Clean power in South Korea

A roadmap to zero fossil gas in South Korea's power sector

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Summary

Clean electricity is a key milestone on the road to net zero. To achieve this goal, coal and fossil gas generation need to be phased out urgently. This report develops a 1.5°C compatible pathway for fossil gas generation in South Korea's power sector and two phaseout schedules for the country's gas fleet prioritised by cost and health which meet this pathway.

South Korea's power sector is dominated by fossil fuels, which provided over 60% of generation in 2021. While plans are being developed to reduce fossil gas consumption, current policies are not ambitious enough. Under the 10th Basic Electricity Plan, fossil gas would still provide 23% of electricity in 2030. This does not align with the Paris Agreement's 1.5°C limit.

South Korea needs to phase out gas in the power sector by 2034

In the central 1.5°C compatible pathway we produce, power sector emissions fall 90% from 2022 to 2030 and reach zero by 2034 (Figure ES1). To achieve these reductions, fossil gas generation needs to fall 60% from 2022 to 2030, and fossil gas should be phased out entirely by 2034, and as early as 2031.

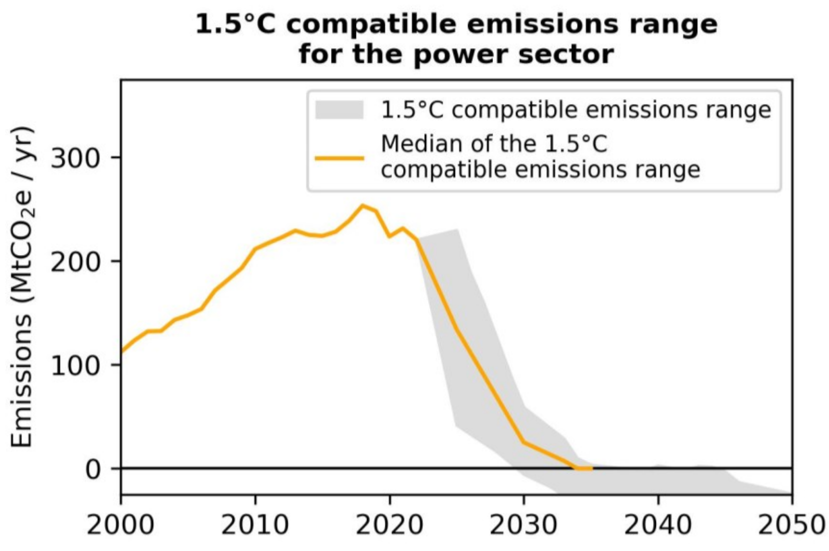

Figure ES 1: A 1.5°C compatible pathway for South Korea's electricity system.

There can be no new gas power stations or coal-to-gas conversions

In the 1.5°C compatible pathway, there is no scope for building new fossil gas units post-2023. All units which are due to be finalised post-2023 would need to be cancelled. There is also no scope for planned coal-to-gas conversions in this 1.5°C compatible pathway.

The fossil gas phaseout needs to start immediately

The transition is front-loaded, with a large number of units which need to be retired this year. We develop two phaseout schedules, which focus on maximising the economic and health benefits of the transition (Figure ES2). **We identify 18 units which are phased out by the end of 2023** in both phaseout schedules. These units are old, inefficient, highly polluting and expensive.

South Korea has more than enough renewable resources to replace fossil fuels in the power sector and meet future demand

There is abundant renewable potential in South Korea, particularly in offshore wind and utility-scale solar PV. To meet future electricity demand and phase out fossil fuels, our illustrative pathway shows an additional 1500 TWh of renewable generation would be required by 2035. Our detailed analysis finds the country has over three times more renewable potential (5000 TWh) than projected demand.

Phasing out fossil gas in South Korea would bring a wide range of benefits, from cost savings and energy independence to reduced air pollution, improved health and new jobs in the industries of the future, as well as helping to deliver on South Korea's commitments under the Paris Agreement.

A fossil gas phaseout by the mid-2030s is feasible but requires immediate action. Incremental action, as seen in the 10th Basic Electricity Plan, will not lead to alignment with 1.5°C or enable South Korea to reap the rewards of its renewable potential. South Korea has an opportunity to accelerate action in this critical decade for the climate. This report sets out a clear roadmap to achieving this in the power sector.

