA Infrastructure S.A. took place, resulting in a successful outcome and the selection of Italgas SpA group as the successful investor. Unlike with DEPA Infrastructure S.A., the international tender launched in February 2020 for the sale of a majority shareholding (65%) in DEPA Commercial S.A., with an option to acquire the total of its issued share capital, was suspended as of mid-2021, mainly due to significant litigation against the target company, with the latest statements by the Government indicating that no sale process will be initiated in the near future, as the Government has opted to retain its shareholding in the gas company in light of the energy instability.

In addition to the above developments, over the past two years, the Government has completed the successful sale of a 49% stake in the Hellenic Electricity Distribution Network Operator ("**HEDNO**") to an international fund, the transfer to HEDNO of the distribution network, which previously belonged to PPC (in the context of HEDNO's part-privatisation), the launch of an international tender for the sale of a 20% stake in Ariadne Interconnection S.A., and the launch of construction of the EuroAsia Interconnector, a proposed high-voltage direct current interconnector between the Greek, Cypriot, and Israeli power grids via the world's longest submarine power cable. Based on Articles 106–108 of Law 4821/2021, as of 1 August 2021, ownership of the Crete HV System passed automatically from PPC to IPTO, while management of the system passed from HEDNO to IPTO on 1 October 2021.

Another item on the Government's agenda is the sale of a further stake in IPTO, an entity vested with the ownership and operation of the national power grid. IPTO, originally established by virtue of Law 4001/2011 as a 100% subsidiary of PPC, was restructured in 2017 based on the Ownership Unbundling Model, through the sale of 24% to a strategic investor and the transfer of 25% to a state-owned SPV, with the Greek State indirectly retaining 51% of its shares. The further privatisation of IPTO is expected to secure much-needed funds for the expansion and upgrading of the power grid, facilitating the connectivity of new RES units and ultimately serving the carbon neutrality targets.

Developments in legislation or regulation

By way of background, Law 4001/2011, transposing Directives 2009/72/EU and 2009/73/EU, remains the main piece of legislation currently governing the operation of energy markets in the electricity and natural gas sectors in Greece, including the production, supply, purchase, transportation and distribution of natural gas and electricity. Its primary objective was the creation of a single internal energy market, in line with EU secondary legislation; therefore, its provisions focus on the separation of transmission and distribution activities from generation and supply activities in the electricity and gas sectors. To this end, the same law established a certification process for transmission system operators, and measures for the effective unbundling of the regulated transmission and distribution activities from the competitive production and supply activities.

As anticipated above, until recently, by virtue of Law 4001/2011, the Greek wholesale market model was organised on the basis of a regulated compulsory offer of electricity to a day-ahead market, leading to the centrally organised sale of electricity at a uniform price (System Marginal Price), which reflected the offer of the most expensive unit dispatched. Participants to the mandatory pool were, on the one hand, producers and importers of electricity and, on the other hand, suppliers and exporters of electricity. Imbalances (i.e. deviations from day-ahead schedules) were settled through a distinct mechanism, but there was no balancing market. Clearing of the day-ahead market was performed by market operator LAGIE, while IPTO was responsible for conducting the real-time dispatch, clearing imbalances as well as settling payments for ancillary services and several other charges.

Law 4512/2018, in implementation of the CACM Regulation, introduced the new market model to be regulated by HEnEx and comprised the electricity market, the energy financial market, the natural gas market and the environment market. As mentioned above, the electricity market is divided into a day-ahead market, an intra-day market, a balancing market and an energy derivatives market. The balancing market is operated by IPTO, which is responsible for ensuring compliance with Regulation 714/2009 and the Regulation on wholesale energy markets integrity and transparency. A landmark development expected to completely transform the Greek energy market was the entry into full operation of HEnEx in 2021. The new entity was founded through a spin-off from the electricity market branch of electricity market operator LAGIE by virtue of Law 4512/2018. The establishment and operation of HEnEx, which is owned by state-controlled DAPEEP, the Athens Exchange Group, IPTO, the European Bank for Reconstruction and Development, the Cyprus Stock Exchange and DESFA, are mainly governed by Law 4512/2018. Following the formation of HEnEx, "EnEx Clear", a 100% subsidiary of HEnEx, was established as the market clearing house.

The Greek RES market is primarily regulated by Law 3468/2006, which, among others, introduced the first state aid scheme based on a guaranteed feed-in tariff ("**FiT**") system (operating support based on a fixed compensation price), where producers received standard remuneration amounts and, consequently, minimised exposure to market risk. Law 3468/2006 differentiated between various categories of RES producers, and the amount of remuneration varied depending on whether the plants were located in mainland Greece or on the islands, i.e. whether they were connected to the mainland grid.

Following a deadlock in the previously implemented support schemes and after a period of stagnation between 2013 and 2018, the Greece RES market has been booming for the past five years, particularly as a result of a state aid scheme introduced by Law 4414/2016, aiming to enhance RES investment and align the Greek energy market with EU targets. Under this RES state aid programme, currently set to run until 2025, qualifying RES projects may be granted 20-year operating aid agreements in the form of FiP contracts, i.e. contracts-for-difference between the market price of electricity and a fixed reference price, which is determined through competitive procedures conducted by RAE, all in replacement of the previous unsuccessful FiT system.

Small-scale as well as demonstration projects are exempted from this FiP scheme, in which case standard FiT contracts are entered into with DAPEEP. Based on Law 4643/2019 and in compliance with Regulation 2019/943, as of 1 January 2020, RES plants with a capacity equal to or higher than 400 kW are only eligible for FiP contracts awarded through bidding procedures, while at the same time undertaking balancing obligations in the HEnEx market (this threshold is expected to be lowered to 200 kW in 2026 in compliance with EU legislation).

As of 1 November 2019, RES projects having already entered into FiP contracts became participants of the day-ahead market, either directly or through a RES aggregator ("**FOSE**"), and are now operating subject to clearance and settlement procedures. RES projects participating in the day-ahead market undertake commitments for the accurate prediction of the declared injected quantity of power, following implementation of the intra-day and balancing markets (having entered into FiP contracts or the FOSE through which the producers are represented in the electricity wholesale market), and have undertaken standard balancing obligations.

Law 4685/2020 attempted the fundamental reform of the energy licensing and the regulatory regime, dealing with administrative inefficiencies of the previously applicable rules and providing a safe legal environment for prospective investors, particularly in the RES sector. The main novelties introduced by Law 4685/2020, which focused on the overhaul of the RES licensing framework, include the following: (a) the RES production licence was replaced by a certificate issued digitally through a fast-track procedure; (b) the duration of environmental licences was extended from 10 to 15 years, while deadlines for the issuance of environmental licences were largely shortened; (c) various restrictions for the use of land were wholly or partially lifted; and (d) new deadlines for several milestones of the licensing procedure were set.

Further to the first-phase licensing simplification effected by Law 4685/2020, the new Law 4951/2022 was enacted, overhauling the RES licensing framework and further reforming the Greek energy market. More specifically, based on Law 4951/2022: (a) numerous amendments were introduced, aimed at reducing the average licensing time for RES projects from five years to 14 months; (b) measures were adopted for the management of available grid capacity both at the level of IPTO's power transmission system and HEDNO's distribution network; (c) a special grid connection priority framework was introduced and further implemented through Ministerial Decision 4333/12.08.2022 of the Ministry of Environment and Energy in an effort to transparently resolve the grid congestion bottleneck; (d) a completely new framework regulating energy storage was introduced, opening the door to investment in standalone storage as well as hybrid projects; (e) a set of provisions laid the groundwork for the development of offshore solar plants, initially launching a first bundle of up to 10 pilot PV projects; and (f) the legal framework governing GOs was substantially amended, streamlining the relevant trading market.

As part of the Government's effort to contain the growing congestion of RES licences and pending applications and, effectively, to limit the number of future producers by testing their financial capacity, Law 4819/2021 imposed certain significant obligations on the developers of early-stage RES and CHP projects. Following the enactment of the new law, in order for RAE to issue a Producer's Certificate or a Special Project Certificate, applicants are now under the obligation to submit a Letter of Guarantee equal to €35,000/MW to RAE. Additional guarantees are required from the RES developers in the context of the grid connection priority framework (Ministerial Decision 4333/12.08.2022, as amended and in force).

Another central development was the enactment of Law 4710/2020 in July 2020, introducing for the first time a fully fledged legal framework to govern the Greek e-mobility market. This new law enabled the installation of publicly accessible EV charging stations in existing fuel stations, shopping centres, supermarkets, parking lots, as well as in public buildings and along motorways or highways. Further, Law 4710/2020 provided for the establishment of EV charging operators, expected to primarily develop their own recharging stations at new, designated locations. The various incentives to be offered under Law 4710/2020 and its implementing acts, including granting of subsidies to private users (indicatively, reduction of VAT for the purchase of EVs), tax benefits, as well as the introduction of traffic privileges for the use of EVs, are expected to be instrumental in encouraging drivers to use EVs.

On the route to adopting the Gas Target Model, as well as to achieving DESFA's strategic objective of creating a regional gas hub in Greece, a significant development in the natural gas field was the launch of the HEnEx Natural Gas Trading Platform in 2022, allowing for the first time the conduct of anonymous transactions for natural gas in the national system. The platform is expected to serve as a key tool to the future integration of renewable gases and other innovative products into the Greek wholesale market. Previously, a virtual trading point started operating at the NNGTS in 2018. With the activation of the virtual trading point, natural gas traders not involved in physical trading were offered for the first time the possibility to operate in the Greek market, since it became possible to carry out transactions irrespective of whether they had contracted capacity at entry/exit points.

In May 2022, the first-ever National Climate Law (Law 4936/2022) was enacted, setting forth a roadmap for the gradual reduction of greenhouse gas emissions and carbon neutrality by 2050, in compliance with the relevant EU target. This law: (a) provided for additional targets to limit greenhouse emissions by at least 55% by 2030 and 80% by 2040, as compared to 1990; (b) set the goal of cutting dependency on fossil fuels by 2028, subject to security of supply concerns; (c) imposed several obligations on the transition to zero-emission vehicles, setting specific quotas and deadlines; and (d) mandated certain large corporations (financial institutions, telecom providers, electricity suppliers, water and waste utilities, logistics companies and retail businesses) employing over 500 employees to comply with stricter environmental standards and annually report their carbon footprint status.

Finally, a milestone legislative development was the introduction in July 2022 of a legal framework for the development of offshore wind plants in Law 4964/2022 under the title "*Simplification of environmental licensing, establishment of a framework for the development of offshore wind farms, addressing the energy crisis, forestry protection and other provisions*". Based on this law, state-owned Hellenic Hydrocarbon Resources Management ("**HHRM**") was transformed into the Hellenic Hydrocarbons and Energy Resources Management Company ("**HEREMA**") and was vested with the responsibility of coordinating and handling the overall process of developing offshore wind farms.

Law 4513/2018 had initially set the legal framework for the establishment of energy communities, aiming to promote social economy, solidarity, innovation and sustainability in energy, as well as to increase energy efficiency in the final consumption of local communities. By way of several legislative amendments following the introduction of energy communities into the Greek market, various incentives have been granted to projects developed by such communities, including privileged grid connection potential, limited financial obligations (guarantees submitted to the competent authorities) and tariff-related benefits. Recently, Law 5037/2023 introduced significant changes in respect of the current energy communities' framework, gradually abolishing the traditional scheme operated under Law 4513/2018. Instead, two new similar types of legal entities have been introduced: Renewable Energy Communities; and Citizen Energy Communities. The aim of the new legislation is to relaunch and streamline the concept of energy communities, by limiting their formulation to purely commercial entities and reserving regulated tariffs and licensing incentives for Citizen Energy Communities, operating to the benefit of local communities.

The field of self-consumption has not been an exemption in terms of critical legal developments. While self-production was initially introduced into the Greek legal system by Law 3468/2006 and further regulated by Law 4144/2016, as well as by relevant secondary legislation, the provisions of recent Law 5037/2023 effectively transformed the relevant legal framework. Based on the new amendments, the traditional form of net-metering is limited to small-scale plants, while virtual net-metering is boosted. Most importantly, the concept of net-billing was introduced for the first time in Greece, both in physical and virtual form, while the new law enables the development of collective self-consumption schemes in close interaction with Citizen Energy Communities.

Judicial decisions, court judgments, results of public enquiries

Following the introduction of price adjustment clauses by the majority of the country's power suppliers in August 2021, energy consumers suffered significant increases in their electricity bills and massive reactions against retailers arose, mainly due to alleged lack of transparency in the determination of the final payable amounts. In particular, several complaints by customers were submitted to power retailers, while a class action was filed against PPC by customers claiming that they are unable to calculate and monitor the final cost of their electricity bills, despite PPC claiming that the price adjustment derives from a transparent mathematical formula. Following the first court hearing for the *Consumers' Association – Quality of Life vs PPC* class action on 6 July, PPC was prohibited from cutting off power to vulnerable households failing to pay their bills (containing price adjustment clauses) pending a final verdict. Further, lawsuits by customer unions and other professional unions were filed, requesting the annulment of the price adjustment clauses. In response to these vehement reactions, the Government temporarily suspended price adjustment clauses, effective from August 2022 to the end of 2023 (Article 138 of Law 4951/2022) and facilitated customers' right to frequently switch power suppliers, depending on the competitive prices offered on the market.

On a slightly relevant note, a judgment of the Council of State (the supreme administrative court of Greece) issued in 2020 was critical in the formulation of the legal framework governing the Greek retail electricity market and more specifically, the change of power suppliers by customers. By way of this ruling, the below provisions of Ministerial Decision 177367/2016 were annulled: (a) a provision based on which a customer willing to shift to another power supplier could only terminate the existing power supply contract provided that there are no outstanding debts to the existing supplier; and (b) the provision that a debt settlement plan has been agreed upon with the existing power supplier. The same Ministerial Decision provided that if the indebted customer failed to make the scheduled settlement payments on the relevant due dates, the previous supplier could request HEDNO to cut off such customer's power supply, even though a new power supply contract with the new supplier was in place. These provisions were annulled by the Council of State on the grounds that they impose extremely onerous and disproportionate restrictions on customers.

Endnotes

1. Residual Energy Mix 2022 – ΕΝΕΡΓΕΙΑΚΟ-ΜΕΙΓΜΑ-2022.pdf (https://dapeep.gr).
2. "Greece and the European Union 4 years after the decision to phase out lignite", https://thegreentank.gr/en/2023/09/22/greece-and-the-european-union-4-years-after-the-decision-to-phase-out-lignite
3. Joint Ministerial Decision YPEN/DHE/70248/2434/05.07.2022 on "Determination of methodology and mathematical formula", for the calculation of the administratively determined unit price for each category of production units and for RES portfolios in the context of the operation of the Temporary Mechanism for the Partial Return of the Day-Ahead Market Revenue (Electricity) in accordance with Article 12A of Law 4425/2016.

Yannis Seiradakis
Tel: +30 210 339 2950 / Email: yseiradakis@bernitsaslaw.com

Yannis Seiradakis has a wide-ranging transactional practice that encompasses significant experience in acting in complex privatisations, public and private projects and mergers and acquisitions. He has particular expertise in the energy, infrastructure, utilities and transport sectors.

Yannis' vast experience in privatisations reaches back to his time as Special Secretary for Privatisations at the Ministry of Finance, in which capacity he managed the sale of numerous state-owned companies, notably public utilities. He has been involved in high-profile privatisations of grid operators, motorways, ports, airports and railways. Yannis is an expert in energy law, advising on the structuring, development, financing and implementation of transactions and projects in the conventional and renewable energy sectors. He advises extensively on legislative risk and compliance and counts leading energy companies, international investors, financiers and Government bodies among his clients.

Yannis advises both privately and state-owned entities and consortiums on project financings and public-private partnerships, with a specialisation in documenting and negotiating concession contracts. He also advises on the regulatory framework for the assignment of public contracts by way of tenders and for developing projects and public-private partnerships. Furthermore, Yannis advises public and private companies, investors and financial advisors in mergers, acquisitions, restructurings and divestments of primarily distressed assets.

Eleni Stazilova
Tel: +30 210 339 2950 / Email: estazilova@bernitsaslaw.com

Eleni Stazilova is a senior associate at Bernitsas Law. She advises on project finance and energy-related transactions, public procurement and public-private partnerships.

Eleni has experience in drafting and negotiating commercial and finance agreements and participating in due diligence reviews. She also advises on the legal and regulatory framework governing tender procedures, acquisition and development projects in the conventional and renewable energy sectors, and on licensing and permit requirements for all types of energy projects.

Eleni represents clients in filing tender bids and legal recourses, petitions and applications arising from their participation in tenders and other public procurement procedures. Prior to joining the firm, Eleni worked as corporate counsel in the architectural and construction sectors in Greece and abroad.

Bernitsas Law
5, Lykavittou Street, GR-10672 Athens, Greece
Tel: +30 210 339 2950 / +30 210 361 5395 / URL: www.bernitsaslaw.com

India

Hemant Sahai, Molshree Bhatnagar & Parichita Chowdhury
HSA Advocates

Changes in the energy situation in the last 12 months that are likely to have an impact on future direction or policy

The energy demand in India has been rapidly increasing, with a projected 25% growth by 2030. There have been several developments over the past year that are geared towards helping the country meet this demand, while aiming for energy self-sufficiency by 2047 and net-zero emissions by 2070.

Creating a hydrogen economy

Green hydrogen (hydrogen produced from renewable energy) can potentially reduce the country's energy import burden and transform India's industries (petroleum, refining, steel) towards low-carbon self-reliance. As part of the National Hydrogen Mission (approved by the Union Cabinet on 4 January 2023 with an outlay of Rs 19,744 crore with the aim of making India a global hub of green hydrogen production, utilisation and export), the Ministry of Petroleum and Natural Gas (MOPNG) is undertaking several hydrogen initiatives and demonstration projects ultimately designed to achieve a greater use of hydrogen within India's energy sector. Some of the ongoing projects are as under:

- Multiple pathways project: This is a first-of-its-kind project designed to investigate and address all aspects of the value chain for hydrogen-based mobility. The demonstration for this includes 15 hydrogen fuel cell buses to conduct a 20,000km field trial and four demonstration units of hydrogen production that will deliver 40 tonnes per day, where three of these units will be based on renewable sources such as biomass gasification, reforming compressed bio methanol gas and solar photovoltaic (PV)-based electrolysis.
- CNG blending initiative: Under this project, hydrogen is blended with compressed natural gas (CNG) to the extent of 18% for use as transportation fuel. As a trial run, about 50 buses in the national capital of Delhi are running on blended hydrogen in CNG.
- Other hydrogen projects: The MOPNG is planning several pilot/demonstration projects on renewable hydrogen, such as projects for solar hydrogen refuelling stations, green hydrogen plants for replacement of conventional hydrogen in refineries, blending hydrogen with CNG at retail outlets, and pipeline injection of renewable hydrogen in the city gas distribution network.

In October 2023, the Ministry of New and Renewable Energy, Government of India (MNRE) issued the R&D Roadmap for Green Hydrogen Ecosystem in India. The Roadmap recommends research and development actions for each part of the green hydrogen value chain, and is expected to provide guidance for developing a vibrant ecosystem required to commercialise green hydrogen production and utilisation, thereby contributing to India's ambitious climate and energy goals.

The Government of India has also introduced the Hydrogen Purchase Obligations under which certain industries, such as refining and fertiliser, will be required to use a certain proportion of green hydrogen out of their overall consumption of fossil fuel-based grey hydrogen. The Government has also envisaged reducing the price of green hydrogen, which is around Rs 300 per kg at present. Industries across the globe are contemplating reducing the price of green hydrogen to USD 1 per kg (about Rs 82).

Extending certain benefits to renewable power projects

The Ministry of Power (MOP), *vide* its Order dated 9 June 2023, has amended its previous Order dated 29 May 2023 and provided the benefit of extended timelines for projects having a scheduled date of commissioning on or before 30 June 2025 and being eligible for a waiver of inter-state transmission charges. It has also been provisioned that the period of long-term access for such projects shall also be extended accordingly, and it will be deemed that the period of the inter-state transmission system (ISTS) waiver is extended by said period. However, such benefit shall only be granted on two occasions and only for an extension of six months on each occasion. HSA has advised several developers on how the aforesaid benefit ought to be taken into account while drafting future agreements for sale of power.

Looking beyond domestic coal

India's increasing power demand cannot be met by reliance on domestic coal alone. In an attempt to alleviate problems stemming from the shortage of domestic coal, MOP, Government of India, issued directions on 5 May 2022 under Section 11 of the Electricity Act, 2003 ordering all Imported Coal-Based Plants to operate and generate power at full capacity and provided an interim tariff, being subject to final determination by the appropriate regulatory commission, as the tariff under power purchase agreements (PPAs) was not viable and such power could be procured by state distribution licensees at this interim tariff irrespective of whether such power was supplied under the PPA(s). The final determination of the tariff by the regulatory commission, the Central Electricity Regulatory Commission (CERC) in this case, had to be based on complex factors indicative of the actual cost of generation and supply incurred by such Imported Coal-Based Plants. Importantly, the matter presented the unique issue of supply of power contracted under the PPA, which entailed that the regulatory commission could only place limited reliance on previous jurisprudence on the issue as in no other case had directions under Section 11 of the Electricity Act, 2003 categorically deemed the tariff under the PPA as unworkable. The directions dated 5 May 2022 ended on 31 December 2022; however, in continuation of the same, such directions were again issued on 20 February 2023 with the same objective of alleviating the burden on domestic coal through operationalisation of the Imported Coal-Based Plants at full capacity by providing an interim tariff from 16 March 2023 to 31 October 2023.

In this regard, HSA advised Tata Power in respect of its 3805 MW capacity Mundra Project on the entire range of regulatory and commercial issues arising from the imposition of Section 11 directions issued by MOP in 2022 and 2023. Crucially, HSA has obtained a landmark order from CERC espousing the principles/methodology for computation of the cost-reflective tariff, taking into consideration the complex factors in compensating Tata Power for the actual costs incurred by it. Such consequential tariff is to be recovered from states to which Tata Power is supplying power under this regime. The principles stipulated by the regulatory commission for determination of such consequential tariff are bound to be instructive to the industry as a whole.

Energy storage systems

Renewable energy sources are becoming the standard option for new power plants, especially in developing countries, because of the ongoing drop in cost. Concerns about how renewables can completely replace fossil fuels for base-load power production have been raised due to the intermittent nature of energy. However, since the price of lithium-ion batteries has decreased over the past five years, the deployment of energy storage solutions has begun in earnest. As they approach cost parity, governments and private organisations are pushing to install large-scale manufacturing and supply plants for battery production. Reduced lithium battery costs also promote the use of electric vehicles, raising demand for renewable energy sources to power charging stations. Thus, using more fossil fuel-based electricity to power electric car charging accomplishes little to further the objective of achieving net-zero emissions.

HSA is advising diverse promoters on structuring hybrid green projects together with storage options on a captive consumer basis. Furthermore, HSA works with all the major domestic and international promoters and project developers engaged in the renewable energy space in India, and is involved in over 80% of renewable energy projects in regulatory, finance, development, corporate, M&A, land aggregation, etc.

Solar PV module production

Installation of solar PV has been a major contribution to India's National Solar Mission (NSM) target and, consequently, investment in the solar sector has risen manifold since 2020, as per the REN21 Renewables 2020 Global Status Report. However, the supply chain of solar PV has been massively dependent on the import of overseas components (modules, cells, and wafers) and technology. To help the domestic manufacturer become self-reliant, the Government of India is designing necessary policies, such as production-linked incentive (PLI) schemes to boost indigenous production and increasing tariffs on imports. This has created domestic competition amongst the players and brought motivation to increase production and develop deciduous technology. HSA has assisted NITI Aayog (the policy think tank of the Government of India) in drafting PLI policy in relation to the subsidies for, *inter alia*, battery manufacturing plants, electric vehicles, etc.

Developments in government policy/strategy/approach

REOA Rules

MOP notified the Electricity (Promoting Renewable Energy Through Green Energy Open Access) Rules, 2022 (REOA Rules) on 6 June 2022 in order to further accelerate India's ambitious renewable energy programmes, with the objective of ensuring access to affordable, reliable, sustainable and green energy for all. A reduction in the open-access transaction limit from 1 MW to 100 kW and appropriate provisions for a cross-subsidy surcharge, additional surcharge, and standby charge will incentivise consumers to obtain green power at reasonable rates. Further, since the Rules also address other issues that have hindered the growth of open access, consumers can now access renewable energy power more easily.

On 13 May 2023, MOP issued a clarification and direction in pursuance of the REOA Rules since, in a number of states, the green tariffs being determined under the REOA Rules were much higher than the average power purchase cost of renewable energy by the distribution companies. MOP thus clarified that in no case should the green tariff be higher than Average Power Purchase Cost of RE + Surcharge @ 20% of Average Cost of Supply + (say) a reasonable margin of 25 paisa. Further, the State Electricity Regulatory Commissions have been directed to align their regulations with the REOA Rules in terms of the Electricity Act, 2003.

Guidelines for energy storage systems

MOP has notified guidelines for the procurement and utilisation of battery energy storage systems (BESS) as part of generation, transmission and distribution assets, along with ancillary services. The guidelines have been issued in order to, *inter alia*, facilitate procurement of BESS, as part of individual renewable energy power projects or separately, for addressing the variability/firming power supply/increasing energy output/extending the time of supply from an individual renewable energy project or a portfolio of renewable energy projects, and/or to provide ancillary, grid support and flexibility services for the grid.

As per the Central Electricity Authority, the energy storage system (ESS) capacity required to integrate the expected growth in renewable energy capacity is estimated to be 16 GW by 2026–27 as significant growth is anticipated in the subsequent years. In pursuance of the same, MOP also notified the National Framework for ESS in August 2023 with the key objective of ensuring a constant supply of renewable energy (Round-the-Clock Renewable Energy), reduction of emissions and lowering of costs by incentivising ESS deployment. The framework introduces various policy measures and incentives, including energy storage obligations, waiver of ISTS charges for ESS use, guidelines for procurement of BESS, and inclusion of ESS in the Harmonized Master List for Infrastructure. It aims to provide a unified resource for stakeholders to understand the Government's vision for energy storage and its pivotal role in India's energy transition.

Renewable Purchase and Energy Storage Obligations

MOP, *vide* its Order dated 22 July 2022, notified the Renewable Purchase Obligation (RPO) and Energy Storage Obligation trajectory until financial year 2029–30, whereby a long-term growth trajectory has been set out. The Order was issued in pursuance of paragraph 6.4(1) of the National Tariff Policy, 2016, which stipulates that MOP, in consultation with MNRE, will prescribe such long-term trajectory. Notably, on 8 March 2019, the Government of India recognised Large Hydro Projects (LHPs), including Pumped Storage Projects (PSPs), over 25 MW as part of renewable energy. Energy from all LHPs commissioned after 8 March 2019 will be considered part of the RPO through a separate Hydro Power Purchase Obligation (HPO).

Regional Load Despatch Centres

On 28 September 2022, MOP issued a letter to all Regional Load Despatch Centres (RLDCs) to give directions under Section 37 of the Electricity Act, 2003 for scheduling of power under the renewable energy bundling scheme dated 12 April 2022, and clarified that renewable energy capacity can be set up anywhere and dispatched to any generating station or its beneficiaries. There is no requirement of an additional contract/agreement for scheduling of power. The power generated from the generating station may be scheduled to procurers under a PPA or sold in exchange. RLDCs are directed to give effect to the provisions of Clause 6.4 of the scheme dated 12 April 2022 and schedule power under the renewable energy bundling schemes.

The Electricity (Amendment) Bill, 2022

The Electricity (Amendment) Bill, 2022 has been introduced by the Government of India to, *inter alia*, create mandatory provisions for payment security mechanisms to be provided by the licensee, stating that no electricity shall be scheduled or dispatched by a National Load Despatch Centre (NLDC), SLDC or RLDC unless adequate security of payment has been made. Further, a cross-subsidy balancing fund is to be created by the State Government in case of issuance of a licence to more than one distribution licensee in an area of supply, and any surplus in the fund shall be utilised to make good deficits in cross-subsidy in the same area or other area of supply. Section 14 of the Electricity Act, 2003 has been amended, wherein the Appropriate Commission is given power to grant a licence to a distribution company as per the criteria that may be prescribed by the Central Government. An amendment to Section 62(1)(d) gives the power to the Appropriate Commission to fix a minimum and maximum tariff ceiling as against only a maximum ceiling of tariff, which was provided in the Principal Act, in case of parallel licensing given to distribution companies for the same area of supply. A provision has also been introduced that prevents the tariff from being amended in excess of four times during one year as per the Tariff Policy.

The amendment to Section 79(1)(f) reads as follows, wherein, *inter alia*, the Arbitration Clause has been removed: '(*f*) to adjudicate upon the disputes including those relating to *performance of obligations under a contract related to sale, purchase* or transmission of electricity, involving generating companies or licensees in regard to matters connected with clauses (*a*) to (*d*); (fa) *to adjudicate upon the disputes involving the National Load Despatch Centre or the Regional Load Despatch Centre* in regard to matters connected with sections 26, 28 and 29.' Similar provision is given for the amendment under Section 86(1)(f) for State Commission(s), wherein: 'Provided that in case of *reneging of Power Purchase Agreement by a generating company or a licensee, the dispute shall be adjudicated along with appropriate compensation to the affected party, within ninety days from the date of submission of petition* to the Appropriate Commission.' Further, powers of Section 94 of the Electricity Act, 2003 are now wider. The amendment provides that the Appropriate Commission shall have the powers of a civil court, and any order made by the Appropriate Commission shall be executable as a decree of a civil court.

HSA, under a World Bank assignment, assisted MOP in the drafting of the proposed revised provisions specifically in the context of privatisation of distribution companies, franchising in distribution, etc. The Bill is under consideration before Parliament.

Grid Security Charge

CERC issued a Staff Paper, inviting comments/suggestions from stakeholders, on the Grid Security Charge in September 2023. India has been witnessing a huge surge in demand over the period. The peak demand recorded a high of 241 GW on 1 September 2023. The growth of around 23% in peak demand met in August 2023 is unprecedented. India has resolved to ensure uninterrupted power supply to consumers and for this, a number of initiatives have been taken by the Government and Regulators. In this context, references have been received by CERC from the NLDC highlighting the shortage of adequate reserves to meet the contingency. The NLDC has also suggested some measures to ensure advanced procurement of reserves and to optimally utilise the existing gas-based generation to meet the requirements of grid security and reliability. The Staff Paper issued by CERC discusses such issues and various measures for ensuring the adequacy of reserves and, in turn, the reliability of grid operation.

Draft regulations for open access in Andhra Pradesh

Notably, on 30 September 2023, the Andhra Pradesh Electricity Regulatory Commission issued the Draft of the Andhra Pradesh Electricity Regulatory Commission (Green Energy Open Access, Charges, and Banking) Regulations, 2023 (Draft Regulations). Some key aspects of the Draft Regulations that are proposed to be implemented for granting open access for electricity generated within the State of Andhra Pradesh are as under:

- The Draft Regulations will apply to intra-state entities that use the intra-state transmission/distribution systems of licensed entities, including those incidentals to inter-state transmission.

- Entities with outstanding dues, involved in unauthorised electricity use or theft, or declared insolvent or bankrupt will not be eligible for open access.
- Long-term (five years or more), medium-term (more than one year but less than five years), and short-term (less than one year) green energy open-access consumers will be categorised based on their usage duration.
- Short-term consumers will be able to reapply for access upon expiration, subject to availability, with priority based on the application submission date.
- Green energy open-access consumers have priority over fossil fuel-based consumers in terms of connectivity and general access.
- The Andhra Pradesh State Load Despatch Centre (SLDC) and state transport undertaking (STU) will be acting as nodal agencies for granting short-term, medium-term, and long-term green energy open access.
- Various charges, including transmission, wheeling, cross-subsidy surcharge, standby charges, SLDC fees, scheduling and deviation settlement charges, and reactive energy charges will apply. Further, the processing fees will vary for different access durations.
- The Draft Regulations also allow energy banking for wind, solar, and mini hydropower generators with specific conditions.
- Curtailment priorities are established based on access duration and on a first-come, first-served basis during system constraints.
- Open-access applications will not be denied without a chance for applicants to be heard.
- Disputes and complaints are to be resolved by the nodal agency or Consumer Grievances Redressal Forum.
- MOP amended the Electricity Rules, 2023 by way of amendments dated 30 June 2023 and 1 September 2023. By way of the Amendment Rules, Rule 3(a)(i) of the Electricity Rules had been previously amended to provide that where a captive generating plant is set up by an affiliate company, at least 51% of the ownership of such affiliate company should be held by the captive user. However, by way of the amendment notified on 1 September 2023, said provision has been deleted by MOP.

<u>Regulating the domestic power market</u>

CERC issued another Staff Paper, inviting comments/suggestions from stakeholders, on Market Coupling in August 2023. Furthermore, the Power Market Regulations provide an enabling framework for the development of the power market. CERC notified the CERC (Power Market) Regulations, 2010 on 21 January 2010. Thereafter, in view of the developments in the power sector, including growth in overall power generation, growth in demand, increase in the volume of electricity transacted on the power exchanges, etc., CERC notified the CERC (Power Market) Regulations, 2021 (PMR 2021) on 15 February 2021 by repealing the earlier regulations. The main objective of these regulations is to help create a comprehensive market structure and enable the transaction, execution, and contracting of various types of products in the power market. At present, there are more than 50 inter-state trading licensees and three power exchanges, namely Indian Energy Exchange Ltd. (IEX), Power Exchange of India Ltd. (PXIL) and Hindustan Power Exchange Ltd. (HPX), operating under the framework of PMR 2021. Various contracts are available for trading on these exchanges to meet the short-term needs of market participants.

The idea of a multi-exchange model in the power sector was originally conceived with a view to encouraging competition amongst the exchanges and catering to the growing and varying requirements of market participants. A voluntary approach has been followed for participation in various contracts in the power exchanges. Over the years, the volume of transactions in the power exchanges has increased manifold, and similarly, the number of products and market segments has expanded in all the power exchanges. Recently, the cross-border trade of electricity has also commenced in the Day-Ahead Market (DAM) of IEX. Though the transactions through power exchanges constitute only about 7% of the total electricity generation, the volume transacted and the number of participants registered with the power exchanges have grown significantly. The issues concerning multi-exchange models have been discussed in this Staff Paper.

<u>Recovery of outstanding dues</u>

MOP notified the Electricity (Late Payment Surcharge and Related Matters) Rules, 2022 to bolster the provisions to recover outstanding dues from distribution companies. The Rules will be applicable to outstanding dues of generating companies, inter-state transmission licensees and electricity trading licensees.

<u>ISTS</u>

Furthermore, CERC has notified the CERC (Connectivity and General Network Access to the Inter-State Transmission System) Regulations, 2022, which provide a regulatory framework to facilitate non-discriminatory open access to licensees, generating companies and consumers for use of the ISTS through general network access and to consolidate regulation on the subject.

<u>CIL Rules</u>

On 21 October 2022, MOP issued the Electricity (Timely Recovery of Costs due to Change in Law) Rules, 2021 (CIL Rules), whereby it laid down the mechanism for generation and transmission project developers to seek relief on account of Change in Law events. As per MOP, the objective behind promulgation of the CIL Rules is to ensure timely recovery of compensation (due owing to Change in Law events), as investments in the electricity sector depend heavily on the timely flow of payments. As per the Rules, the affected party must be compensated so as to bring him to the same economic position as if a Change in Law event never occurred.

On 21 February 2022, MOP issued a clarification to the CIL Rules to address concerns raised by stakeholders that CERC has disposed of certain petitions filed by transmission licensees wherein CERC directed the developer(s) and other parties, i.e., the respondents, to settle the Change in Law claims amongst themselves and approach the CIL Rules. By way of its clarification, MOP stated clearly that the CIL Rules apply prospectively only and cannot be made applicable to developers who were affected by a Change in Law event prior to the promulgation of the CIL Rules.

<u>Guidelines for short-term procurement of power</u>

On 21 February 2022, MOP notified an amendment to the guidelines for short-term (i.e., for a period between one day and one year) procurement of power by distribution licensees through tariff-based bidding processes dated 30 March 2016. In the present amendment, the issue of the sale of power by generators in the market without the consent of the procurer has been addressed.

<u>Renewable Energy Certificates</u>

CERC has also notified the CERC (Terms and Conditions for Renewable Energy Certificates for Renewable Energy Generation) Regulations, 2022 (REC Regulations). By way of the REC Regulations, an NLDC has been designated as the nodal agency tasked with implementing the provisions of the REC Regulations. The eligible entities include renewable energy generating stations, captive generating stations (based on renewable energy sources), distribution licensees as well as open-access consumers. The precondition for renewable energy generators issuing Renewable Energy Certificates (RECs) is that their tariff should not have been determined or adopted under Sections 62 or 63 of the Electricity Act, 2003, respectively, or the electricity generated/sold in any manner. Additionally, such energy generators should not have availed any waiver or concession of transmission charges or wheeling charges. Further, the renewable energy-based captive generating stations must meet the requirements set for renewable energy generation in order to be eligible to issue RECs. The certificate issued to such captive generating station, to the extent of self-consumption, shall not be eligible for sale. Distribution companies and open-access consumers that purchase electricity from renewable energy sources in excess of the RPO, as determined by the concerned State Commission, shall be eligible for REC issuance to the extent that such excess electricity is purchased from said source. The REC Regulations provide that the price discovery of RECs is to be through power exchange or as mutually agreed between eligible entities and the electricity trader, and further that RECs issued under the REC Regulations shall be valid until they are redeemed.

Judicial decisions, court judgments, results of public enquiries

Dakshin Gujarat Vij Company Limited v. M/s Gayatri Shakti Paper and Board Limited and Batch

The Supreme Court of India in the case of *Dakshin Gujarat Vij Company Limited v. M/s Gayatri Shakti Paper and Board Limited and Batch* has decided the legal issues with regard to requirements for qualifying as a captive power producer and issues incidental thereto in terms of the express statutory provisions. In doing so, the Supreme Court has set aside the decision of the Appellate Tribunal for Electricity (APTEL) in the case of *Tamil Nadu Power Producers Association v. Tamil Nadu Electricity Regulatory Commission*, upheld the decision held by APTEL in the case of *Kadodara Power Pvt. Ltd. and Ors v. Gujarat Electricity Regulatory Commission and Anr*, and held that Rule 3(1)(b) of the Electricity Rules does not negate or undo the eligibility requirements specified in paragraphs (i) and (ii) to Rule 3(1)(a) of the Rules, which, in case of an association of persons, mandates the satisfaction of the proportionality requirement under the second proviso to Rule 3(1)(a). Rule 3(1)(b) refers to a situation where a company set up as a special-purpose vehicle (SPV) has multiple units generating electricity. It stipulates that a company formed as an SPV can identify one or more of such generating units for its captive use, and that not all generating units need to be identified for such use. The units that are not identified for captive use need not satisfy the conditions mentioned in paragraphs (i) and (ii) of Rule 3(1)(a) of the Rules. Electricity generated by these unidentified units need not be accounted for and considered. The explanation clarifies the situation as it states that the requirement of consumption of electricity by captive users shall be determined with reference to the generating unit or units identified for captive use. The unit or units identified for captive use, in other words, must satisfy the requirements of paragraphs (i) and (ii) of Rule 3(1)(a) of the Rules read with the second proviso. This is also clear from Rule 3(2), which states that the equity shares held by the captive user in the generating station, which is identified for captive use, should not be less than 26% of the proportionate equity of the company relating to the generating unit or units identified as a captive generating plant. Thus, Rule 3(1)(b) of the Rules provides flexibility and options when a generating station owned by company, incorporated as an SPV, has multiple generating units. Rule 3(1)(b) does not undo or override the eligibility criteria specified under Rule 3(1)(a) read with the second proviso.

GMR Warora Energy Limited v. CERC and Ors

In the case of *GMR Warora Energy Limited v. CERC and Ors*, the Supreme Court, while addressing the specific issues of Change in Law, held that all additional charges that are payable on account of orders, directions, notifications, regulations, etc., issued by the instrumentalities of the state, after the cut-off date, will have to be considered Change in Law events and that such events have to be accrued from the date on which such rules, orders, notifications, etc., are issued by the state instrumentalities. Notably, the Supreme Court held that distribution licensees are obligated to make timely payments and that a late payment surcharge, which accrues on delayed payments, cannot be equated with carrying cost. It was also held that interest on carrying cost can accrue on a compound interest basis despite any absence of such provision providing compound interest *qua* Change in Law in the specific PPAs. The decision has emphasised the need for timely payments by distribution licensees and the evolution of a mechanism to ensure the same in the interest of the public at large to avoid additional burden on the end consumer due to the ballooning interest on delayed payments.

Paschimanchal Vidyut Vitran Nigam Ltd. v. Raman Ispat Pvt. Ltd. and Ors

The Supreme Court in *Paschimanchal Vidyut Vitran Nigam Ltd. v. Raman Ispat Pvt. Ltd. and Ors* had the occasion to consider whether the dues payable to Secured Creditors should have a higher priority over government dues, including those under the Electricity Act, 2003. As per Section 238 of the Insolvency and Bankruptcy Code, 2016 (IBC), the provisions therein have an overriding effect on the provisions of the Electricity Act, 2003, which entails the primacy of the IBC over any conflicting provisions in other laws. Accordingly, the Supreme Court upheld the IBC's supremacy, in line with previous rulings that have established the position of the IBC as the prevailing law in insolvency matters. The judgment thus underscores the central role of the IBC in insolvency proceedings and its overarching application, even when faced with potentially conflicting statutory provisions.

M/s Dollar Industries Ltd. (DIL) v. Tamil Nadu Generation and Distribution Corporation Limited

In an industry first, the Tamil Nadu Electricity Regulatory Commission (TNERC) in its decision in *M/s Dollar Industries Ltd. (DIL) v. Tamil Nadu Generation and Distribution Corporation Limited* has harmoniously read the provisions of the Electricity Act, 2003 to recognise ESS as part of the power system falling within the ambit of Section 2(50) of the Electricity Act, 2003 in order to allow DIL to set up a 4 MWhr BESS powered by its allied 2 MW solar power plant on the same site. TNERC has observed the need to promote ESS and its adoption and, in pursuance of the same, has not only widened the scope of the Electricity Act, 2003 and the definition of 'power system', but also encouraged establishment of other such projects by categorically observing that they provide a win-win situation for both the generators and distribution licensees.

Tamil Nadu Generation and Distribution Corporation Limited v. CERC and Ors

The issue of whether CERC has the power and jurisdiction to declare any transmission asset as an 'asset of national importance' and to consequently consider 100% yearly transmission charges under the National Component came up before APTEL in *Tamil Nadu Generation and Distribution Corporation Limited v. CERC and Ors.* In its Order, APTEL held that that the subject transmission assets, i.e., those of the Raigarh-Pugalur-Thrissur high-voltage direct current (HVDC) transmission system, are assets of strategic and national importance in line with the other HVDC systems so that the charges are shared on an all-India basis, in light of which CERC unreasonably delayed its decision to consider the same under the components of national importance based on the change in load generation and bi-directional flow of power.

Arinsun Clean Energy Private Limited v. CERC and Ors, *Mahindra Renewables Private Limited v. CERC and Ors* and *Athena Jaipur Solar Power Pvt Ltd. v. CERC and Ors*

In the cases of *Arinsun Clean Energy Private Limited v. CERC and Ors*, *Mahindra Renewables Private Limited v. CERC and Ors* and *Athena Jaipur Solar Power Pvt Ltd. v. CERC and Ors* (Appeal Nos 203/2022, 242/2022 and 248/2022), CERC directed the power producers to enter into PPAs for procuring power required by them during non-generation night hours and during maintenance where the generators were previously complying with the Deviation Settlement Mechanism for such power requirement. Such an alternative arrangement would likely result in a significant financial burden on the power producers as they would be subject to an HT Tariff when executing such independent PPAs.

APTEL

APTEL, by way of its Interim Orders dated 20 May 2022 and 26 May 2022, upon considering the financial adversity that would be caused to the power producers, stayed the operation of CERC's Order and the western RLDC's communications seeking compliance of the same. Further, on 29 May 2023, CERC issued the CERC (Indian Electricity Grid Code) Regulations, 2023, which have categorically allowed renewable energy generators to avail the Deviation Settlement Mechanism for drawl of power during non-generation hours and do not make it mandatory to enter into separate PPAs for the same.

HSA represented Arinsun, Mahindra and Athena before APTEL.

* * *

Acknowledgment

The authors would like to extend special thanks to Mr. Neelkandan Rahate for his contributions.

Hemant Sahai
Tel: +91 98 1008 2892 / Email: hemant.sahai@hsalegal.com
Hemant is the Founding Partner of HSA Advocates, a leading law firm in India, and is recognised by peers, clients and diverse international legal publications as an "astute lawyer" and one of the "leading lawyers" in India. For the last three decades, Hemant has been trusted legal counsel to some of the largest corporates in India and overseas and is widely recognised for his role in shaping the Indian legal industry. In addition to the traditional legal transactional and advisory assignments for corporate groups, Hemant has also been an adviser to central government ministries, PSUs, regulatory authorities, multilateral institutions (World Bank, IFC, ADB, etc.), banks and financial institutions, etc. on a range of policy and regulatory issues.
He has served clients across an array of industries and sectors, including automotive, aviation, banks and financial institutions, e-commerce, education, energy, including renewable energy, environment, health and safety, hospitality and healthcare, infrastructure (urban and rural), insurance, manufacturing, media and entertainment, etc.

Molshree Bhatnagar
Tel: +91 98 1080 9334 / Email: molshree.bhatnagar@hsalegal.com
Molshree is a Partner in the Regulatory & Policy practice group at HSA Advocates. With over 10 years of experience, she has worked with various infrastructure and power companies in disputes of a commercial and regulatory nature. She has been the lead in multiple regulatory litigations undertaken for Vibrant Energy, Serentica, Tata Group, Adani Group, Hindustan Power, Essar Power, GMR, ReNew, ACME, SB Energy, Engie, Sprng Energy, Vena Energy, etc. She has assisted the World Bank, Asian Development Bank, Ministry of Law & Justice and Ministry of Power with their various assignments targeting reforms in India's electricity sector. She is a law graduate of the University of Petroleum and Energy Studies, Dehradun and holds a B.A. LL.B. (Hons) with a specialisation in energy law.

Parichita Chowdhury
Tel: +91 80 9377 0423 / Email: parichita.chowdhury@hsalegal.com
Parichita is a Principal Associate in the Regulatory & Policy practice group at HSA Advocates, New Delhi. She has over six years of experience in which the focus of her practice has been primarily in relation to energy disputes, including on the issues of tariff (generation), Change in Law and *force majeure* events. She is also actively involved in advising power developers with respect to captive power generation/procurement and is currently representing and advising Vibrant Energy, Uttar Pradesh Power Corporation Limited, MB Power (Hindustan Power), Adani Group, GMR Group, Tata Power, Sembcorp Energy, Eden Renewables, Engie India, Jindal Ecopolis, Essar Group, TPDDL, Sprng Energy and Fortum, amongst other prominent power sector developers/procurers.

HSA Advocates
81/1, Adchini Sri Aurobindo Marg, New Delhi – 110 017, India
Tel: +91 11 6638 7000 / URL: www.hsalegal.com

Japan

Sadayuki Matsudaira & Tomohei Minatogawa
Nishimura & Asahi

Overview of the current energy mix, and the place in the market of different energy sources

The Japanese government enacted the Sixth Fundamental Energy Plan in October 2021, setting the following percentages for power generation mix in 2030: 36–38% renewables; 1% hydrogen and ammonia; 20–22% nuclear; 20% natural gas; 19% coal; and 2% oil. The breakdown of the 36–38% total for renewables is 11% hydro, 14–16% solar, 5% wind, 1% geothermal, and 5% biomass.

In comparison, power generation mix in 2021 was composed as follows: 7% nuclear power; 34% natural gas; 31% coal; 7% petroleum; and 20% renewables, made up of 7.5% hydropower, 8.3% solar power, 0.9% wind power, 0.3% geothermal power, and 3.2% biomass.

There is no change in the direction of the government, including the composition of the power generation mix shown in the Sixth Fundamental Energy Plan.

Changes in the energy situation in the last 12 months that are likely to have an impact on future direction or policy

Long-term decarbonised power resource auction

This is a bidding system for new investments in decarbonised power resources. The bidding system implements bidding for mixed types of power resources. The successful bidder receives the advantage of predictable long-term income for the recovery of a large initial investment, by making capacity revenue with a fixed cost level, in principle, earned over 20 years.

It is positioned as a type of capacity market, as it provides the predictability of long-term income by making the period for obtaining capacity revenue multiple years rather than a single year. The first auction is scheduled to be conducted in FY 2023.

The bidding system targets new investments in the construction and replacement of decarbonised power resources, and the renovation of existing thermal power plants for decarbonisation. The targets include storage batteries and thermal power generation by mono-firing and co-firing of hydrogen and ammonia.

In FY 2023, the total of the initial auction for decarbonised power resources is 4GW on a bid-volume basis, projects for the renovation of existing thermal power plants (co-firing of ammonia and hydrogen and mono-firing of biomass) is 1GW, and the sum of storage batteries and pumped hydropower is 1GW.

Although, in principle, the minimum bidding volume is 100MW, the minimum bidding volume is reduced to 10MW for storage batteries and to 50MW for renovation projects for mono-firing and co-firing of ammonia and hydrogen in existing thermal power plants, and new construction and replacement projects for mono-firing and co-firing of hydrogen and ammonia are considered 100MW.

The business operator bids at a price that contributes to the recovery of the investment, and a maximum bid price is set for each auction. A multiple-price method is adopted, whereby the winning bid price for the power resources is the contracted price. As a general rule, power resources are awarded in priority order, by lowest bid price.

After the bid, the bid price is monitored by the Electricity and Gas Market Surveillance Commission. Monitoring requires the submission of contracts, estimates, etc., as well as an explanation of the methods and grounds for calculating bid prices.

The deadline for starting capacity supply for the storage battery projects is the end of the fiscal year four years after the date of the contract to be executed in relation to the successful bidding, and the deadline for the installation, replacement, and renovation of new projects involving mono-firing and co-firing of hydrogen and ammonia is the end of the fiscal year 11 years after the date of the contract to be executed in relation to the successful bidding (for projects that have implemented an environmental impact assessment pursuant to applicable laws or ordinances, the deadline is the end of the fiscal year seven years after the date of the contract to be executed in relation to the successful bidding). If the deadline for starting capacity supply is exceeded, the period during which the bid price can be received will be reduced by a period equal to the excess period. During that excess period, the award price for the current capacity market shall be the capacity revenue. In addition to this and the current capacity market requirements, unique requirements and penalties are established for the long-term decarbonised power resource auction.

The successful bidder executes a capacity securing agreement with the Organization for Cross-regional Coordination of Transmission Operators, and is paid the amount of the capacity securing contract. Capacity contributions paid by electricity retailers, etc., will be used as financial resources to cover the amount of the capacity securing contract. Fixed-cost equivalents are paid over 20 years.

The long-term decarbonised power resource auction is expected to be utilised in future project finance for storage batteries and thermal power plants that operate by mono-firing and co-firing of hydrogen and ammonia.

Hydrogen and ammonia

In 2017, Japan formulated the "Basic Hydrogen Strategy", the world's first national hydrogen strategy, and by 2022, 26 countries and regions, including Japan, had formulated a hydrogen strategy. Five years have passed since the establishment of the Basic Hydrogen Strategy, during which time we have witnessed two landmark events. The first is Japan's declaration on carbon neutrality by 2050. The Sixth Fundamental Energy Plan, which was revised based on this declaration, states that approximately 1% of the power generation mix for FY 2030 will be covered by hydrogen and ammonia. Hydrogen and ammonia are positioned to play a role in the future of Japan's energy supply. The second is Russia's aggression against Ukraine in February 2022. Consideration is being given to building a large-scale and resilient supply chain for hydrogen and ammonia, and to supporting the development of supply infrastructure.

In view of Japan's energy demand, while there is a limit to the expansion of the domestic hydrogen market, the Basic Hydrogen Strategy has been revised on the grounds that it is necessary while keeping in mind the incorporation of overseas markets, in light of the fact that the market is spreading at once, with the global hydrogen market expected to generate annual revenues of USD 2.5 trillion and job creation of 30 million people by 2050.

In this strategy, in addition to the country's overall policy on hydrogen policy, the "hydrogen industry strategy", which is a new policy for strengthening the industrial competitiveness of hydrogen, and the "hydrogen safety strategy", which is a policy for the safe utilisation of hydrogen, will be incorporated as important pillars. The strategy is to be reviewed at an appropriate time, within roughly five years. Ammonia and synthetic fuels are also subject to this strategy.

With the situation in Ukraine and the global energy crisis, countries are making huge investments in hydrogen. As a country with advanced hydrogen technology, Japan is calling for the transition to low-carbon hydrogen, and it is urgently proceeding with the development of a pioneering system, leading Asia in integrated forms of regulation and support.

Specifically, the development of a system for building a large-scale and resilient supply chain is under consideration. The scheme is to provide long-term support (in part or in whole) for the difference between the base price (the price at which it is expected to earn a reasonable return while recovering the cost of business continuity) and the reference price (the equivalent price of existing fuel) for hydrogen and ammonia supplied by a business operator (the first mover), in which the business operator invests, taking its own risks ahead of other business operators, and starts supplying low-carbon hydrogen and ammonia in Japan by around 2030. At present, public-private investment in the supply chain is projected to exceed JPY 15 trillion in 15 years.

In addition, support for the development of supply infrastructure, such as tanks and pipelines, will be provided in order to create large-scale demand and realise an efficient supply chain that enables stable and inexpensive supplies of hydrogen and ammonia and encourages internationally competitive industrial clusters.

Developments in government policy/strategy/approach

<u>Basic policy for the realisation of GX</u>

In February 2023, the basic policy for the realisation of the Green Transformation ("GX") was formulated based on the Sixth Fundamental Energy Plan. The transformation of fossil energy-centric industrial and social structures to clean energy-centric, which is the concept behind GX, represents a major shift in post-war industrial and energy policies.

GX aims to reduce greenhouse gases by 46% by FY 2030 and fulfil the 2050 carbon-neutral international pledge. At the same time, the policy for the next 10 years is set with a view to realising a shift in the energy supply-demand structure that will lead to a stable and inexpensive energy supply.

One of the policies is to make renewable energy a major power source, while mitigating the burdens on private citizens and seeking harmonious coexistence with local communities. It aims for steady growth to achieve a level of 36–38% renewable energy in the power generation mix by FY 2030, based on the premise of S+3Es (Safety, Energy security, Economic efficiency, and Environment).

In addition, nuclear power generation, which does not emit CO_2 and is stable in terms of output, contributes to the realisation of carbon-neutral and stable energy supplies; in the 2030 power generation mix set forth in the Sixth Fundamental Energy Plan, the percentage of power generated by nuclear energy sources is 20–22%. To advance this goal, while making safety a top priority, Japan is proceeding with the reopening of nuclear reactors that have passed a safety review by the Nuclear Regulation Authority and have gained the understanding of local communities.

In addition, hydrogen/ammonia, which can be co-fired with fossil fuels, is expected to reduce CO_2 emissions from thermal power generation and support the transition period toward carbon neutrality. In order to build a large-scale and resilient supply chain domestically and internationally, consideration will be given to increasing the predictability of businesses, focusing on differences in prices compared to existing fuels.

In addition, in order to improve the business climate for the commencement of carbon capture and storage ("CCS") projects by 2030, the development of legislation that takes into account the business risks and safety associated with the storage of CO_2 underground will be accelerated.

Developments in legislation or regulation

<u>Consideration of a CCS law system</u>

In March 2023, the council of the Ministry of Economy, Trade and Industry ("METI") published a report regarding the CCS Business Act (tentative name).

In order to smoothly implement CCS projects, it is necessary to include certain businesses in the value chain, from the separation and capture of carbon dioxide to the underground storage in the range of the law.

In addition to underground storage businesses, which are key to CCS business, transportation businesses (pipelines, ships, and tank trucks) and separation and capture businesses are considered appropriate targets for coordination.

In particular, it is necessary to pay attention to the fact that, for the time being, the number of companies with knowledge and technology on underground structures is limited, and natural monopolisation is likely to occur in underground storage businesses.

There are many issues relating to the CCS legislation, and further consideration is required.

<u>Revision of the Act on Special Measures Concerning Promotion of Utilization of Electricity from Renewable Energy Sources</u>

The Law for Partially Amending the Electricity Business Act and Other Acts to Establish an Electricity Supply System to Achieve a Decarbonized Society was promulgated on June 7, 2023, and will come into force on April 1, 2024. Article 4 of the Act partially revises the Act on Special Measures Concerning Promotion of Utilization of Electricity from Renewable Energy Sources ("Renewable Energy Special Measures Act").

The specific contents of the amendment are as follows:

(1) In the event that a renewable energy power generation facility satisfies the requirements specified by an Ordinance of METI with regard to output and other matters, the renewable energy power generation business plan must record that an explanatory meeting has been held for residents in the area surrounding the site where the renewable energy power generation facility will be located, along with a description of the state of implementation of other measures, as specified in an Ordinance of METI, in order to resolve the lack of communication with, and address the concerns of, the region. Implementation of the measures will be a requirement for certification of the business plan.

The METI council materials state that explanatory meetings are required for certification of the business plan of large-scale power sources, and will serve as a preliminary method of notification for the relevant local community. For small-scale power sources, measures such as prior installation of signs containing certain items, such as the content of business plans, posting them on the websites or in the leaflets of business operators, or publicising them in advance, are being considered, and may be requirements for certification of the business plans of those smaller operators. Methods of preliminary notification of briefings and the contents of common requests for briefings are being considered, and also may be set forth in the Ordinance of METI and the Guidelines.

(2) The Act also states that a certified business operator shall carry out the power generation business in accordance with the certified business plan, and that if the business related to the power generation business is to be consigned, necessary and appropriate supervision of the consignee shall be carried out so that the power generation business is carried out in accordance with the certified plan.

According to the METI council materials, the certified business operator's responsibility under the current system when a consignee violates the certified plan is unclear. Thus, the purpose of the Act is to clarify this responsibility in the text of the statute. A guideline establishing the matters to be included in the contract between the certified business operator and the consignee (e.g., a periodic reporting system, prior consent of the certified business operator at the time of re-consignment, etc.) is being considered.

(3) As a mechanism for helping to prevent violations of laws and regulations by certified business operators, or to resolve any violations promptly, it was decided that if a certified business operator violates its certified plan, it will be subject to a new obligation to reserve funds, based on a reserve order, that will suspend the payment of the FIT/FIP premium. In addition, an obligation to set aside reserve funds for decommissioning, which is being imposed from the perspective of securing costs for proper decommissioning of facilities, will be imposed separately from this measure.

If the Minister of METI rescinds a certified business plan due to non-compliance, the certified business operator shall return an amount equal to the whole or part of the total FIP premium subsidies obtained.

(4) With the aim of encouraging the renewal and expansion of solar panels, the current legislation states that when the output increases, the procurement price or standard price of the power generation facility shall be adjusted in its entirety to the latest price, in order to prevent an increase in the burden on the public. However, under the new Act, when there is an expansion or partial renewal of a power generation facility that is specified by an Ordinance of METI, and when an application for certification of changes to the certified business plan is filed, the portion of the application relating to the existing facility and the portion relating to the expansion may be stated separately. If the change is certified based on this distinction, the standard price or procurement price for the existing facility shall be deemed to fall within the prior and existing category of delivery target or procurement target, and the procurement price or standard price is calculated using the method specified in an Ordinance of METI, based on the procurement price or standard price of the existing portion and the part relating to the expansion.

(5) The following is not included in the amendment to the Renewable Energy Special Measures Act but will be established by an Ordinance of METI.

The current law does not require the acquisition of approvals and licences for various related laws and regulations at the stage of application for certification of the business plan. However, there have been cases in which compliance with the relevant laws and regulations has not been carried out thoroughly, although a pledge to comply with the relevant laws and regulations is a required part of the form for application for certification. The following types of land development-related licences that may directly affect the risk of disasters are particularly closely related to the safety of the surrounding area, and it is extremely difficult to restore the land to its original state once the actions subject to the licence have been conducted. Therefore, it is necessary to enforce the procedures for the certification strictly, for example, by requiring the acquisition of licences to apply for FIT/FIP certification:

(a) Forest land development permit under the Forest Act.
(b) Permission under the Act on Regulation of Residential Land Development and Specified Embankments.
(c) Permission under the Erosion Control Act, Landslide Prevention Act and Act on Prevention of Disasters Caused by Steep Slope Collapses.

All renewable energy generation facilities located in areas where it is necessary to obtain approvals and licences above will be required to obtain the relevant approvals and licences before applying for certification of the relevant business plan. However, approvals and licences for wind power and geothermal power generation projects that are subject to environmental impact assessment procedures based on laws or ordinances may be obtained after certification.

Revisions to METI Ordinances and guidelines to implement stricter certification procedures are being considered, with a certain period in place to allow for public awareness, in order to implement them promptly. Further approvals and licences may be added.

<u>Generation charge</u>

According to an interim report by the METI council, a generation charge is scheduled to be introduced in April 2024.

A generation charge is part of the cost necessary for maintenance and expansion of the transmission and distribution facilities, in order to utilise and expand the utility grid efficiently and reliably for the introduction and expansion of renewable energy; this charge is borne by electricity generation utilities, which are users of the utility grid together with consumers.

Under the current wheeling charge system, the cost of grid enhancements associated with the introduction of renewable energy power sources is borne by consumers in the relevant area, through wheeling charges imposed on electricity retailers in that area. However, after the introduction of the generation charge, the electricity generation utility will bear part of the cost of expansion of the utility grid, and by adding an amount equivalent to that generation charge to electricity charges, it will be possible for consumers who purchase electricity from the relevant electricity generation utilities to bear the cost.

The chargeable target of the generation charges is basically all power sources connected to the grid and having reverse power flow to the grid. This will be done from the perspective of benefit and burden, so as not to give an advantage or disadvantage to a specific power source. The generation charge will be carried out by two methods: a kW-based charge; and a kWh-based charge.

The METI council is discussing how to pass on generation charges from electricity generation utilities to electricity retailers, and is considering formulating guidelines for this purpose, to ensure that the utility grid will be utilised efficiently and expanded steadily, by passing on the charges to electricity retailers (as part of the electricity generation charge) and then passing the cost on to consumers.

Some corporate power purchase agreement contracts also contain provisions for the introduction of a generation charge, and some agreements have been reached that require the consumer to bear costs equivalent to the generation charges incurred by the electricity generation utility.

Judicial decisions, court judgments, results of public enquiries

An example of a recent conflict with a neighbourhood in which there are solar power plants involves the problem of reflected light by solar panels.

In the case of wind power plants, there has been a dispute between the construction company for offshore wind power generation facilities and the fishermen who opposed it. Since fishery rights are property rights, and are regarded as real rights, it is possible to institute a lawsuit against infringement of these rights, such as the exercise of the right to eliminate obstruction and the right to prevent obstruction, and the right to claim compensation for damages in tort. There are cases in which an injunction on construction work has been requested.

Sadayuki Matsudaira
Tel: +81 3 6250 6256 / Email: s.matsudaira@nishimura.com
Sadayuki Matsudaira's main practice areas are transactions, projects, and regulatory matters in the energy sector. Sadayuki advises international and domestic clients on a variety of energy-related areas, such as power plants, gas terminals, networks, and energy wholesale and retail businesses. He is the Regional Vice-Chair for Asia Pacific of Lex Mundi's Energy Group. He was selected as a Leading Individual in Projects and Energy in *The Legal 500 Asia Pacific 2021*.

Tomohei Minatogawa
Tel: +81 3 6250 6637 / Email: t.minatogawa@nishimura.com
Tomohei Minatogawa's main practice areas are transactions, projects, and regulatory matters in the energy sector. Tomohei advises international and domestic clients on a variety of energy-related areas, such as power plants and energy wholesale and retail businesses.

Nishimura & Asahi
Otemon Tower, 1-1-2 Otemachi, Chiyoda-ku, Tokyo 100-8124, Japan
Tel: +81 3 6250 6200 / URL: www.nishimura.com

Norway

Margrethe Antonsen Lilleng & Jon Rabben
Wiersholm AS

Overview of the current energy mix, and the place in the market of different energy sources

Norway is known for its vast natural resources and commitment to sustainable energy. Over the past 12 months, significant developments have occurred in the energy sector.

Initially, it is worth mentioning that Norway is a part of the European Economic Area (EEA), and through this, participates in the European Union's (EU) Internal Energy Market (IEM). Consequently, EU legislation that is not implemented in the EEA Agreement will not directly apply to Norway. However, it may indirectly influence Norway through its effects on the European energy market, which is Norway's most important export market for oil, gas, and electricity.

This section aims to provide an insight into Norwegian energy production and consumption, as well as the different energy sources and products.

Energy production

In 2022, the total energy production (https://www.ssb.no/statbank/table/11562) showcased a diverse range of energy products, highlighting the various energy sources contributing to the energy landscape. Energy production included electricity generation (146.7 TWh), primarily from hydropower and wind power, and district heating (7.3 TWh). Norway also produced substantial quantities of natural gas (128,052 million standard cubic metres) and oil (100,424 kilotons), excluding biofuels. Additionally, biofuels and waste contributed 3,029 kt and 1,499 kt, respectively, while coal and related products amounted to 666 kt.

	Quantity (see energy product)
	2022
	1 total production
Coal and coal products (kilotons)	666
Natural gas (mSm3)	128,052
Oil and oil products (excl. bio) (kilotons)	100,424
Biofuels (kilotons)	3,029
Waste (kilotons)	1,499
Electricity (GWh)	146,731
District heating (GWh)	7,277
Energy products n.e.c (GWh)	0

Table 1[1]

Energy consumption

The total energy consumption for 2022 in Norway was distributed across various industries and energy products. Electricity consumption was 133.5 TWh, fossil fuels accounted for

59.8 TWh, gas consumption was 65.4 TWh, and bioenergy contributed 17.2 TWh. Other oil products amounted to 22.2 TWh, district heating represented 7.1 TWh, coal consumption was 8.5 TWh, and heating oil had a minimal share of 0.95 TWh.

Product	TWh
Other oil products	22.2
Bioenergy	17.2
District heating	7.1
Fossil fuel	59.8
Fuel oil	0.95
Gas	65.4
Coal and coke	8.5
Electricity	133.5

Table 2[2]

The onshore industrial sector accounts for the highest consumption at 71.2 TWh, followed by the petroleum industry with 63.2 TWh. The transportation sector also has a significant share with 55.9 TWh. Households in Norway contribute to 44.7 TWh of energy consumption, while service industries stand for 34.6 TWh. The raw material industry utilises 23.3 TWh, and grid usage and self-consumption amount to 10.5 TWh. Lastly, other consumption, which includes miscellaneous energy uses, reaches 11.8 TWh.

Sector	TWh
Other consumption	11.8
Households	44.7
Industry	71.2
Network loss and private consumption	10.5
Petroleum industry	63.2
Raw materials industry	23.3
Provision of services	34.6
Transport	55.9

Table 3[3]

Energy sources and products in the Norwegian market

Nearly all gas and the majority of oil produced on the Norwegian continental shelf are exported to consumers in international markets. Fossil fuels are primarily consumed domestically in the petroleum sector and the transport sector, as well as to some extent in the industry. The central sources of energy for stationary consumption in industry and households are electricity and bioenergy.

In the last 10 years, a shift has occurred, with gas sales exceeding oil sales when measured in oil equivalents. This change contrasts with the period between 1985 and 2010 when oil production was considerably higher than gas production. However, discovered resources have experienced a reduction of 72 million Sm³ o.e. when compared to the figures from 2021.

As the overview demonstrates, there are several significant energy commodities in the Norwegian energy mix. The focus in what follows will be on the domestic energy mix, with electricity and its associated energy sources as the dominating feature. Other categories of energy products that have experienced legal developments over the past year will also be referenced throughout the chapter, ensuring a comprehensive analysis of the evolving energy landscape.

During an average year, Norway generates around 156 TWh of electric energy. In recent years, there has been significant growth in power infrastructure, and subsidies promoted through an electricity certificate system have contributed to more than 19 TWh of new renewable energy primarily from wind power.

Key figures for Norwegian power production as of 31 March 2023 show that most of Norway's electricity generation comes from hydropower, with wind power as the only addition of significance. With an installed capacity of 33,730 MW, the hydroelectric power plants in Norway on average generate 136.9 TWh of electricity each year. The wind power plants, boasting an installed capacity of 5,083 MW, contribute an additional 16.9 TWh annually. In total, Norway has 1,864 power plants with an installed capacity of 39,455 MW and an average yearly production of 156.9 TWh.

Changes in the energy situation in the last 12 months that are likely to have an impact on future direction or policy

There is no doubt that 12 months can make a difference in this fast-evolving sector. This section will illustrate how rapid changes in energy markets, development of power consumption, profitable power production and security of supply have affected the Norwegian strategies and directions over the past year.

Evolving cost and availability of exported energy resources

The last year has been dominated by the energy shortage that arose in Europe due to the cessation of Russian gas and the war in Ukraine. This had a considerable influence on Norway's export-orientated petroleum industry in various aspects and affected domestic energy prices and security of supply issues.

One sign was the price increase for oil and gas. The export value of oil and gas was three times higher last year, in comparison to the past decade. The energy crisis made Norwegian gas production even more critical for European energy security and led to new measures to address energy security and availability of resources.

Decarbonisation goals and strategies in the face of global challenges

The main goal from a domestic perspective is to continue having a power surplus and sufficient access to renewable energy, providing competitive prices in the future. The realisation of climate goals and the green transition entails increased power consumption and electrification of multiple sectors. Therefore, the need for increased renewable power production, energy efficiency and upgrades, as well as grid expansions, is evident.

In early 2023, the Energy Commission, appointed by the Norwegian Ministry of Petroleum and Energy, released its report, after being assigned to map the future energy needs in Norway and propose measures for increased power production. The message is that we need to expand the scope of increased renewable power production, energy efficiency, and grid expansions, and the lead time must be reduced. Environmental concerns and local opposition create challenges in meeting this demand. In addition, climate change and the consequences of the war on the continent show that the future is unpredictable and changing. The Commission points to the necessity of clear political guidance.

In alignment with the EU's emission policies, the goal is to reduce Norway's greenhouse gas emissions by 55%, combined with an estimated electricity consumption increase of up to 75 TWh, by 2030. Estimates indicate a rise of up to 24 TWh from electrifying the industrial and petroleum sectors, along with a 44–60 TWh increase in the transport sector by 2050. To meet this demand, the Energy Commission set a goal for where we should be at the onset of the 2030s. The objective should encompass a minimum 40 TWh increase in renewable power production sourced from hydropower, wind power, offshore wind, and solar power. In addition, a minimum 20 TWh improvement in energy efficiency is advised. Several changes in government policies and strategies will need to be developed, to successfully achieve this substantial increase in production and energy efficiency, within a seven-year period.

High electricity prices, market changes and grid capacity

The average electricity price in Norway has increased significantly in the last couple of years, driven by a number of factors, including the war in Ukraine, increased demand for electricity in Europe, and reduced hydropower production due to low reservoir levels. This has put a strain on household and business budgets and has led to calls for government intervention to reduce the impact of high prices.

The EU Commission's proposal of 14 March 2023 for a reform of the EU's electricity market design to promote investments in renewable energy, provide better consumer protection against fluctuating energy prices, strengthen industrial competitiveness, and contribute to the EU's dual goals of energy sovereignty and climate neutrality will also affect future energy policies in Norway. The Commission's reform proposal comes in the form of two legislative acts, which will revise multiple directives and regulations that are all under consideration for incorporation into the EEA Agreement.

Furthermore, it became evident in 2022–2023 just how critical network capacity is for Norway to achieve climate goals and ensure the security of supply. The demand has virtually exploded, with new grid capacity equivalent to 30% of today's capacity being ordered.

Long lead times can impede societal development, as it may take eight to 10 years for new capacity to be in place after ordering. Much of the time spent is due to lengthy concession processes. In a recently released report from an *ad hoc* Electricity Grid Committee, proposals were made to reduce lead times for new grids by streamlining current processes instead of radical changes.

Developments in government policy/strategy/approach

General policy intentions

As evidenced by developments mentioned above, there is a necessity for revitalised policy efforts in the Norwegian energy sector. To address these challenges, the Norwegian Government appointed two independent public commissions to investigate various aspects of Norwegian energy policy. The Energy Commission, as mentioned above, was appointed in 2022 to assess the fundamental dilemmas of Norwegian energy policy towards 2030 and 2050. In 2021, the Electricity Grid Commission was appointed to investigate how the high electricity prices in Norway can be reduced. Both commissions proposed several measures, including the following.

Measures to promote efficient and flexible energy use

The Energy Commission emphasises the need for more efficient and flexible energy use by further developing the overall energy system and heating systems and achieving smart energy use that is energy-efficient, digital, flexible, and responsive to price.

To achieve this, the committee proposes a comprehensive energy efficiency plan with clearly anchored responsibility for coordination and follow-up. The provided proposal includes energy management for all industrial enterprises to identify efficiency improvement opportunities and investments. Utilising more surplus heat generated from the industry is also suggested.

Reducing energy consumption in new and existing buildings is emphasised, with a proposed national efficiency drive for residential, multi-family, and commercial buildings until 2030. Another proposal is using local heating resources, including district heating, more extensively.

Measures to increase power production

The Energy Committee proposes increased value creation for municipalities affected by wind power developments and measures to promote acceptance. For offshore wind, the focus is on clarifying framework conditions and allocating areas for projects by 2030. The committee believes that 5–20 TWh of offshore wind production should be in place by 2030. A long-term plan for offshore wind and grid development is needed.

To facilitate more solar power development, the Energy Commission believes that current regulations should be amended to include decentralised production. The committee also points out that a more comprehensive policy for solar power must be developed.

Regarding nuclear power, the committee assumes that it is not a solution for Norway now but that "Norway should continuously follow international developments in nuclear power technology and safety".

Measures to reduce lead time

The Energy Commission aims to halve concession and case processing times for power and grid developments. Improved efficiency will promote new production without compromising quality. Clear political priorities and consideration of European processes are essential to avoid falling behind neighbouring countries. Proposals include early stakeholder involvement, prioritised application processing, parallel processes, and case handling deadlines.

Measures to increase network capacity

The Electricity Grid Committee was appointed by royal resolution on 11 June 2021 to assess measures for reducing the time it takes to develop and process concessions for new grid facilities. The Energy Commission endorsed the Electricity Grid Committee's recommended measures, while also presenting additional proposals. Among these are a proposal that network development should occur before specific consumption needs arise, better assessments of how network operators can prioritise between areas and customers, and a proposal to promote enhanced grid availability by reducing reserve requirements on grid operators.

Organisation of the power sector: Interconnections and security of supply

Recently, there has been an increased focus on security of supply and the debated significance of interconnectors. The Energy Commission highlights that the interconnectors will strengthen the security of supply due to the need of imports during dry years, which will increase due to climate change causing greater variations in inflow. As a result, the Energy Commission proposes assessing the societal rationality of renewing cables when concession periods expire and investigating the need for new cables.

To ensure supply security, the importance of hydropower as a regulatable energy source and its vulnerability during dry years has been highlighted. Consequently, proposals include establishing regulations for reservoir management and considering export limitations when strictly necessary, which is currently being evaluated by the Government.

Clean hydrogen adoption and strategy

The Norwegian Government's hydrogen strategy from 2020 contributes to the development of new low-emission technologies and solutions towards 2050. The subsequent roadmap from 2021 envisions a market for the production and use of hydrogen by 2050. In the short term, by 2025, the Government plans to facilitate the establishment of five hydrogen hubs focusing on maritime transport in collaboration with private entities. It also aims to initiate one or two industrial projects with corresponding production facilities and between five and 10 pilot projects for the development and demonstration of new and more cost-effective hydrogen solutions and technologies.

Norway has approximately 126 early-stage hydrogen projects in the pipeline, which could result in an electrolysis capacity of 4 GW by 2030. An electrolysis capacity of 4 GW would be enough to produce around 1 million tonnes of hydrogen per year. The significant number of early-stage hydrogen projects indicates substantial interest in the development of a hydrogen economy in Norway. However, many aspects need to be addressed, including legislation, framework conditions, market, and technology. A Konkraft[4] report estimates that Norway could supply 1 million tonnes of hydrogen to the EU by 2030, but an economically viable value chain remains to be developed. This includes developing the infrastructure to produce, store, and transport hydrogen. It also includes securing buyers for Norwegian hydrogen.

The Norwegian and German Governments have signed a joint declaration of intent to develop a hydrogen partnership. This partnership aims to put in place large-scale deliveries of hydrogen from Norway to Germany by 2030. This declaration has been followed by significant corporate initiatives.[5]

In 2022, NOK 1.98 billion was allocated to various hydrogen projects in the shipping industry. In total, 10 ships received support commitments from Enova to transition to hydrogen and ammonia as fuel. However, so far, this support has not led to a single investment decision, as stakeholders believe that the funding is insufficient and the risk too high. Norway's Minister of Petroleum and Energy has expressed disappointment that the initiative remains unused but cannot promise that the support will be expanded.

The industry strongly demands Contracts for Difference (CfD) as a measure to support new hydrogen production in Norway. Such contracts involve the state subsidising the price difference between fossil fuels and hydrogen. The latter is currently up to four times more expensive than gasoline and diesel. Following this industry initiative, the Norwegian Parliament asked the Government to present a plan to introduce a system for CfD for hydrogen during 2023.

The Government aims for Norwegian projects to participate in the forthcoming hydrogen auction under the EU's Innovation Fund. The programme will provide five-year support for the production of green hydrogen and is scheduled to be implemented by the end of 2023, with a budget of EUR 800 million. This initiative is dependent on Norway implementing recent changes in the EU's Emissions Trading System (ETS), which are currently being reviewed by the Parliament.

Norwegian offshore wind strategies

Norway aims to become a leading nation in offshore wind, with an industry that develops and constructs top-class wind power solutions. The Government's ambition is to allocate areas with the potential for 30 GW of offshore wind production on the Norwegian continental shelf by 2040.

In 2020, the first areas on the Norwegian continental shelf were opened for renewable energy production at sea, and since then, the authorities have been working to establish regulations in close collaboration with the industry and other stakeholders. On 29 March 2023, the Ministry of Petroleum and Energy announced a competition for the project areas for offshore wind in Sørlige Nordsjø II (SNII) and Utsira Nord.

SNII will be developed with bottom-fixed foundations. A prequalification process was due to be conducted for SNII in the autumn of 2023, with criteria such as implementation capability (60%), sustainability (20%), and positive local ripple effects (20%) being emphasised. Actors who meet the minimum criteria will be ranked. Based on an overall assessment, the Ministry will prequalify a minimum of six and a maximum of eight actors according to the ranking. The prequalified actors will be allowed to compete for the allocation of project areas during spring 2024.

The Parliament has granted the Government full authority to enter into a bilateral CfD for support to offshore renewable energy production, from the first phase of SNII. On 20 September 2023, the Ministry of Petroleum and Energy released a draft CfD for SNII, which entails maximum financial support of NOK 23 billion over a 15-year period. The contract price is a fixed rate per kilowatt-hour (kWh), with the state and offshore wind producers compensating each other for price differences when market prices deviate from the contract price.

For Utsira Nord, which will be developed with floating foundations, the allocation of project areas will be carried out through a competition based on qualitative criteria during autumn 2023 and spring 2024. After the application deadline, the Ministry will assess whether the applicants have satisfactory technical competence and financial strength and meet relevant health, safety, and environmental requirements. Applicants who meet the requirements will be ranked according to the qualitative criteria. The three applicants who achieve the highest overall score in the qualitative competition will each be awarded a project area. There will be a later competition for subsidies among the parties being awarded development areas.

The Norwegian Water Resources and Energy Directorate (NVE) has identified potential new areas for renewable energy production at sea. The work has been carried out by a joint directorate group consisting of the Norwegian Petroleum Directorate, the Directorate of Fisheries, the Environment Agency, the Norwegian Coastal Administration, the Norwegian Defence Estates Agency, and the Directorate for Civil Protection and Emergency Planning. The work was presented to the Minister of Petroleum and Energy on 25 April 2023, and the allocation of project areas is expected to happen in 2025.

Developments in legislation or regulation

The Norwegian Government has a long history of supporting renewable energy and energy efficiency, and during the last 12 months, the Government has announced a number of new regulatory measures to support the energy transition.

<u>Electricity support schemes for consumers and industry</u>

In response to the escalating electricity prices, the Norwegian Government has implemented two temporary electricity support schemes aimed at alleviating the financial burden on both households and businesses.

The first scheme, known as the consumer scheme, was launched in December 2021. It offers a substantial 90% rebate on electricity prices exceeding NOK 0.70 per kWh. This scheme is accessible to all households, with a cap on the rebate set at 5,000 kWh per month. The second scheme, designed for the industry, was introduced in September 2022. It provides a 25% rebate on electricity prices over NOK 0.70 per kWh. This scheme is available to businesses with a minimum electricity intensity of 3%. Furthermore, businesses can qualify for an additional 20% rebate if they pledge to implement energy efficiency measures within a two-year timeframe.

Enhancing efficiency and utilisation of grid connections

In response to an assignment from the Norwegian Ministry of Petroleum and Energy, the Norwegian Energy Regulatory Authority (RME) has recently recommended a series of regulatory changes aimed at improving the efficiency of grid connections and promoting better utilisation of the existing network capacity. These changes are expected to have a significant impact on the energy sector, particularly in terms of grid connection processes, tariff regimes, and revenue regulation.

One of the key proposals put forward by RME is the introduction of new maturity requirements for grid connections. These requirements are designed to ensure that only well-prepared and viable projects are granted access to the grid, thereby reducing the risk of delays and inefficiencies in the connection process.

Another important aspect of the proposed changes is the requirement for grid operators to report time usage in grid connection processes. This measure is intended to apply pressure on grid operators and project developers to reduce the time spent on connections, ultimately leading to increased efficiency and cost savings.

RME is also considering the implementation of new tariff regimes to encourage the establishment of grid infrastructure before consumer demand materialises. This proactive approach is expected to help alleviate potential capacity constraints and ensure that the grid is well equipped to handle future demand growth. By adopting forward-looking tariff structures, RME aims to create a more flexible and resilient energy system that can adapt to changing market conditions and consumer needs.

Introduction and abolition of the excise duty (also called the high-price contribution)

In 2022, as part of the 2023 state budget, the Norwegian Government introduced a high-price contribution for hydropower, which resulted in large hydropower plants being charged a gross fee of 23% of the electricity price in excess of NOK 0.70 per kWh. From January 2023, this fee was also imposed on concession-bound wind power plants.

The fee has met significant opposition and, according to industry voices, has made it both unpredictable and unprofitable to invest in new power production. The Government has now announced that the high-price contribution will be abolished from 1 October 2023. This proposal is dependent on the Parliament's approval, expected in December 2023.

Developments in the resource rent tax scheme

In Norway, resource rent tax has traditionally been imposed on top of ordinary corporate taxes for businesses exploiting natural resources. This has traditionally included hydropower producers, which are subject to resource rent tax of 45% (increased from 37% in 2022) on top of the ordinary 23% corporate tax rate applicable in Norway. The resource rent tax is based on norm prices; for hydropower producers, the spot price quoted on Nord Pool.

There are certain important exceptions from the norm price regime, including an exception for long-term supply agreements with certain types of power-intensive industry. In these cases, the resource rent tax will be based on the contract price. As a measure to relieve Norwegian businesses from the risks attached to the current unstable energy markets, the Government has recently adopted a substantial extension of the norm price exception, allowing power supplies to all Norwegian businesses (three to seven years) to be taxed based on the contract price. The proposal is intended to facilitate a more liquid market for fixed price agreements between hydropower producers and Norwegian businesses.

In the recently launched proposed state budget for 2024, the Government proposes to introduce resource rent taxation also for onshore wind power. The proposed effective tax rate is 35%, and changes are proposed to take effect from income year 2024. The proposed resource rent tax is designed as a cash flow tax with immediate deductions for new investments. The tax will apply to wind power plants consisting of more than five turbines or that have a total installed capacity of 1 MW or more. No payout scheme is proposed for negative resource rent income. Instead, negative resource rent income can be carried forward with risk-free interest and be deducted from future positive resource rent income for the individual wind power plant.

Amendments in the concession regime for onshore wind power

As mentioned above, significant amounts of new onshore wind power capacity have been put into operation in Norway during the last five years. However, due to rising concerns over nature conservation issues and the rights of neighbours and (in the northern parts of Norway) indigenous reindeer herders, this development has come to a halt. In 2019, the Government decided stop the handling of new concession applications until a new and more robust concession framework was in place. Such new legal framework for the handling of wind power concession applications was adopted in June 2023, allowing for new projects to be promoted. However, the expectation is that new projects will not be ready for construction for a few years and that significant capacity increases will not be available before 2030.

Amendments to the Energy Act for smaller grid companies

The Norwegian Government has put forth amendments to the Energy Act, aiming to ease the functional separation requirements for smaller grid companies. This requirement will now only apply to grid companies with 100,000 or more customers, aligned with requirements set out in the EU Electricity Market Directive. Before the recent amendments, the Energy Act mandated a functional separation between network operations and other business activities for grid companies with over 10,000 customers. The corporate separation requirement between network operations and other business activities will remain in place for all grid companies.

As of January 2023, there are 89 grid companies in Norway, with 83 having fewer than 100,000 customers. The proposed amendments, which took effect on 1 July 2023, will result in less intrusive regulation for the 83 companies with fewer than 100,000 customers.

Judicial decisions, court judgments, results of public enquiries

There have been no major judicial decisions or judgments in the last 12 months that are directly relevant for the Norwegian energy sector. However, an ongoing dilemma regarding a decision from 2021 has resurfaced, commonly referred to as the *Fosen* case.

In October 2021, the Grand Chamber of the Norwegian Supreme Court unanimously declared the licences for the two largest wind farm developments in Norway invalid. The Supreme Court's decision was based on the finding that the wind farms' encroachment on inaccessible winter grazing areas violated the cultural rights of the reindeer-herding Sami community. According to Article 27 of the International Covenant on Civil and Political Rights (ICCPR), the rights of ethnic, religious, and linguistic minorities to enjoy their own culture must be protected. The court determined that the wind farms' impact on the Sami community's traditional reindeer-herding practices constituted a breach of this international obligation.

The appellate court had previously awarded compensation for winter feeding in enclosures as a means of mitigating the wind farms' impact on the Sami community. However, the Supreme Court found that this compensation was too uncertain to be considered an adequate remedy.

At the time of the Supreme Court's judgment, the wind farms in question had already been constructed and were operational. This presents a complex dilemma for both the energy sector and the Norwegian Government, as they must now determine how to remediate the situation in a manner that respects the court's decision and the rights of the Sami community.

The wind farms at Fosen continue to operate, raising questions about the appropriate course of action to address the Supreme Court's ruling. This ongoing dilemma underscores the need for a more comprehensive approach to balancing the interests of renewable energy development with the protection of indigenous rights. It highlights the importance of respecting the cultural rights of indigenous communities and the need for more robust measures to mitigate the potential negative effects of renewable energy projects. The decision also serves as a reminder of the importance of conducting thorough environmental and social impact assessments before embarking on large-scale energy projects.

As Norway and other countries continue to pursue renewable energy development, it is crucial to strike a balance between the benefits of clean energy and the protection of indigenous rights and the environment.

* * *

Endnotes

1. 11562: Energy commodity balance. Supply and use of different energy products 1990–2022. Statbank Norway (https://www.ssb.no/en/statbank/table/11562).
2. Energy – NVE (https://www.nve.no/energy).
3. Energy – NVE (https://www.nve.no/energy).
4. https://offshorenorge.no/contentassets/9d81e5bb138342de9d7dfd0d0c6b427b/blatt-hydrogens-rolle-i-utviklingen-av-norsk-sokkel.pdf
5. Equinor and German energy major RWE to cooperate on energy security and decarbonisation – Equinor (https://offshorenorge.no/contentassets/9d81e5bb138342de9d7dfd0d0c6b427b/blatt-hydrogens-rolle-i-utviklingen-av-norsk-sokkel.pdf).

Margrethe Antonsen Lilleng
Tel: +47 95 80 83 52 / Email: marl@wiersholm.no
Margrethe Antonsen Lilleng is an associate at the Wiersholm law firm in Oslo. Her primary responsibilities involve providing advisory services and managing transactions within the energy sector, with knowledge in offshore wind energy, hybrid cables, and ocean grid systems.

Jon Rabben
Tel: +47 95 21 01 64 / Email: jora@wiersholm.no
Jon Rabben is a partner at the Wiersholm law firm in Oslo. He works with acquisitions, financing, contract negotiations, dispute resolution, and regulatory issues. His advisory services are particularly aimed at Norwegian and international clients within the energy sector. His practice includes assistance to operations on the Norwegian continental shelf as well as traditional hydroelectric operations and new renewable energy sources. He has the right to appear before the Supreme Court. Among the recognised ranking agencies *Chambers and Partners* and *The Legal 500*, Jon is ranked as one of Norway's leading experts in renewable energy and petroleum law.

Wiersholm AS

Dokkveien 1 0250 Oslo, Norway
Tel: +47 210 210 00 / URL: www.wiersholm.no

South Africa

Margo-Ann Werner, Alecia Pienaar, Jackwell Feris & Megan Rodgers
Cliffe Dekker Hofmeyr Inc.

Overview of the current energy mix, and the place in the market of different energy sources

South Africa's energy mix currently comprises a broad range of both renewable and non-renewable energy sources, namely coal, nuclear, hydro, solar, onshore wind, concentrate solar, gas, diesel, biomass and landfill. Coal has historically been, and remains, the predominant energy source, with the Department of Mineral Resources and Energy (DMRE) stating that over 77% of the country's current energy supply is generated by its national utility's (Eskom SOC Ltd (Eskom)) fleet of coal-fired power stations.

Aligned with the global drive to decarbonise, South Africa's energy sector is undergoing significant reform in terms of which it will gradually transition to a low-carbon economy that will see increased reliance on cleaner and more sustainable energy supply resources.

The Integrated Resource Plan 2019 (IRP2019), which provides a blueprint for the country's energy mix, envisages the following to be achieved by 2030:

- decommissioning of 24,100 MW of coal power;
- 1,500 MW of new additional capacity from coal;
- 3,000 MW of new additional capacity from oil and gas;
- 22,900 MW of new additional capacity from renewable sources, including hydro, solar PV and wind;
- 2,088 MW of new additional capacity from storage; and
- 4,000 MW from other distributed generation (small-scale), co-generation, biomass and landfill technologies.

The IRP2019 is in the process of being revised, with changes to the above to be anticipated in light of current market developments and challenges as discussed below.

Changes in the energy situation in the last 12 months that are likely to have an impact on future direction or policy

Security of supply

Owing to the failure to adequately maintain the existing coal generation fleet and timeously bring new generation online, South Africa is facing an ongoing power crisis where there is insufficient electricity supply to meet demand. As a result, Eskom needs to implement load reduction demand-side management measures to alleviate strain on the grid and protect South Africa from a national blackout. This includes both load curtailment and load-shedding, the latter of which is composed of a process whereby Eskom manages demand by temporarily limiting distribution of energy to identified areas on a rotational basis.

While there has been intermittent implementation of load-shedding since 2007, it has reached unprecedented levels in 2023, with a combined total of 1,286 hours of load-shedding implemented this year so far. According to the South African Reserve Bank, load-shedding has significantly affected the country's GDP growth for the past two years. The most significant driver for change in policy and regulation in the electricity market is therefore the need to restore security of supply.

Grid constraints

The increasing gap between supply and demand has also been exacerbated by the lack of sufficient grid capacity to connect new generation projects, which has especially impacted the procurement of renewable energy in both the public and private sectors. In the latest round of the public Renewable Energy Independent Power Producer Procurement Programme (REIPPPP), only 1,000 MW out of a total of 4.2 GW was awarded to independent power producers (IPPs) owing to grid constraints. Several developed projects are also unable to be bid in private procurement programmes where Commercial and Industrial (C&I) offtakers are looking to secure renewable energy supply through bilateral wheeling arrangements.

Recent estimates indicate that R235 billion is required to upgrade the national grid, including the construction of new transmission lines and installation of additional transformer capacity. Owing to its existing debt burden, Eskom is unable to secure financing for the purposes of upgrading the national grid. Unlocking the grid will require significant governmental, policy and regulatory intervention, as it necessitates the restructuring of Eskom, access to alternative funding mechanisms and private sector involvement.

Reforming energy market

South Africa's electricity sector is founded on a vertically integrated market model in terms of which Eskom is responsible for electricity generation, transmission and distribution. Its monopolistic control of the market has, however, resulted in significant challenges that have ultimately led to the need to reform the entire industry. As per the Roadmap for Eskom in a Reformed Electricity Supply Industry (RERESI), "*Eskom has suffered severe damage as a result of governance and operational misdemeanours….this has had serious developmental and transformation consequences for governance and leadership within the entity, its constrained operations, its finances and its structure*". The RERESI identifies certain key steps for implementation of the reform, including the establishment of a separate subsidiary for transmission within Eskom.

Although reform of the market and unbundling of Eskom has long been on the agenda, it has finally gained significant traction over the last 12 months and will continue to be a key driver for change in terms of the policy and legal landscape.

Developments in government policy/strategy/approach

IRP2019 achievements and revisions

As noted, the IRP2019 lays the groundwork for electricity infrastructure planning up until 2030, with specific targets set for new generation from various energy sources and decommissioning of the coal-fired power stations. To date, there have been significant delays in achieving these targets, which has largely been exacerbated by the electricity supply crisis and lack of grid capacity.

With insufficient supply to meet demand, the Minister of Electricity is proposing the extension of life of some of Eskom's coal power plants as a means to ease load-shedding and support economic growth in the shorter term. This could, however, jeopardise South Africa's position within the Just Energy Transition Partnership (JETP) and the ability to attract financing to implement.

According to a report recently published by the National Energy Regulator of South Africa (NERSA), the DMRE has since 2012 procured a total 9,881 MW of renewable energy across nine separate renewable energy procurement bid windows, with only 6,149 MW in commercial operation. In addition, 1,684 MW of renewable energy was procured as part of the emergency Risk Mitigation IPP Procurement Programme (RMIPPPP) in 2020. More recently, and since publication of the IRP2019, 2,583 MW was awarded to renewable energy projects under Round 5 of REIPPPP, with the majority not having reached financial close as yet. As noted, owing to grid constraints, only 1,000 MW of 5.2 GW was awarded under Round 6 of REIPPPP, with all projects still working towards financial close. While Round 7 of REIPPPP was expected to be launched in June 2023, the bid window was yet to be opened in mid-October 2023. The South African Renewable Energy Master Plan (SAREM) (discussed below) recognises the "stop-start" and haphazard implementation of renewable energy procurement that has undermined the REIPPPP over the years.

Due to administrative and legal challenges, the DMRE has been unable to successfully implement new generation coal, oil and gas, and nuclear IPP procurement programmes.

As noted, the IRP2019 is currently being updated, with publication of a revised draft overdue since March 2023.

<u>Energy Action Plan</u>

In his State of the Nation Address (SONA) from July 2022, President Cyril Ramaphosa announced an Energy Action Plan composed of key governmental interventions to address the electricity crisis, namely:

- Fixing Eskom and improving the availability of existing supply.
- Enabling and accelerating private investment in generation capacity.
- Accelerating procurement of new capacity from renewables, gas and battery storage.
- Unleashing businesses and households to invest in rooftop solar.
- Fundamentally transforming the electricity sector to achieve long-term energy security.

To this end, the National Energy Crisis Committee of Ministers (NECOM) was established to oversee implementation of the proposed interventions.

Building on the Energy Action Plan, the President introduced additional measures at SONA 2023 to address load-shedding, including: declaration of a national state of disaster (which was terminated two months later); appointment of a Minister of Electricity; adjustments to the energy bounce-back loan scheme; investment in transmission infrastructure; and resolving Eskom's R400 billion debt burden.

The most recent update on implementation of the Energy Action Plan from August 2023 reflects key achievements made over the last 12 months, some of which are addressed in more detail elsewhere in this chapter.

<u>Just energy transition</u>

South Africa is a signatory to the Paris Agreement, with its first and updated Nationally Determined Contribution (NDC) committing to a peak, plateau and decline greenhouse gas (GHG) emissions trajectory between 2025 and 2030. Taking into account the country's systemic socio-economic challenges, the NDC has always echoed the IRP2019 in recognising that a "*just transition is at the core of implementing climate action in South Africa*", for which international cooperation and support will be fundamental.

A just transition contemplates a "no-one gets left behind" approach, where decarbonisation efforts cannot be prioritised to the detriment of socio-economic imperatives. The move away from a coal-based economy will therefore be gradual, taking into account the need to address poverty, unemployment and inequality.

In November 2022, President Cyril Ramaphosa released the Just Energy Transition Investment Plan (JET IP) for the period 2023–2027, which will give effect to the JETP formed at COP26 between South Africa, France, Germany, the United Kingdom, the United States and the European Union (collectively, the International Partner Group or IPG). According to reports, a JET IP implementation plan is currently in the works, with a draft anticipated to be released soon.

To date, South Africa has received USD11.9 billion in pledges from the IPG in support of the just transition, with the JET IP to drive the direction of the sector through the allocation of such funds to identified priority action areas.

Green hydrogen

Following approval of the Hydrogen Society Roadmap for South Africa (HSRSA) by Cabinet in October 2021, support for development of the green hydrogen economy has gained significant traction in South Africa, with widespread acceptance that it will be the key strategic driver for sustainable economic growth. As provided in the JET IP, "*it can enable the transition of a carbon-based and international trade-exposed sectors, protect the competitiveness of downstream industries, allow and enhance exports, boost GDP, support domestic decarbonisation and create jobs*".

At the request of Cabinet, the Department of Trade and Industry developed the draft Green Hydrogen Commercial Strategy (draft GHCS), which is intended to put the HSRSA in motion for development of South Africa's green hydrogen economic and industrial sector. The draft GHCS was released for comment in December 2022 and provides that government can undertake the following in promoting investment in domestic green hydrogen:

- incentives including subsidies, taxes and levies, as well as accelerated depreciation on capital equipment (both supply and demand side incentives could be used to drive cost reductions in the long term and enable a just transition, which will enable energy supply, sustainability and stability);
- carbon subsidies by using carbon taxes to subsidise green hydrogen production;
- preferential funding to provide low-cost funding through state-owned development finance institutions, incentivise private sector institutions to fund green hydrogen projects at preferential interest rates and seek preferential funding terms from global private sector and development finance institutions; and
- government-to-government arrangements that acknowledge that import countries will be looking for energy security and export countries for market share, which could allow for preferential arrangements such as long-term supply agreements.

The GHCS was approved by Cabinet on 10 October 2023, although a copy of the final Strategy was not made available to the public.

South Africa's Green Hydrogen Programme currently comprises 19 proposed green hydrogen projects identified for development, with an estimated R300 billion investment pipeline. Right before the launch of the GHCS, the then Minister of Public Works and Infrastructure formally gazetted nine of these projects as strategic integrated projects (SIP) to allow for priority investment and expediated development.

In June 2023, heads of agreement were concluded to launch a new USD1 billion green hydrogen fund SA-H_2, which is to be utilised to accelerate development of green hydrogen infrastructure across South Africa, including the nine SIP projects. A memorandum of corporation was also entered into between South Africa and Japan in September 2023 in terms of which Japan agreed to transfer critical technology and skills in support of South Africa's hydrogen economy.

South African Renewable Energy Masterplan

In recognition of the rapid increase in the rollout of renewable energy and storage technologies globally and the opportunities it presents in South Africa, the DMRE published the draft SAREM for comment in July 2023. The vision, objectives and pillars of the SAREM align with South Africa's sustainability needs, which aim to foster industrial and inclusive socio-economic development as part of a broader decarbonisation trajectory. The SAREM lists the following as the key objectives to reach by 2030:

- Grow the economy by fostering the rollout of renewable energy and battery storage projects.
- Grow the industry capacity in the renewable energy and battery storage value chain.
- Create and sustain decent employment across the value chain.
- Build the capabilities needed for the industry.
- Build a transformed industry throughout the value chain.
- Contribute to a just energy transition.

The SAREM sets out numerous catalytic and supportive interventions that will drive the above objectives to ultimately achieve the vision of the "*industrialisation of the renewable energy value chain to enable inclusive participation in the energy transition, serving the needs of society, and contributing to economic revival*".

Energy storage

In recognising the "complementary relationship" between smart grids, energy storage and non-dispatchable renewable energy technologies based on wind and solar PV, the IRP2019 provides for 2,601 MW of energy storage to be procured by 2030.

Since the IRP2019's publication, the importance of battery energy storage systems (BESS) to the South African energy mix has become more prevalent considering the ongoing energy crisis. According to a report released by the International Institute for Sustainable Development in June 2023, BESS has the potential to ease load-shedding given its ability to better balance electricity supply and demand and improve grid stability.

The first round of the Battery Energy Storage IPP Procurement Programme (BESIPPPP) was formally launched by the DMRE in March 2023 for the procurement of 513 MW of new generation at five specified Eskom-operated substations. All five sites are located in the Northern Cape Province, and it is understood that the energy storage capacity will assist in adding new generation capacity while managing grid constraints in the area. Preferred bidder announcement for the BESIPPPP was expected in early November 2023.

Developments in legislation or regulation

Electricity Regulation Act Amendments

South Africa's electricity supply industry is regulated in terms of the Electricity Regulation Act 4 of 2006 (ERA), which provides for the licensing of generation, transmission, distribution, reticulation, trading, import and export of electricity. Schedule II of the ERA provides for activities that are exempt from licensing requirements and required to follow a less onerous registration process.

Since its promulgation in 2006, the ERA was implemented in a manner that preserved Eskom's monopolistic control of the electricity supply market, largely to the exclusion of the private sector's participation. IPPs were only capable of penetrating the market through the government-led IPP procurement programmes, in terms of which Eskom was designated as buyer.

With significant delays in bringing new generation online and it becoming evident that the electricity supply gap would continue to increase under Eskom, Schedule II of the ERA was amended in June 2021 to lift the licensing threshold for energy generation projects to 100 MW and allow for wheeling of such energy to one or more customers. This unlocked a deep pipeline of investments in the renewable energy market, as private offtakers were for the first time able to conclude corporate purchase agreements with IPPs for the supply of renewable energy by way of wheeling arrangements. With the electricity crisis nevertheless worsening, the generation licensing threshold was deleted in its entirety in December 2023, with all generation projects only requiring registration. The Energy Action Plan implementation update from August 2023 describes this as "a game-changing reform [enabling] private investment in generation projects of any size", with the number of private sector generation projects having increased to over 100, representing more than 10,000 MW of new capacity.

<u>ERA Bill and unbundling of Eskom</u>

The Electricity Regulation Amendment Bill (ERA Bill) is the key proposed regulatory instrument for reform of the electricity sector. As noted, Eskom has historically been responsible for generation, transmission and distribution. Aligned with what is envisaged in the RERESI, the ERA Bill proposes to amend the ERA to provide for the establishment, duties, powers and function of a Transmission System Operator SOC Ltd (TSO). The ERA Bill further envisages to introduce a more competitive multi-market system that will, amongst other things, allow for competitive electricity trading.

The ERA Bill was formally tabled in Parliament at the end of August 2023 and is currently subject to public consultation processes, with some concerns over whether it will be possible to timeously progress the Bill before the 2024 elections. Failure to finalise the ERA Bill at the end of this Parliament's term would result in it having to be revived.

Certain steps have nevertheless been taken to lay the necessary groundwork for the market transition. The TSO has been incorporated and issued with licences in terms of the ERA to transmit, import, export and trade with electricity. Remaining conditions to the Eskom unbundling process include lender consent for reallocation of existing debt and establishment of an independent board for the TSO.

<u>Interim Grid Capacity Allocation Rules</u>

As noted, one of the most pressing challenges impacting the South African energy market is the lack of sufficient grid capacity to allow new generation projects to connect. With a deep pipeline of developed projects looking to secure access to connect to the national grid, the grid capacity allocation process had to be revised to better regulate what had become a highly competitive environment. This was especially evident following the failure to procure the majority of the new generation capacity available under Round 6 of REIPPPP.

Traditionally, Eskom would allocate grid capacity and issue a budget quote (BQ) on a "first come, first served" basis, processing applications in the order in which they were submitted. In June 2023, Eskom released the Interim Grid Capacity Allocation Rules (IGCARs), which introduced a revised grid access queuing system that operates on the principle of "first ready, first served" in terms of which shovel-ready generation projects receive priority. This system requires projects to progress their development status and incur additional costs at risk, without any guarantee of being allocated grid capacity.

Further, generation projects that submitted BQ applications under the previous "first come, first served" regime and progressed on the understanding that they would be able to secure a grid connection were impacted. This resulted in a legal challenge being brought against the IGCARs, as discussed below.

Climate Change Bill

The Climate Change Bill (CCB) represents South Africa's dedicated legal response to climate change, and will, once promulgated, be a key framework piece of legislation and tool for implementation of its commitments under the Paris Agreement. To allow for a long-term, just transition to a low-carbon and climate-resilient economy, the CCB provides for, *inter alia*:

- establishment of administrative bodies to coordinate and monitor the climate change response, including provincial and municipal forums on climate change and a Presidential Climate Commission;
- development and adoption of climate change adaptation plans at national and sectoral levels;
- a national GHG emissions trajectory and sectorial emissions targets;
- allocation of carbon budgets and prescribed requirements for associated GHG emission plans by persons with an allocated carbon budget; and
- phasing-down and phasing-out of synthetic GHG emissions.

In terms of process, the CCB was introduced in Parliament in February 2022, with several public hearings held between September 2022 and May 2023. Following deliberation of public submissions and required amendments, the CCB was finalised and adopted by the Parliamentary Portfolio Committee on 20 September 2023. Most recently, the CCB was passed by the National Assembly on 24 October 2023, and will now be sent to the National Council of Provinces for concurrence, before it can be assented to by the President. Considering its extensive resource requirements from a capacity, skill and monetary perspective, especially at provincial and municipal level, implementation of the CCB will have to be gradual, while still taking into account South Africa's obligations under the Paris Agreement.

Revised bounce-back loan scheme

Following announcements made during the 2023 SONA and the 2023 Budget Speech, the National Treasury issued the Energy Bounce Back (EBB) Loan Guarantee Scheme on 8 August 2023 in terms of which the government hopes to incentivise generation of 1,000 MW of electricity through rooftop solar PV systems by 30 August 2024. As per the EBB, "*to facilitate these investments, government through a government guarantee administered through the South African Reserve Bank, assume the initial losses (20%) with finance providers assuming the risk of the remaining losses for SMEs and households' rooftop photovoltaic solar investments*".

The EBB will be implemented through the following mechanisms:

- Loan guarantee for rooftop solar systems for small and medium-sized enterprises (SMEs) and households, inclusive of batteries, inverters and other installation-related costs.
- Loan guarantee for rooftop solar for Energy Service Companies (ESCO) providing leasing, instalment sales and power purchase contracts to SMEs and households, thereby enabling them to secure a renewable energy supply solution without being liable to finance the costs upfront.
- Working capital loans to rooftop solar supply companies to increase installation of solar solutions through access to solar equipment within reduced timeframes.

Additional financing mechanisms are also being developed by the National Treasury in corporation with the Industrial Development Corporation of South Africa to further improve ESCO's competitive edge in the market.

Nuclear Regulator Amendment Bill

Nuclear energy is no stranger to South Africa as it already forms part of its current energy mix. The nuclear activities in South Africa are regulated by the National Nuclear Regulator (NRR), which was established in terms of the National Nuclear Regulator Act 47 of 1999 (NRR Act). The NRR is responsible for, amongst other things, issuing nuclear authorisation for construction and operation of any nuclear installation and the protection of persons, property and the environment from the harmful effects of nuclear damage.

The NRR has not been amended since its inception. However, the process of amending the NRR Act is on the cards. In July 2023, a National Nuclear Regulator Amendment Bill (NRR Amendment Bill) published a notice indicating the intention of the Minister to introduce the NRR Amendment Bill in the National Assembly. The Nuclear Regulator Amendment Bill seeks to amend the NRR Act and address the existing gaps by, *inter alia*, providing the NRR and inspectors with additional powers as well as for administrative penalties as an alternative to criminal sanction. The amendment also seeks financial provision for costs associated with safe rehabilitation or decommissioning of nuclear facilities. The intended amendments will also assist with aligning the NNR Act with the International Atomic Energy Agency (IAEA) prescripts and its best practice. South Africa is a member of IAEA and a signatory to the Convention on Nuclear Safety, particularly since the IRP2019 still recognises the role of nuclear energy in South Africa's plans to ensure the supply of energy security while simultaneously responding to the challenges of climate change and socio-economic development. In that regard, the DMRE has communicated its plans to issue a request for proposals for 2,500 MW worth of new nuclear energy projects by 2024, with the President of South Africa recently indicating the possibility that nuclear will be included in the anticipated updated IRP.

Upstream Petroleum Resources Development Bill

The Upstream Petroleum Resources Development Bill (Upstream Bill) will significantly change the legislative framework of the oil and gas sector. Currently, the Mineral Petroleum Resources Development Act (MPRDA) regulates both the mining sector and the upstream petroleum exploration and production sector.

The current iteration of the Upstream Bill seeks to create and enable an environment for the acceleration of exploration and production of South Africa's oil and gas resources by separating upstream oil and gas operations from mining operations. This separation allows the emerging and nuanced upstream oil and gas sector to be regulated entirely separately from the more established mining sector.

Some of the salient provisions of the Upstream Bill include:

- Petroleum right – under the MPRDA, two separate rights are granted for exploration and production. This will change under the Upstream Bill, which introduces a petroleum right that will govern the key terms of both the exploration phase and the production phase, with the duration thereof depending on the location and status of the acreage.
- Black participation – the Upstream Bill prescribes a minimum of 10% black participation in every petroleum right.
- State participation – the Upstream Bill also requires a 20% state participation in every petroleum right.

The Upstream Bill was introduced in Parliament on 1 July 2021 and was subjected to two phases of public participation. The written submissions leg of the procedure began on 28 June 2022 and ended on 29 July 2022 while the public hearings commenced in the Western Cape on 17 February 2023 and ended in Gauteng on 28 May 2023. The Upstream Bill will now be reconsidered by the National Assembly, which will debate and vote on the passing of the bill with or without amendments. As with the CCB, the Upstream Bill will then be sent to the National Council of Provinces for concurrence, before it can be assented to by the President.

Streamlining permitting

Various regulatory interventions have been introduced to streamline permitting in the energy sector, especially in respect of renewable energy projects. The removal of regulatory red tape is aimed at expediting development of these projects to ensure that new generation capacity is brought online as soon as possible. As summarised in the August 2023 progress update to the Energy Action Plan, the following changes have been implemented:

- dispensing with the need for an environmental authorisation (EA) in terms of the National Environmental Management Act 107 of 1998 and 2014 Environmental Impact Assessment Regulations for transmission infrastructure located in areas of low or medium environmental sensitivity. A draft Solar Photovoltaic Exclusion Norm is also currently being developed by the Department of Forestry, Fisheries and the Environment (DFFE), which will allow for such exclusion in relation to the development or expansion of solar PV facilities;
- expedited application timeframes for various permitting processes, including applications for EAs for SIP projects, registration with NERSA for generation projects, grid connections with Eskom, and land-use authorisations; and
- the Minister of Trade, Industry and Competition launched the Energy One-Stop Shop (EOSS) in July 2023. The intention of the EOSS is to expedite the multitude of regulatory permitting approval processes that apply to energy projects. The EOSS will be rolled out across four phases, with the first phase already operational to allow for projects to register.

Judicial decisions, court judgments, results of public enquiries

Challenges against proposed gas-to-power facilities

Several gas-to-power facilities have been developed, including acquiring associated environmental licences. Many of these proposed projects had been bid as part of South Africa’s expedited power procurement process under the RMIPPPP. The projects have, however, been subject to significant legal challenge by public and environmental groups who have strategically challenged the environmental permits of these projects and that, allegedly, climate change impacts had not been properly assessed and that the public participation process was flawed. One such legal challenge was against the grant of an EA to Eskom, by the DFFE, for the proposed 3000 MW gas-to-power plant to be developed in Richards Bay, KwaZulu-Natal. The Pretoria High Court dismissed the review application launched by the applicants, upholding Eskom’s EA. Another legal challenge was launched by the same environmental interest groups against the proposed 400 MW Richards Bay Gas to Power Plant. In this matter, the interest groups brought a judicial review application against the grant of an amendment to the EA of this project, on the basis that the amendment required that a climate change impact assessment should have been done. The Pretoria High Court also dismissed this application due to the applicants being out of the 180-day period in which to launch the review and insufficient reasons why condonation should be granted.

This outcome was also significant as the interest groups were directed to pay the costs of the project company developing the project, an order not generally made against non-profit and non-governmental organisations. In both matters, the interest groups have appealed the judgments. These challenges are significant as they will go towards determining whether the baseload capacity offered by gas-to-power facilities will be realised, or, similar to what occurred in respect of the challenges to proposed new coal-to-power plants, these gas projects will be abandoned by developers and investors due to ongoing legal challenges.

IGCAR challenge

Owing to the onerous consequences of the IGCARs, two project companies and their IPP developer, G7 Renewable Energies (Pty) Ltd, brought a two-part legal challenge in the High Court: (i) for an interim interdict against implementation of the Rules; and (ii) to have the IGCARs reviewed and set aside in terms of the Promotion of Access to Justice Act 3 of 2002 for being unlawful, irrational and unfair. The High Court dismissed the interdict application, finding that the IGCARs were necessary in light of managing grid access amidst the energy supply crisis. Following industry engagement and relaxation of some grid access criteria, the review application was also ultimately withdrawn. Applications for allocation of grid capacity will therefore continue to be managed in terms of the IGCARs for the foreseeable future.

Margo-Ann Werner
Tel: +27 11 562 1560 / Email: Margo-Ann.Werner@cdhlegal.com
Margo-Ann Werner is a Director in the Environmental Practice of the Corporate and Commercial department. Margo started her career at Fasken as a Candidate Attorney in 2013 where she was appointed as an Associate in 2015 and promoted to Senior Associate in 2018. Margo joined Cliffe Dekker Hofmeyr as a Senior Associate in March 2020 and was promoted to Director in April 2021. Margo has extensive experience in respect of environmental, mining and energy regulatory considerations and has worked on numerous projects and matters relating to electricity infrastructure development across several rounds of the South African Renewable Energy Independent Power Producer Procurement Programme.

Alecia Pienaar
Tel: +27 21 481 6343 / Email: Alecia.Pienaar@cdhlegal.com
Alecia Pienaar was recently appointed as Counsel within the Corporate and Commercial department advising on environmental, energy, mining and other regulatory laws, forming a key part of a number of cross-disciplinary teams within the firm. She has extensive experience advising on the environmental permitting and management obligations of energy projects, including solar, wind, hydro, nuclear, thermal and LPG. Prior to her appointment as Counsel, Alecia was employed within the private markets team at a leading IPP, where her primary focus was managing and assisting with utility-scale C&I projects across development, bidding and financial close processes.

Jackwell Feris
Tel: +27 11 562 1825 / Email: Jackwell.Feris@cdhlegal.com
Jackwell Feris has over 15 years' experience in the oil and gas, mining and minerals, energy and power, infrastructure and transport, government and state-owned sectors, having represented governments, state-owned entities and private commercial parties and investors in complex disputes providing dispute prevention, dispute avoidance and dispute resolution services and providing advisory work on projects and/or transactional matters. He has developed a depth of skills and experience in oil and gas laws, energy laws, mining laws, constitutional and general public law matters, public procurement and public finance law, and international arbitration law, among others.

Megan Rodgers
Tel: +27 21 481 6429 / Email: Megan.Rodgers@cdhlegal.com
Megan Rodgers has assisted clients with oil and gas projects in more than 14 countries across five continents. She has worked closely with independent oil companies (IOCs), national oil companies (NOCs), service providers to the oil and gas industry and regulatory authorities. She provides commercial, regulatory and advisory legal services to the upstream, midstream and downstream oil and gas sectors. She specialises in upstream M&A and has advised on farm-ins and participating agreements, joint operating agreements, project development agreements and gas sales agreements.

Cliffe Dekker Hofmeyr Inc.

1 Protea Place, Sandton, South Africa
Tel: +27 11 562 1000 / URL: www.cliffedekkerhofmeyr.com

United Kingdom

Michael Burns, Antony Skinner & Justyna Bremen
Ashurst LLP

Overview of the current energy mix, and the place in the market of different energy sources

As discussed in the last edition of this chapter, the UK's energy mix and energy policy has been shaped by the political and economic events of the past few years, notably the conflict in Ukraine. In the last year, we have seen greater refinement and sophistication in the policies adopted by government in response to such events. As nations across the world adapt to increased price inflation and cuts to supply, we are beginning to see greater focus being placed on energy security in addition to a drive towards Net Zero, which will inevitably influence the UK's energy mix going forward.

Before looking to the future, it is pertinent to consider the UK's energy mix in 2022. In the 2023 edition of this chapter, we discussed the impact of capacity limitations on the UK's ability to produce energy in the North Sea, in addition to the issues caused by unfavourable weather conditions to renewable power generation. These issues did not manifest in 2022, though energy consumption in the UK has remained low: 0.9 per cent down on 2021, largely due to increasing prices and warmer weather conditions resulting in decreased demand from end users.

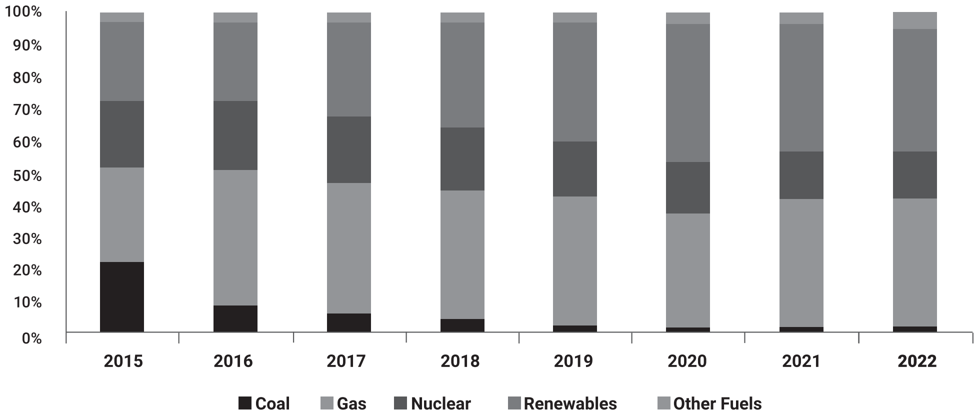
Turning to electricity generation, the proportion of energy generated from renewable sources in the UK rose to record highs in 2022, accounting for 41.5 per cent of total generation. Notably, the share of electricity generated from renewable sources exceeded the share from fossil fuels (40.8 per cent) for only the second time on record. This was partly driven by increases in renewable capacity, with wind generation capacity up 12 per cent (12.4 GW) and solar capacity up 5.3 per cent (2.5 GW). Offshore wind in particular drove growth in wind capacity, with 0.9 GW being added to Moray East and 1.4 GW added to Hornsea Wind Farm alone. More favourable weather conditions also facilitated greater output from renewable sources, with average wind speeds sitting at 0.7 knots higher than in 2021 and average sun hours increasing by 0.8 in the same time period. Bioenergy was the only renewable source to suffer a fall in its share of generation, primarily caused by outages at key bioenergy sites.

Nuclear output fell by 0.2 per cent against 2021 levels despite a 4.6 per cent increase in nuclear-derived electricity generation. This was attributable to reductions in capacity driven by the closure of two nuclear power plants, Hunterston B and Hinkley Point B, in 2022.

Coal generation has also continued to fall, with output down to the second-lowest value on record. Only four coal-powered power plants remained in operation in 2022, reflecting the government's commitment to phasing out coal-fired power plants by October 2024. Fossil fuel generation as a whole, however, increased by 0.9 per cent, with gas generation up 1.5 per cent.

See figure 1 for a breakdown of sources of electricity generation in the years 2015 to 2022.

Figure 1: Share of electricity generation in years 2015 to 2022[1]



UK energy production showed signs of recovery in 2022, being 3.1 per cent higher than the record lows of 2021. This followed the return to active operation of a number of North Sea terminals, including the Forties Pipeline System. Oil production, however, fell by 8 per cent to 38m tonnes. This can partly be ascribed to infrastructure maintenance over the summer, leading to the UK once again becoming a net importer of oils. Conversely, gas production increased by 16 per cent as the UK tripled its gas exports as against 2021. Due to low demand caused by rising energy costs, indigenous gas production accounted for 54 per cent of demand, up from 38 per cent of demand in 2021.

Imports of energy fell by 2.6 per cent, reducing the UK's net import dependency to 37.3 per cent of consumption in 2022, a fall from 37.9 per cent in 2021. This reduced net import dependency is, however, set against the backdrop of substantially increased imports. Imports of energy stood 11 per cent higher in 2022 than in 2021, with gas imports at record levels. Liquefied natural gas (LNG) imports in particular grew by 74 per cent, though much of this gas was subsequently exported to mainland Europe as the continent attempted to reduce its dependence on Russian gas. Oil and gas continued to form the bulk of the UK's energy imports at over 90 per cent of total imports, with oil coming primarily from the US, and Norway providing the largest share of imported gas.

Falls in domestic energy consumption (down 0.9 per cent on 2021), however, led to the UK becoming a net exporter of electricity for the first time in over 40 years with net exports of 5.3 TWh. Outages across the French nuclear network also spurred exports to France, which typically exports its own electricity to the UK.

Changes in the energy situation in the last 12 months that are likely to have an impact on future direction or policy

Continued focus on energy security

As reported in last year's edition of this chapter, the invasion of Ukraine by Russia marked a significant turning point for the UK's energy policy, with energy security becoming a key focus. For the first time in recent history, the UK has had to grapple with the fact that "security of supply" does not just mean ensuring that there is sufficient electricity generation capacity or a sufficient number of LNG receiving terminals, but that instead much greater emphasis is needed on the UK's ability to be self-sufficient, while at the same time implementing the UK's Net Zero objectives.

In April 2022, the government released an Energy Security Strategy, which expressed the aim of ensuring that there is "secure, clean and affordable British energy for the long term". Many of the elements of the strategy encompassed the things that already formed an integral part of the UK's energy policy, including decarbonisation technologies, energy efficiency and new build nuclear, and increasing the role of non-fossil fuel energy in sectors such as industry, heating and transport. As discussed later in this chapter, the UK government has continued to take forward many of these elements, with a continued commitment to clean hydrogen, carbon capture, usage and storage (CCUS), offshore wind, nuclear and domestic oil and gas production in particular. However, there have also been some new developments, reflecting the evolution of energy policy but also as a consequence of changes in political leadership. At the time of writing of last year's edition of this chapter, Liz Truss had taken over as the UK's Prime Minister. However, shortly after Truss's appointment, Rishi Sunak took over as the Prime Minister on 25 October 2022.

A major step taken by the new Prime Minister in February 2023 was the creation of a new government department solely focused on energy – the new Department for Energy Security and Net Zero – with the name of the department reflecting its dual remit. Building on the earlier Energy Security Strategy of 2022, the government then published the "Powering up Britain" energy security plan of March 2023. The "Powering up Britain" plan set out some new policies, intended to facilitate some of the existing elements of the UK's energy security policy, including the following:

- the establishment of a new body, Great British Nuclear (GBN), tasked with the responsibility of leading the delivery of the UK's new nuclear power programme;
- also in the nuclear space, a new competitive process to select the best small modular reactor (SMR) technologies;
- the launch of a Wind Manufacturing Investment Scheme, to provide up to £160 million to kick-start investment in port infrastructure projects;
- action plans to reduce the development time for electricity transmission network projects and accelerating electricity network connections;
- a new Great British Insulation Scheme to deliver £1 billion additional investment by March 2026 in household energy efficiency upgrades, such as loft and cavity wall insulation;
- planning reforms designed to streamline and accelerate the planning consent process, to shorten the time period for development of new renewable energy generation plants; and
- a new Biomass Strategy.

Some of these policy developments are discussed in more detail later in this chapter.

Developments in government policy/strategy/approach

Shale gas

The focus on domestic energy production meant that in September 2022, the government announced the lifting of a moratorium that had been placed on shale gas development in response to safety concerns relating to hydraulic fracturing. This decision to lift the moratorium was based on an earlier scientific review that had been commissioned by the government. However, the new Prime Minister Rishi Sunak reversed this decision shortly after taking office, meaning that the moratorium continues.

Oil and gas exploration and production in the North Sea

The North Sea Transition Authority (NSTA) opened the 33rd offshore licensing round on 7 October 2022. This was the first offshore licensing round to take place since the 32nd licensing round, which was launched in 2019. The 33rd licensing round attracted a total of 115 bids across 258 blocks and part-blocks, from a total of 76 companies.

This licensing round was the first one to take place since the introduction of the Climate Compatibility Checkpoint (CCC), which was introduced to ensure that licensing rounds are compatible with wider climate objectives in the future, including net-zero emissions by 2050.

The NSTA was originally just the upstream oil and gas regulator, but its remit has been extended to other North Sea technologies that are to play a key role in the UK's energy transition – low-carbon hydrogen, and CCUS in particular. The NSTA is the regulator that issues licences required for carbon dioxide storage sites. In 2022, the NSTA launched its first-ever carbon capture licensing round, which has culminated in the award in 2023 of 21 licences relating to depleted oil and gas reservoirs and saline aquifers.[2] It has also been announced that the NSTA will become the licensing/consenting authority for offshore hydrogen pipelines (similarly to oil and gas pipelines) and the licensing/consenting authority for offshore hydrogen storage, which will enable the NSTA to issue hydrogen storage licences.

Contracts for Difference – a change of approach?

In March 2023, the government launched the fifth allocation round (AR5) for Contracts for Difference (CfDs). Since 2013, CfDs have been the main mechanism for incentivising investment in renewable energy projects. AR5 was the first allocation round to take place since the government's renewed commitment to hold allocation rounds annually.

The previous allocation round, AR4, had been dominated by offshore wind, with 7 GW of capacity across five projects at a strike price of £37.35/MWh (strike prices were worked out on the basis of 2012's prices, now equal to £43.37/MWh). However, other technologies, such as tidal stream, floating offshore wind, and solar PV onshore wind, had also been awarded CfDs.

The outcome of AR5, on the other hand, was quite different: offshore wind did not feature at all in the list of projects that had been awarded CfDs, with the allocation round dominated by onshore wind and solar PV projects, as well as some tidal stream and geothermal projects, and one remote island wind project. When considered in the context of current electricity market conditions and the design of the CfD, perhaps this was not such a surprising result. The CfD regime has been designed as a price "top-up" for generators, with payments made to generators calculated as being the difference between a "reference price" (representing the market price) and a "strike price" (representing a price that makes a project economically viable). However, a key feature of the regime is also the fact that generators are required to make payments to the CfD counterparty if the reference price is higher than the strike price.

At a time when the cost of developing renewables was high, and power prices were relatively low, the CfD regime was attractive to all renewables generators. However, two things have happened since the CfD regime was introduced originally: the cost of developing most renewable energy projects (offshore wind in particular) has decreased; and power prices, which are currently linked to gas prices in the UK (due to the design of the electricity market), have been high. The high electricity prices mean that offshore wind projects that already hold CfDs are currently making payments back to the CfD counterparty (when the reference price is higher than their strike price), and CfDs have therefore become more of a price stabilisation mechanism, rather than a subsidy.

However, even as a price stabilisation mechanism, CfDs may have lost their appeal to offshore wind developers. Industry body Energy UK noted, in its analysis[3] of the design of AR5, that the strike price that had been set by the government for AR5 did not take into account the increased costs currently faced by offshore wind, resulting from "*a combination of inflation, interest rate increases pushing up financing costs, a supply chain crunch, and regulatory uncertainty through systemic problems with grid connections and planning*". In that same analysis, Energy UK predicted a shortfall in the amount of offshore wind capacity that the government was aiming to secure through AR5, stopping short of predicting the actual outcome.

The question arises as to what this means for the UK's target of 50 GW of offshore wind capacity by 2030, including up to 5 GW of floating wind. It seems likely that the government will take into consideration the results of AR5 when setting the parameters for AR6, due to take place in 2024. But could the offshore wind industry be ready to take the leap of faith towards subsidy-free offshore wind farms? This may seem like the obvious choice in the context of the current electricity market, but the difficulty for many developers is the fact that current high prices may not last, and also the government has been reviewing the structure of the electricity market (see discussion of REMA below). Nonetheless, it has been reported that BP has been considering investment in two subsidy-free offshore wind farms.[4]

<u>What next for offshore wind and CfDs?</u>

Offshore wind remains a core element of the UK's energy policy – not just to facilitate the transition from fossil fuel generation to renewables, but also to provide the renewable electricity required for other technologies, such as green hydrogen. For this reason, the government appointed an "Offshore Wind Champion", Tim Pick, to conduct an independent review of what is required to realise the UK's offshore wind ambitions. Tim Pick's role and remit has been seen to be somewhat akin to the 2014 review of the upstream oil and gas industry, carried out by Sir Ian Wood, which resulted in significant changes for the oil and gas industry.

In March 2023, Tim Pick published the "Seizing our Opportunities" report, outlining a series of recommendations. The recommendations cover a wide scope of issues, including:

- seabed leasing, in particular a recommendation that seabed leasing for offshore wind should operate within the context of a high-level strategic framework for the entire energy system;
- environmental and planning consenting reform and availability of data;
- grid constraints and the grid connection process, which are identified as being a barrier to all generation projects, not just offshore wind;
- CfDs, including a recommendation that potential new models could be explored; for example, the award of CfDs to projects at an earlier stage, before they have development consent, and a recommendation that non-price factors are introduced into the CfD auction process as an additional or alternative means of incentivising behavioural change;
- port infrastructure that can accommodate offshore wind development; and
- the role of innovation and skills.

The introduction of non-price factors into the CfD regime is one area that the government is already progressing. The government published a call for evidence on non-price factors in April 2023, and its response to the call for evidence in September 2023.[5] The call for evidence presented different models for how non-price factors – i.e. factors other than price – would be incorporated into the CfD regime. One model, for example, would introduce a "top-up" to the CfD strike price. Auctions would be run exactly as they are now, with no change to the bidding process, but after the auction has been run, projects that made it through the auction, and that submit and implement high-scoring, non-price factors, could receive a top-up to their CfD. The government has not yet made any decisions on the implementation of non-price factors.

Electricity transmission reform

Similarly to the appointment of Tim Pick to review offshore wind, the government also appointed an "Electricity Networks Commissioner", Nick Winser, to prepare recommendations on how to accelerate the delivery of UK electricity transmission infrastructure. Enhancements to the electricity transmission infrastructure are recognised as being essential to the UK's Net Zero objectives, given that a large proportion of decarbonisation relies on electrification, which will mean greater demands being placed on the transmission system.

The Electricity Networks Commissioner's report includes the following key recommendations to drastically reduce the amount of time it takes to develop new transmission infrastructure:

- the Future System Operator (FSO) (a new body being established under the Energy Act 2023) should be established quickly and be responsible for producing a Strategic Spatial Energy Plan (SSEP);
- the FSO, supported by the regulator Ofgem, should urgently assess the scope for new short-term and long-term regional flexibility markets;
- in the planning context, National Policy Statements should be updated urgently and regularly;
- a new document, Electricity Transmission Design Principles, should be created to detail the principles and methods used to design the system and decide the configuration of assets; onshore or offshore, overhead or underground;
- Ofgem should urgently conclude its Future Systems and Network Regulation consultation and establish a new regulatory arrangement for transmission network companies to incentivise the delivery of new infrastructure; and
- community engagement and benefit mechanisms need to recognise the impact of new infrastructure on the communities where the new infrastructure is situated, with clear guidelines for the establishment of community benefits.

Offshore Transmission Network Review

The government has concluded its Offshore Transmission Network Review. The review was launched in 2020, in response to growing concern that the developer-led approach, where offshore wind projects connected individually to the grid on a radial (point-to-point) basis, would present a barrier to realising the UK's offshore wind targets. One of the areas that was the focus of the review was the role of Multi-Purpose Interconnectors (MPIs). MPIs are subsea electricity cables that will be able to connect the UK's electricity system to those of neighbouring countries (the role played by existing interconnectors) but also connect offshore power generators – such as wind farms – to the shore (in the same way as offshore transmission cables are currently able to). At present, an interconnector licence is required under the Electricity Act 1989 to operate an interconnector, but MPIs will be a new asset class for which a new MPI licence will be required, following amendments being made to the Electricity Act 1989 under the Energy Act 2023.

In June 2023, Ofgem published a consultation[6] on the proposed regulatory regime to apply to pilot projects. This covers the licensing framework, regulatory regime, and network charging. The two pilot MPI projects that have been selected are the LionLink MPI, linking the UK to the Netherlands, and the Nautilus MPI, linking the UK to Belgium.

Grid connections reform

One of the key barriers to the development of new low-carbon generation has been the ability for projects to be able to connect to the distribution and transmission networks, with transmission network connections in particular often facing long lead times. Reforms to address this are being taken forward by both distribution network operators and the transmission system operator (NGESO).

NGESO is taking forward both short-term and long-term reforms. In the short term, NGESO has been implementing its "5-point plan". One of the initial reforms being implemented as part of this plan is the approach to connections for storage projects. NGESO is accelerating the connection of energy storage projects by removing the requirement for non-critical enabling works to be complete before they connect. This means that the only transmission works that storage projects will need to wait for are those that are essential to enabling a physical connection to the network (such as building a substation), those needed to mitigate fault-level issues or those needed to meet safety-based requirements. The trade-off, however, is that storage projects connecting under such conditions will be offered a non-firm connection, meaning that, in certain circumstances, such storage projects may have restrictions imposed on their output without compensation. Another key element of the "5-point plan" is allowing customers to leave the "connection queue", once they have applied for a connection, without incurring penalties for doing so.

For longer-term reform, NGESO is considering and consulting[7] on more radical proposals. For example, one option being considered (which is very different to current arrangements) would involve an annual application window, and within the window period, NGESO would work with the transmission asset owners to carry out a batched assessment of all accepted connection applications received within the window and develop an associated coordinated network design. NGESO said that it expected to publish its final recommendations and an implementation plan by November 2023.

Capacity Market

The National Grid Electricity System Operator, in its role as the Capacity Market (CM) Delivery Body, has continued to hold annual CM auctions to secure capacity under the CM regime. The T-4 (four-year ahead) capacity auction for delivery in 2026–27 concluded in February 2023 at a record price for a T-4 auction of £63/kW/year. This is the second-highest-ever price, after last year's T-1 (year ahead) auction cleared at £75/kW/year when the capacity target exceeded the amount of capacity participating in the auction.

In 2023, the government consulted[8] on some changes to the CM regime, which are to be implemented in two phases: phase 1 includes proposals to be implemented prior to the 2024 capacity auctions; and phase 2 includes proposals that are to be further developed and implemented at a later stage. The phase 1 proposals include:

- changes to the way in which connection capacity is determined, to ensure it better reflects export capability;
- changes to the timelines for calculating non-delivery penalties by amending the current 21-working-day deadline to allow up to 35 working days; and
- clarification of the auction clearing mechanics, to ensure that the legislation more clearly reflects policy intent and implementation.

The phase 2 proposals, which involve more substantive changes, include:

- a proposal to reorganise the Satisfactory Performance Days process around three distinct pass windows over the course of the winter of the Delivery Year;
- a proposal to strengthen the non-delivery penalty regime;

- proposals to reduce the emissions intensity limit applicable to new build plants from 1 October 2034;
- a proposal to enable low carbon capacity with low capital expenditure to access multi-year agreements of up to three years without being required to meet capital expenditure thresholds;
- a proposal to update the reference cost levels for the CM capital expenditure thresholds; and
- a proposal to introduce a new nine-year threshold as a mid-point between the existing three- and 15-year terms for capacity agreements.

Renewables Obligation – move to Fixed-Price Certificates

The Renewables Obligation (RO) regime is a green certificate scheme, which was the support mechanism for renewable energy projects until the introduction of CfDs. The RO regime is now closed to new projects; however, for projects already accredited under the RO regime, it will continue to operate until it is closed on 31 March 2037. Currently, generators accredited under the RO receive Renewables Obligation Certificates (ROCs) for the electricity that they generate, which they sell to suppliers. However, when the RO regime was closed to new projects, the government said that in the last 10 years of the scheme, from 2027, ROCs would be replaced with new "Fixed-Price Certificates" (FPCs). In July 2023, the government published a call for evidence[9] on possible models for implementing such an FPC scheme. The government has proposed two models, with some options within those models, as follows:

- a model involving a central counterparty that would be responsible for paying generators for the certificates they have earned and settling suppliers' obligations under the RO by collecting funds from suppliers to make payments to generators; and
- a model where the central counterparty would also purchase certificates from market participants at a fixed price, either quarterly or annually, but trading of FPCs would still be allowed (as it is for ROCs). Generators could either choose to hold their certificates and sell them to the central counterparty, or alternatively to sell them to suppliers (either directly or through traders) who would then sell them to the central counterparty.

Heat networks – a new regulatory regime

Pursuant to the provisions of the Energy Act 2023, the government is implementing a new regulatory structure for heat networks, which will be administered by the gas and electricity markets regulator, Ofgem. Two activities will fall within the scope of regulation: the operation of relevant heat networks (meaning district and communal heat networks); and the supply of heating, cooling or hot water to consumers through a relevant heat network. Once the new regime is fully implemented, operators of such networks and suppliers of heat will be required to apply to Ofgem for authorisation. One of the key drivers for the new regime is to protect the customers of heat networks, and the government is currently consulting[10] on the standards of conduct that will apply to heat network operators and heat suppliers.

CCUS

As discussed in previous editions of this chapter, the government has continued to take forward the new regulatory framework and business models developed to facilitate the development of CCUS in the UK. There are to be a number of transport and storage networks (T&S networks), with carbon dioxide emitters connected to these T&S networks, with both the T&S networks and the emitters being supported under revenue support contracts. Each such T&S network and the emitters who are to be connected to it are referred to as a "cluster". The first two such clusters that were selected through the "Track-1 process" were the HyNet Cluster and the East Coast Cluster. Most recently, the government announced in July 2023 that its "Track-2" process has resulted in two more prospective T&S networks being selected – the Acorn and Viking projects. The emitters who will become a part of these two new clusters have not yet been selected.

The regulatory regime needed to underpin the CCUS programme, including a new licensing regime for T&S networks, is set out in the Energy Act 2023.

Hydrogen

The UK government published its response to the August 2022 consultation on business model design, regulation, strategic planning and the role of blending in hydrogen transport and storage infrastructure in August 2023. The UK government's business model to support hydrogen transport infrastructure will initially focus support on the transport of hydrogen as a gas via large-scale onshore pipelines. The UK government's minded to position is that a regulated asset base (RAB) model will form the basis of the transport business model. This model has been applied to the energy and water sectors and will be used for CCUS carbon dioxide transport and storage business model. It is expected that the hydrogen transport RAB model will likely follow the natural gas RAB framework. In addition, the UK government has indicated that it is minded to provide further subsidies alongside the RAB model to avoid high upfront costs being imposed on initial hydrogen transport users. A broader policy decision on whether or not blending will be enabled by the UK government is subject to further consultation. A consultation was issued by the UK government in September 2023 relating to the assessment of the case for hydrogen blending and lead options for its implementation, if enabled.

In terms of hydrogen storage, the UK government has stated that it is minded to offer support to storage providers under a standalone business model to give confidence to investors that the storage facilities will generate sufficient revenue and enable providers to price competitively and attract users. In particular, the UK government is minded to implement a "revenue floor" business model. The floor would be equal to the total capital costs of developing the storage facility, plus fixed operational costs, plus some return on capital investment. This model is still subject to further development, and given the UK government's concerns of potential overcompensation, it may also include a gainshare mechanism or a cap and floor regime. Similar to the CfD model and the Low Carbon Hydrogen Agreement, the UK government's minded to position is for storage subsidy to be delivered as a private law contract.

The UK government also published the full draft Low Carbon Hydrogen Agreement in August 2023, and intends to award the first contracts at the end of 2023. In addition, the UK government confirmed that a second allocation round (HAR2) will be launched at the end of 2023 with the intention of awarding contracts for 750 MW of green hydrogen capacity in 2025 (up from the 250 MW of capacity expected to be awarded in the first allocation). Following HAR2, the government has announced that it intends to transition to an annual, price-based competitive allocation for Low Carbon Hydrogen Agreements by 2025 for electrolytic projects.

The Net Zero Hydrogen Fund (NZHF), worth up to £240 million, funds the development and deployment of new low-carbon hydrogen production to de-risk investment and reduce lifetime costs. The second application round for strand 1 (which provides development expenditure for front-end engineering design (FEED) and post-FEED activities) and strand 2 (which provides capital expenditure support for hydrogen production projects that do not require revenue support through the Low Carbon Hydrogen Agreement) closed this year.

Nuclear

As noted above, a key component of the "Powering up Britain" energy security plan is the government's commitment to nuclear energy, with an ambition of achieving civil nuclear deployment of 24 GW by 2050. This represents approximately 25 per cent of projected demand, up from the 14 per cent of demand serviced by nuclear today.

As mentioned in the first part of this chapter, however, the UK's nuclear capacity is diminishing. After the closure of two nuclear plants in 2022, the UK has just nine operational reactors, all of which are due to be retired by 2035.

Despite the introduction of RAB financing models for new nuclear, only one RAB-funded conventional nuclear power station has been approved: Sizewell C. As such, a significant gap in nuclear capacity is expected in the late 2020s to early 2030s. To resolve this, the government has created an arm's-length body, GBN, to accelerate the UK's goal of reaching 24 GW of capacity by 2050.

GBN's primary role to date has been the launch of a competition to find the leading designs for SMRs. SMRs produce up 300 MWe of output, much less than conventional reactors, which produce over 700 MWe. Unlike conventional reactors, however, SMRs can be prefabricated in factories and transported for installation, reducing both the time and cost of construction. Further, due to their much smaller size, SMRs require far fewer site-specific adjustments, allowing the government and operators to leverage existing, decommissioned infrastructure, such as old coal-fired power stations to site new SMRs. It is hoped that the reduced construction times will allow the UK to commission and power up SMRs across the country in time to address the capacity gap that will be left by decommissioned conventional reactors.

Another advantage of having more, less powerful, reactors will be the ability to utilise incremental deployment to effectively manage power supply to the grid. Safety will also be much improved, given that SMRs are able to operate using natural failsafes, unlike conventional reactors, which require human input to prevent catastrophe.

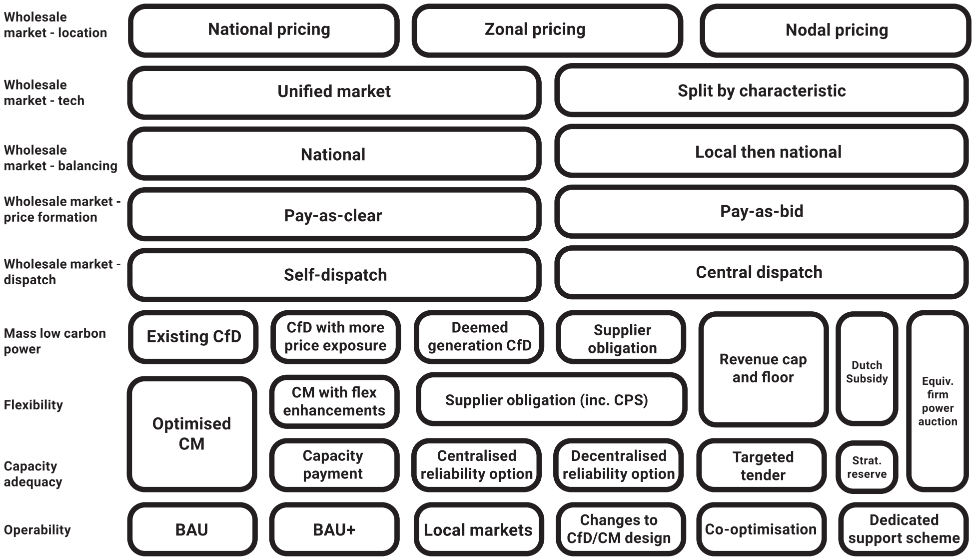
GBN has committed to co-funding winning bids if they are "demonstrated to be viable", with Rolls-Royce SMR having previously received £210 million in government grants. Beyond Rolls-Royce, five other firms (Holtec Britain, GE Hitachi Nuclear Energy International, EDF, NuScale Power and Westinghouse) have been shortlisted. GBN and the government are expected to make final investment decisions by 2029. The government has also announced that grants worth up to £157 million will be made available to accelerate the development of a nuclear business in the UK and designs for new, advanced modular reactors capable of operating at higher temperatures.

Review of Electricity Market Arrangements

As discussed in detail in the 2023 edition of this chapter, in 2022, the government launched its Review of Electricity Market Arrangements (REMA). REMA focuses on options for reform for all non-retail electricity markets: the wholesale market, balancing mechanism and ancillary services; as well as policies that impact them – including the evolution of and alternatives to the CfD scheme and the CM. The original REMA consultation closed in October 2022, and in March 2023, the government published a summary of responses[11] to the consultation. A second consultation is scheduled to take place in 2023.

The government has said that the driver for REMA is the fact that current electricity market arrangements are getting in the way of energy transformation because they were largely built for fossil fuel generation. In trying to fix the pent-up problems, it has set the scope very wide. The options range from fundamental reforms of the wholesale market to incremental changes to CfDs and the CM. Figure 2 from the REMA consultation paper illustrates the myriad of proposals being considered.

Figure 2: proposals being considered by REMA[12]



Developments in legislation or regulation

<u>Energy Act 2023</u>

In July 2022, the government laid before Parliament a new Energy Bill, to provide the legislative framework required for a large number of different initiatives being taken forward, some of which are discussed above. In most cases, to fully implement the relevant proposals, a large number of secondary legislation (usually in the form of Regulations) will also be required. The Energy Act 2023 received Royal Assent on 26 October 2023.

Some of the main areas that the Energy Act 2023 deals with include:

- a new regulatory regime for CCUS, which includes a licensing system, appointment of a regulator (Ofgem, the gas and electricity markets regulator) and financial support for carbon dioxide emitters who use the carbon dioxide T&S networks;
- revenue support for producers of clean hydrogen;
- the development of a regulatory framework for low-carbon heat schemes;
- the creation of a new publicly owned entity – an Independent System Operator and Planner (ISOP) to take on all the functions of the existing electricity system operator and some of the functions of the existing gas system operator;
- reform of the governance arrangements for the various gas and electricity industry codes;
- changes to the regime that applies in relation to offshore electricity transmission;
- facilitating the establishment of multi-purpose electricity interconnectors;
- a regulatory regime for heat networks, with Ofgem being the regulator for heat networks in the same way that Ofgem already regulates gas and electricity networks and will also regulate carbon dioxide T&S networks;

- new powers for the Secretary of State to maintain continuity of core fuel supplies (oil and renewable transport fuels) and ensure that industry maintains or improves its resilience to reduce the risk of emergencies affecting fuel supplies;
- extending the remit and powers of the Civil Nuclear Constabulary; and
- amending the model clauses (conditions) of upstream oil and gas licences to require three months' notice of any proposed changes of control of a licensee and NSTA consent before the transfer of ownership can complete.

Judicial decisions, court judgments, results of public enquiries

2023 has seen a continuation of the recent rise in litigation involving challenges of government policies and decisions on grounds relating to climate change objectives and environmental protection.

Most recently, environmental groups Greenpeace and Uplift applied for and were granted permission to bring a judicial review challenge to the decisions to go ahead with the 33rd offshore oil and gas licensing round. Specifically, the claimants seek to challenge the 33rd licensing round on the basis that:

- the Secretary of State failed to provide any reasons for the new licensing round being compatible with the CCC and the UK's climate objectives; and
- the decision to adopt the CCC was unlawful because it excluded a test that would have required the Secretary of State to consider downstream emissions (i.e. the emissions from the produced oil and gas being used).

The High Court[13] rejected the judicial review challenge, stating, among other things, that the question of whether a decision to grant licences for oil and gas exploration and production would be compatible with achieving the Net Zero target is a matter of judgment and not law.

Major events or developments

There have been no major events or developments other than those discussed elsewhere in this chapter.

Proposals for changes in laws or regulations

The Offshore Petroleum Licensing Bill was introduced in Parliament on 8 November 2023. Currently there is no requirement that offshore petroleum licensing rounds should be run on a regular basis, although, until recently, they usually took place on an annual basis as a matter of practice. This Bill seeks to place the NSTA under a new duty to run annual offshore licensing rounds, although this will still be subject to the Climate Compatibility Checkpoint referred to earlier in this chapter.

* * *

Endnotes

1. Digest of UK Energy Statistics Annual Data for UK, July 2023.
2. https://www.nstauthority.co.uk/news-publications/net-zero-boost-as-carbon-storage-licences-accepted
3. https://www.energy-uk.org.uk/wp-content/uploads/2023/05/Energy-UK-AR5-response.pdf
4. https://www.proactiveinvestors.co.uk/companies/news/1022800/bp-mulls-subsidy-free-wind-farm-plan-1022800.html

5. https://www.gov.uk/government/calls-for-evidence/introducing-non-price-factors-into-the-contracts-for-difference-scheme-call-for-evidence
6. https://www.ofgem.gov.uk/publications/consultation-regulatory-framework-including-market-arrangements-offshore-hybrid-assets-multi-purpose-interconnectors-and-non-standard-interconnectors
7. https://www.nationalgrideso.com/document/281561/download
8. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1162454/capacity-market-2023-consultation-government-response.pdf
9. https://www.gov.uk/government/calls-for-evidence/introducing-fixed-price-certificates-into-renewables-obligation-schemes-call-for-evidence
10. https://www.gov.uk/government/consultations/heat-networks-regulation-consumer-protection
11. https://www.gov.uk/government/consultations/review-of-electricity-market-arrangements
12. Review of Electricity Market Arrangements, BEIS, July 2022.
13. *R (on the application of Greenpeace Limited) v Secretary of State for Energy Security and Net Zero, Oil and Gas Authority* [2023] EWHC 2608 (Admin).

* * *

Acknowledgment

The authors would like to thank Abu-Bakr Samad, trainee solicitor at Ashurst LLP, for his valuable contribution to the preparation of this chapter.

Michael Burns
Tel: +44 20 7859 2089 / Email: michael.burns@ashurst.com
Michael Burns is a partner in Ashurst's corporate practice and Ashurst's global co-head of energy, based in London. Michael specialises in M&A, joint ventures and major project development with a focus on the energy and infrastructure sectors. He leads Ashurst's energy and infrastructure M&A business in EMEA. Michael's clients include multinational corporates, financial institutions, governments and high-net-worth individuals.

Antony Skinner
Tel: +44 20 7859 1360 / Email: antony.skinner@ashurst.com
Antony Skinner is a partner in Ashurst's projects practice, based in London. Antony specialises in the development, financing and M&A of renewable and thermal power, as well as other components of the energy supply chain, including battery storage and gas/electricity distribution and retail. Antony has advised sponsors and lenders, purchasers and vendors in a range of transactions in relation to renewables and power generation developments, and in connection with a number of renewable portfolio acquisitions and financings.

Justyna Bremen
Tel: +44 20 7859 1848 / Email: justyna.bremen@ashurst.com
Justyna Bremen is a senior expertise lawyer in Ashurst's projects practice, based in London. She has extensive experience in the energy sector, covering both power and oil and gas, with a particular interest in upstream oil and gas, renewables, decarbonisation technologies and downstream gas and electricity market regulation.

Ashurst LLP
London Fruit & Wool Exchange, 1 Duval Square, London, E1 6PW, United Kingdom
Tel: +44 20 7638 1111 / URL: www.ashurst.com

USA

Regina Speed-Bost
SB Law, PLLC

Overview of the current energy mix, and the place in the market of different energy sources

Primary energy sources include fossil fuels (petroleum, natural gas, and coal), nuclear, and renewable sources of energy. Electricity is considered a secondary energy source because it is generated (produced) from primary energy sources.

In the United States, British thermal units (Btu), a measure of heat energy, are commonly used for comparing different types of energy to each other. In 2022, total U.S. primary energy consumption was equal to about 100.4 quadrillion, a 3% increase from 2021.

See, https://www.eia.gov/todayinenergy/detail.php?id=56980

Changes in the energy situation in the last 12 months that are likely to have an impact on future direction or policy

The U.S. energy market is subject to many of the same challenges faced globally this year. With the priority of addressing global climate change, the U.S. energy industry is attempting to transition to a greater reliance on renewable energy. On the electricity front, this means focusing on expanding our transmission infrastructure to enable more renewable resources to replace fossil fuel-based sources of electric generation. The electric power sector has been challenged to make this transition, with timelines in some jurisdictions having been revised and are now as early as 2030.

On the natural gas front, the significant natural gas reserves identified in the Permian, Utica, Appalachian, and other U.S. basins supported an estimated increase in U.S. gas consumption in 2022 to an average of 88.5 Bcf/d for the year.

See, https://www.eia.gov/todayinenergy/detail.php?id=55800#:~:text=In%202022%2C%20U.S.%20natural%20gasto%20records%20beginning%20in%201949

The projected increase is related to geopolitical tensions globally, including the war in Ukraine, ongoing U.S. tensions with China, and the desire to rely more on domestic production of petroleum. The United States became a net exporter of natural gas in 2017 for the first time since the 1950s.

The energy consumption in 2022 also reflected the realities of post-pandemic, return to office policies. As employers and business owners began to encourage a return to pre-pandemic work patterns, hybrid work schedules that allow a mix of remote and in-office accommodations also suggest new energy usage patterns that had to be reconciled with old. Indeed, even traditional ratemaking concepts are leaning in the direction of newer constructs as time-of-use rates and similar structures may be more rational in our post-pandemic world. Moreover, supply chain issues and shortages only serve to slow the pace of the clean energy transition.

The uncertainty surrounding the clean energy transition, global geopolitical unrest, and supply chain issues create a level of price volatility that rivals that seen in the United States in the 1970s. Questions regarding the extent to which the clean energy transition exacerbates supply chain issues, thereby adding to price volatility, abound. These issues are likely to impact the U.S. energy sector well into 2024 and beyond.

Developments in government policy/strategy/approach and legislation and regulation

The Biden Administration continues to place reducing greenhouse gas emissions emanating from the United States as a governmental priority and ties this priority to most significant U.S. domestic and international policy initiatives. In February 2022, Congress passed the American Energy Independence and Security Act of 2022. Among other things, the law addresses U.S. energy independence, and the production and importation of oil and natural gas. It calls on the President to develop a plan for the United States to achieve energy independence by 2024 and the U.S. Department of Energy (DOE) to develop a programme and issue rules to ensure that the United States achieves such energy independence and becomes a net exporter of energy.

See, https://www.congress.gov/bill/117th-congress/senate-bill/3714#:~:text=Introduced%20in%20Senate%20(02%2F28%2F2022)&text=This%20bill%20addresses%20U.S.%20energy,achieve%20energy%20independence%20by%202024

In August 2022, Congress passed the Inflation Reduction Act of 2022, which makes the single largest investment in climate and energy in U.S. history, enabling the United States to tackle the climate crisis, advancing environmental justice, securing the United States' position as a world leader in domestic clean energy manufacturing, and putting the United States on a pathway to achieving the Biden Administration's climate goals, including a net-zero economy by 2050.

Judicial decisions, court judgments, results of public enquiries

In June 2022, the U.S. Supreme Court issued its decision in *West Virginia et al. v. Environmental Protection Agency et al.* and found that the U.S. Environmental Protection Agency (EPA) did not possess the statutory authority needed to implement the Clean Power Plan, a 2015 administrative rule intended to reduce U.S. greenhouse gas emissions nationally by requiring the replacement of coal-fired electric power generation with natural gas-fired and renewable energy generation. The U.S. Supreme Court found that the EPA had misinterpreted the language in Section 111d of the Clean Air Act and inappropriately expanded the agency's authority as a result.

West Virginia et al. v. EPA et al. has significant implications for energy production and use in the United States because, to a large degree, it has been the EPA's efforts in enforcing the Clean Air Act that have pushed the clean energy transition. Absent this push from the EPA, it is uncertain whether the goal of a net-zero economy by 2050 is attainable. In addition, the case has significant implications for the power of U.S. administrative agencies to interpret their governing statutes and may mark a new level of restraint being imposed on those agencies.

Regina Speed-Bost
Tel: +1 202 963 2701 / Email: rspeed-bost@sblawlegal.com
Regina Speed-Bost has over 30 years of legal and regulatory experience practising before the Federal Energy Regulatory Commission and various state public service and public utilities commissions. Regina represents a variety of interests in the energy sector, including electric public utilities, natural gas local distribution companies, and renewable energy companies. SB Law, PLLC (https://sblawlegal.com) is a minority-owned, woman-owned energy regulatory law firm, established in 2020 in the midst of the worldwide coronavirus and U.S. social justice pandemics. Having studied the practice of law as a business for over 10 years while practising energy regulatory law for over 30 years, our founder created a practice that would meet the needs of energy clients while also speaking to the heart of her community.

SB Law, PLLC

200 Massachusetts Ave., NW, 7th Floor, Washington, D.C. 20001, USA
Tel: +1 202 963 2700 / URL: www.sblawlegal.com

Zambia

Joseph Jalasi, Jr., Lubinda Linyama, Nsokola Chilwana &
Wana Chinyemba
Dentons Eric Silwamba, Jalasi & Linyama Legal Practitioners

Overview of the current energy mix, and the place in the market of different energy sources

The energy sector in Zambia is chiefly governed by various pieces of legislation and principally the Energy Regulation Act No. 12 of 2019 (the Energy Act). Notably, the Energy Act defines "energy" as follows in Section 2:

> "*"energy" means—*
>
> *a source of electrical, mechanical, thermal, nuclear or chemical power for any use, and includes electricity, petroleum, coal, other fossil fuels, geothermal, natural gas, biomass and its derivatives municipal waste, solar, wind and tidal wave power; and energy produced by any other means that the Minister may, on recommendation of the Board, prescribe by statutory instrument.*"

The definition of energy encompasses electrical, mechanical, thermal or chemical power generated from various sources with an allowance that, in the Statute books, other sources of energy may be recognised.

As a primer, Zambia possesses a diversity of energy sources that are native to it. These are hydropower energy, coal, biomass, and renewable energy sources such as sunlight. Furthermore, petroleum is also an energy source in Zambia. However, Zambia is not an oil-producing country and therefore solely imports it.

From the foregoing, the three primary sub-sectors of the Zambian energy sector are the following: electricity; renewable energy; and petroleum.

Historically, since the British colonial era spanning from about 1888 to 1964, hydropower has been the principal source of electrical energy, with some thermal energy being generated through a coal power plant, i.e. Maamba Collieries Limited (MCL). However, in the last two decades, there has been a growth, to a minor extent as compared to hydropower and thermal power, of energy generated through heavy fuel oil, diesel and solar photovoltaic, commonly referred to as solar power plants. Roughly, the current installed generation capacity of energy is 83% of energy deriving from hydropower, 9% from coal, 5% from heavy fuel oil and 3% from solar photovoltaic.

The alternative energy sources have arisen owing to the demands of increasing industrialisation and the increasing demand of electricity arising from an increase in population.

It is noteworthy with regard to electrical energy that loadshedding has been experienced in Zambia from as early as 2006, with a drastic increase in about 2015 and a slightly stabilised capacity as of 2023. This is vital considering the energy market composition in Zambia, which has predominantly operated on a single-buyer model, with Zambia Electricity Supply Corporation Limited (ZESCO), a state parastatal, serving as the sole purchaser and major distributor of electricity across the interconnected national system.

However, independent power producers have also played a role in generating electricity and managing their own facilities, even though they have historically produced and sold their produced electricity to ZESCO through contracts known as power purchase agreements (PPAs).

With energy being considered an essential commodity for human livelihood, the Zambian energy sector is strictly regulated. The Energy Act established the Energy Regulation Board (ERB), which is mandated to determine, regulate and review charges and tariffs in the energy sector, and also approve, review and regulate PPAs and power supply agreements, *inter alia*.

This means that energy generation activities are subject to the regulatory oversight of the ERB, including any energy transactional activities. The scope of energy generation and distribution activities is largely affected by various Governmental policies and directions taken.

Notably, the United Party for National Development through Government Gazette Notice No. 1123 of 2021, published on Friday 24th September 2021 in Government Gazette No. 7039, Volume LVII, No. 90, introduced the Ministry of Green Economy and Environment. This novel ministry is responsible for biosafety, carbon credit policy, climate change policy, environmental policy, environmental protection and pollution control, environmental research and training, forestry extension and development, forestry policy, green economy and industrial policy, and meteorological services.

This development has resulted in an increasing investor interest in renewable energy generation, a larger share contribution of alternative energy sources to the energy pool and an anticipated increase in the energy contribution from the renewable energy sector.

Changes in the energy situation in the last 12 months that are likely to have an impact on future direction or policy

The continued Russia-Ukraine conflict has resulted in supply-side disruptions and the consequent increase in the cost of acquiring critical commodities such as petroleum products.

In addition, according to the Ministry of Energy, the country experienced low importations of petrol by oil marketing companies, which was attributed to an alleged non-responsive pricing mechanism that is carried out every 30 days.[1]

Additionally, in the last 12 months, the country has experienced more loadshedding attributed to low water levels in the Kariba Dam, which is a key source of hydropower. The loadshedding has also been attributed to energy export to South Africa.

Developments in government policy/strategy/approach

The developments in Governmental policy, strategy and approach are ascertainable by an appraisal of the 2023 and 2024 Budget Address by Honourable Dr. Situmbeko Musokotwane, Member of Parliament, Minister of Finance and National Planning Delivered to the National Assembly of Zambia, respectively.

The notable areas of Governmental policy, strategy and approach include the following:

1. Ensuring the recommencing and increase of coal production. As at 17th January 2023, MCL resumed its operation and electricity generation at full capacity.
2. Ensuring that a framework is created that will enable the Government to secure golden shares in mines, including mines producing energy resources.
3. Promoting the manufacturing of electric car batteries.
4. Government withdrawal from participating in the fuel supply chain to ensure an open market participation approach. This is underpinned by the Government assuming the

role as merely a regulator of the petroleum sector, ensuring that the petroleum sector embraces cost-effective pricing, maintaining strategic reserves.

5. Conversion of the Tanzania-Zambia (TAZAMA) Pipeline from a petroleum feedstock carrier to a carrier of finished products, i.e. diesel, as well as creating regulations that will facilitate the opening of the TAZAMA Pipeline to allow third-party access to the pipeline. Additionally, invitations were made for private sector participation and investment in a new pipeline. The TAZAMA Pipeline is a pipeline that runs from the Indian Ocean port of Dar es Salaam in Tanzania to Ndola, Zambia. The Government of the Republic of Zambia and the Tanzanian Government are joint owners of the pipeline through a company in which they are joint owners/shareholders.
6. Embarking on 62 grid-tiered electrification projects and 19 solar mini-grid projects in 2023, with work being commenced on some projects.
7. A proposal by the Government to remove customs duty on machinery, equipment and other goods for geothermal activities.
8. Removal of customs duty on electric motorcycles, electric vehicles, electric buses, electric trucks, and attendant accessories such as charging systems.
9. Reducing excise duty to 25% from 30% pertaining to hybrid vehicles for transportation of persons.
10. Promoting oil and gas exploration by removing customs duty on machinery, equipment and other goods designed for petroleum production.
11. Resuming operations at INDENI Oil Refinery as at 25th June 2023, with distribution beginning on 27th June 2023 and an increased supply volume of 30%, with the overarching goal of ensuring that INDENI ceases to process feedstock. The INDENI Oil Refinery is a refinery owned by the Government and wherein petroleum products transported through the TAZAMA Pipeline are offloaded.
12. The Government signed a green growth compact worth £1 billion in 2022 with the United Kingdom Government with the expectation that this Foreign Direct Investment would boost the renewable energy sector, *inter alia*.
13. The Government is taking steps to develop carbon marketing and trading guidelines, including guidelines and listing rules for green bond trading in accordance with the Kyoto Protocol on climate change.

    The Ministry of Green Economy and Environment released interim guidelines for overseeing carbon markets and trading activities in Zambia (the Guidelines). In contrast to the Forests Carbon Stock Management Regulations, Statutory Instrument No. 66 of 2021, which specifically pertain to the governance of forest carbon projects, the Guidelines encompass a broader array of eligible carbon initiatives.

    The Guidelines serve as preliminary administrative measures and procedures, providing essential direction for the regulation and administration of Zambia's carbon market until the Climate Change Act becomes law.

    The reliability of carbon offsets is of utmost importance for upholding the credibility of any carbon market, directly influencing the quality and value of the resultant carbon offsets. The primary objective of the Guidelines is to ensure that carbon market trading and oversight in Zambia not only aligns with international best practices but also delivers tangible benefits to local communities who are the custodians of the natural resources involved.

    The Government also intends to ensure that income earned on green bonds listed on the securities exchange are exempt from withholding tax with a maturity of at least three years to encourage investment in projects with environmental benefits as per the 2022 National Budget.

14. As of 2022, removal of the 15% customs duty on gas cylinders with liquefied petroleum gas to ensure that it is affordable to the general Zambian populace and to further safeguard and diversify the energy mix.
15. Installation of 200 kilometres of powerlines in Luena, Luswishi and Shikabeta to facilitate installation of electrical power lines in farms.
16. Signing of an Implementation Agreement: The Government signed an Implementation Agreement with Africa GreenCo Group through its Zambian subsidiary GreenCo Power Services Limited. The tenor of the Implementation Agreement is that the Government has demonstrated an interest in developing the energy sector, mitigating climate change and broadening the electricity market.

    This is a significant milestone because it will foster funding and boost expertise for infrastructure in clean or green energy.
17. Steps to introduce slate mechanisms: The Government plans to ensure that any under-collections by importers of fuel are compensated in the following month and *vice versa*. These under- and over-collections are computed for each day in the fuel price review period, and an average exchange rate for the fuel price review period is calculated. The current mechanism for the exchange rate component does not allow for under- and over-collections.
18. Peer review of the petroleum pricing mechanism: The Government plans to carry out an independent review of the petroleum pricing mechanism to ensure its adequacy. This review will be conducted through an independent peer review process.
19. Introduction of a private sector-led system for bulk importation of petroleum products: The Government is planning to implement a private sector-led system for bulk importation of petroleum products, known as the Zambia Bulk Procurement System. This system aims to establish more stable and efficient importation and distribution of petroleum products in Zambia.
20. Widening private sector participation in the fuel supply chain: In the petroleum industry, as of October 2022, the Ministry of Energy, responsible for electricity, energy regulation, higher authority for power (special provisions), petroleum, rural electrification and management of the TAZAMA Pipeline, and the Zambezi River Authority adopted a policy of disengaging from financing and procuring petroleum products for the Zambian market. The policy direction aims to enhance and widen private sector participation in the fuel supply chain and thereby takes the leading role.
21. The signing of a Memorandum of Understanding between the Government of the Republic of Zambia and United Arab Emirates investors to secure investment in renewable energy in Zambia, including installing a solar power plant that will feed into the national power grid.
22. Steps to develop net metering guidelines: In 2022, the Ministry of Energy circulated draft Net Metering Regulations for the comment of stakeholders. The Draft Regulations are yet to be finalised and approved by Parliament.

    Regulation 4 (2) and (3) of the Draft Net Metering Regulations provides as follows:

    "*(2) The consumer can apply for a net-metering generation up to the capacity of his grid connection capacity and beyond the capacity of his grid connection capacity.*

    (3) Applied net-metering generation capacities shall not consider no operating generation reserve."

    Net energy metering is available for small-scale solar projects subject to approval from the ERB as stipulated above. Any limits on how much power can be fed back into the grid will be expressly stated in the approvals received from the ERB.

The pricing of the electricity fed back into the grid is determined by the ERB. Approvals from the ERB and the Zambia Environmental Management Agency are required to install net metering.

Developments in legislation or regulation

In accordance with the Energy Act, the Ministry of Energy has put into effect the Energy Regulation (Appeals Tribunal) Rules, Statutory Instrument No. 5 of 2023. The Energy Regulation (Appeals Tribunal) Rules are a critical component of the regulatory framework in the energy sector because they provide for the procedure applicable in the Tribunal mandated to hear appeals against decisions of the ERB that a party is aggrieved with.

The Energy Tribunal is a specialised body composed of experts in the energy sector and reposed with the responsibility to ensure timely resolution of disputes.

Notably, stakeholders have a means to challenge perceived unfair or incorrect decisions, thereby contributing to the integrity and effectiveness of the energy regulatory system. The purpose of the Energy Regulation (Appeals Tribunal) Rules is to provide a structured and transparent framework for handling appeals related to energy regulation decisions. These rules serve several important functions:

1. Ensuring fairness and due process: The Energy Regulation (Appeals Tribunal) Rules are designed to ensure that parties involved in energy regulation disputes have access to a fair and impartial process. They outline the procedures that must be followed to safeguard the rights of all parties involved.
2. Resolution of disputes: The rules establish the mechanisms and processes for resolving disputes between stakeholders in the energy sector. These may include disputes related to regulatory decisions, licensing, compliance with energy laws and regulations, tariff setting, and more.
3. Efficiency: By outlining clear procedures and timelines, the rules help to ensure that appeals are processed efficiently, which can be crucial in a sector as vital as energy, where decisions often have a significant impact on the economy and public welfare.
4. Consistency: The rules are intended to help promote consistency in decision-making and dispute resolution within the energy regulatory framework, ensuring that similar cases are treated similarly.
5. Accountability: The rules establish mechanisms for holding regulatory authorities accountable for their decisions and actions. If a regulatory decision is deemed flawed or unjust, the appeals process allows for a review of that decision.

Judicial decisions, court judgments, results of public enquiries

In the case of *The People v. The Attorney General and The Energy Regulation Board* [2020] HP 0575, the applicant made an application for judicial review against the following decisions:

i. the Minister of Energy's decision under the provisions of the Electricity (common carrier) Regulations, Statutory Instrument No. 57 of 2020 dated 29th May 2020 declared Copperbelt Energy Corporation (CEC) transmission and distribution lines as common carriers; and
ii. the decision by the Director-General of the ERB dated 31st May 2020 directed CEC to charge a wheeling (i.e. transmission) tariff of USD 5.84/KW/month.

The Court of Appeal held as follows:

i. the Minister's decision to declare CEC's transmission and distribution lines as a common carrier is unlawful;

ii. a declaration that the Minister's direction for CEC to provide a wheeling path for ZESCO to supply power to Konkola Copper Mines on terms dictated by the ERB is illegal and therefore null and void;
iii. a declaration that the Minister of Energy's decision to issue SI 57 of 2020 was illegal; and
iv. a declaration that the wheeling tariff of USD 5.84/KW/month is illegal and therefore null and void.

The holding of the Court underscores the importance of extending procedural fairness to even the largest corporations when they engage with the Government. In rendering its verdict, the Court meticulously examined the facts and legal considerations outlined earlier, ultimately concluding that the Minister had failed to ensure procedural fairness in the company's dealings. This was particularly evident due to the overly broad scope of the Statutory Instrument in question.

Of particular note is the decision to designate CEC's transmission lines as common carriers, an action that impacted all of the company's lines, including those dedicated to serving other clients in the Copperbelt region and the Democratic Republic of the Congo. The sentiments expressed by the Court in this judgment serve as an encouraging sign for investors who may have harboured doubts about the level of fairness they could receive from the Government in matters related to energy regulation.

Furthermore, another notable judicial decision includes *Astor Investments Limited v. Zambia Electricity Supply Corporation Limited* 2014/HK/143, in which the High Court of Zambia ruled as follows:

> "*The Court has jurisdiction upon an interlocutory application to grant a mandatory injunction directing that a positive act should be done to repair some omission or to restore the prior position by undoing some wrongful act but it is a very exceptional form of relief...*"

This decision highlights that energy producers are responsible and may be liable to repair any environmental damages caused by their activities.

Conclusion

From the foregoing, it is clear that the energy sector continues to undergo reforms driven by Governmental policies aimed at enhancing the energy sector and ensuring a climate-friendly energy generation framework. Furthermore, the Government seeks to diversify energy generation sources as opposed to the traditional hydro-energy.

* * *

Endnote

1. Proceedings of the National Assembly, Thursday 29th June 2023, https://www.parliament.gov.zm/node/11149

Joseph Jalasi, Jr.
Tel: +260 211 256 530 / Email: joseph.jalasi@dentons.com
Joseph Alexander Jalasi, Jr. is the Head of the Tax, Mining, Corporate, Banking and Finance Department. He has several years' experience in public litigation as Principal State Advocate in the Attorney General's Chambers. He is a former Registrar of the Tax Appeals Tribunal. He has several cases to his credit in the Zambian Law Reports. Mr. Jalasi served as Chief Policy Analyst, Legal Affairs at State House under the late President Levy Mwanawasa and he served as legal advisor to former President Rupiah Banda. He is a member of the Chartered Institute of Arbitrators of the United Kingdom and is also a qualified legal draftsperson.

Lubinda Linyama
Tel: +260 211 256 530 / Email: lubinda.linyama@dentons.com
Lubinda Linyama is a Partner at the firm. He has acquired vast experience in diverse areas of litigation, *inter alia*, commercial law, criminal law, administrative law, mining law and general business law, corporate advisory in major areas of company law, secretarial services for various locally owned and multinational companies operating in Zambia, and corporate compliance. Equipped with negotiating skills, Mr. Linyama was part of the main and sub-committees of the negotiations between the Government of the Republic of Zambia and Chinese investors on the Multi-Facility Economic Zones (MFEZ) for the Chambishi and Lusaka areas of the Republic of Zambia, and was involved in drafting the Investment Promotion and Protection Agreement for the MFEZ.

Nsokola Chilwana
Tel: +260 211 256 530 / Email: nsokola.chilwana@dentons.com
Nsokola Chilwana is an Associate at the firm with wide experience in various types of litigation, mediation, family law and real estate law, immigration law, gaming law, taxation and debt collection. Mr. Chilwana is highly skilled and has advised several multinational clients in complex cases.

Wana Chinyemba
Tel: +260 211 256 530 / Email: wana.chinyemba@dentons.com
Wana Chinyemba joined the firm in 2021 after graduating from the University of Zambia with an LL.B. He has since gained experience in tax, banking and finance, and general corporate advisory. He was recently admitted to the Zambian Bar.

Dentons Eric Silwamba, Jalasi & Linyama Legal Practitioners
Plot No. 12 at William Burton Place Chilekwa Mwamba Road, Off Lubu/Saise Roads, Longacres, Lusaka, Zambia
Tel: +260 211 256 530 / URL: www.dentons.com

www.globallegalinsights.com

Global Legal Insights – Energy provides in-depth analysis of laws and regulations across 14 jurisdictions, discussing the current energy mix, changes in the energy situation in the last 12 months, developments in government policy and strategy, developments in legislation or regulation, judicial decisions and court judgments.

GLI GLOBAL LEGAL INSIGHTS