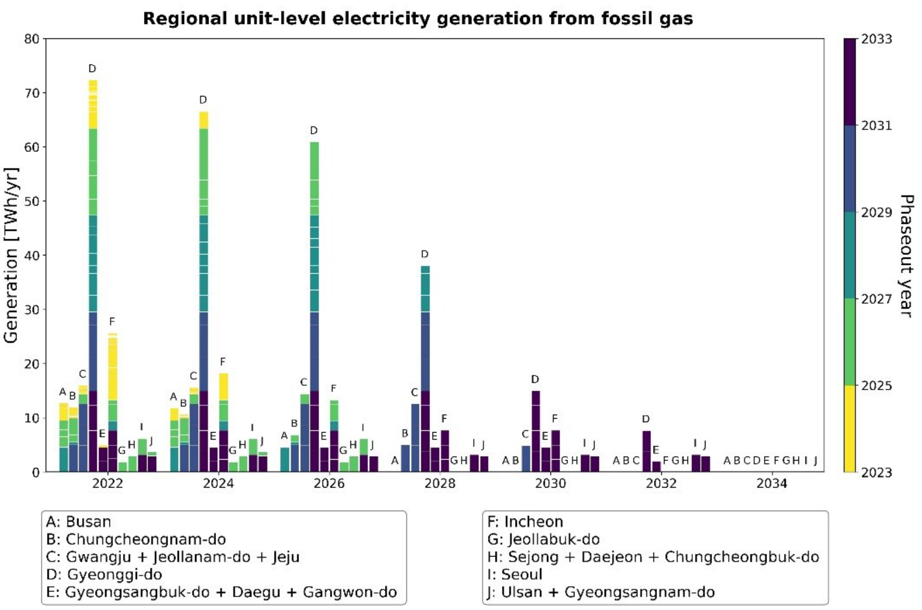

Figure ES 2: A unit-by-unit phaseout schedule for fossil gas plants in South Korea.

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Introduction

Clean power is critical for achieving a fully decarbonised energy system and will bring many benefits – from lower costs (Way et al., 2022) to cleaner air (Climate Analytics, 2021), job creation (Climate Analytics and Solutions for Our Climate, 2021) and domestic energy independence (Scholten and Bosman, 2016). Achieving a decarbonised power sector is a key enabler of the transition (IEA, 2021a), as other parts of the energy system such as buildings, transport and industry are increasingly electrified. This requires the displacement of fossil-based generation, and a rapid scaling up of renewable alternatives.

South Korea's power sector is dominated by fossil fuels, which in 2021 provided over 65% of electricity generation (Ember, 2022). However, in South Korea new gas plants are still being planned and built, and ageing coal power plants are being converted to run on fossil gas instead of being fully retired (Lee, 2023). Crucially, no clear roadmap exists to achieve a fossil gas phaseout at the unit level[1], and no clear phaseout date has been set for the gas fleet.

This report produces a 1.5°C-aligned emissions pathway for the phaseout of fossil gas plants in the country and details how this pathway could be realised on a unit-level basis.

We provide insight into the current policy context in South Korea, focusing on the recently finalised 10th Basic Electricity Plan which sheds light on the future plans for the country's power generation mix (Ministry of Trade Industry and Energy, 2023). Based on the latest IPCC findings, we develop a 1.5°C compatible emissions pathway for the South Korean power sector. This is used to calculate a 1.5°C compatible pathway specifically for fossil gas electricity generation. In this pathway, fossil gas generation falls more than 50% by 2030, and is phased out entirely by 2034.

Using this pathway, we perform a detailed multi-criteria analysis of the current South Korean gas power fleet on a unit-by-unit level. We arrive at a phaseout schedule for all units and identify 18 particularly costly, inefficient, polluting and old units as 'no regret' options for phaseout by the end of 2023. Finally, we assess how South Korea could achieve this fossil phaseout by exploiting its domestic potential for renewables.

We find that South Korea has abundant renewable electricity potential. The potential is large enough to cost-effectively replace all current fossil electricity generation in the power sector, and also meet the additional electricity demand coming from the electrification of other sectors, either by direct electrification or the production of synthetic fuels. South Korea stands to benefit strongly from a fossil to renewables transition in the power sector.

[1] Power plants can consist of separate units with their own gas turbines.

Policy context

South Korea has committed to reaching carbon neutrality by 2050 (South Korean Government, 2021). To support this goal, South Korea updated its Nationally Determined Contribution (NDC) in 2021, aiming to cut greenhouse gas emissions to 40% below 2018 levels by 2030 (Republic of Korea, 2021). While this is an improvement on the previous target, it remains inconsistent with the Paris Agreement's 1.5°C temperature limit. If all countries pursued this level of ambition, it would lead to approximately 3°C of warming (Climate Action Tracker, 2022). To align with 1.5°C, South Korea would need to cut emissions by 62% by 2030 (range of 54-68%) (Climate Analytics, 2020a). More ambitious policies and action are therefore urgently needed.

South Korea is one of the world's largest importers of fossil gas. Its economy was particularly affected by spikes in global gas prices resulting from Russia's illegal invasion of Ukraine. Electricity prices were put up three times in 2022 by the state-owned energy company KEPCO, followed by a record 9.5% increase on 1 January 2023 (Reuters, 2022). The energy crisis has also contributed to growing inflation, which peaked at 6.3% in July 2022 (Stangarone, 2023). In response to these challenges, recently elected President Yoon Suk-yeol has redirected government policy, scaling back the previous administration's target of 30% renewable electricity generation by 2030 and instead focusing on nuclear power generation (Djunisic, 2023).

This change in policy direction is reflected in the 10th Basic Plan for Electricity Supply and Demand (10th BPESD), which was finalised in January 2023 (Ministry of Trade Industry and Energy, 2023). The plan is updated every two years and summarises the country's climate and energy policies for the power sector. The 10th BPESD can be summarised in three key areas.

1. **Slow and insufficient fossil phaseout.** Under the 10th BPESD, fossil fuels will provide a declining share of electricity generation. In 2021, coal and gas provided over 60% of power in South Korea. This share would fall to 43% by 2030, and by 2036, fossil fuels would still provide 24% of total electricity generation. Of this, 14.4% would be coal-fired generation, with fossil gas providing 9.3%. While the energy transition is moving in the right direction, the pace is not sufficient to deliver on the Paris Agreement's 1.5°C limit. Recent analysis has highlighted that coal would need to exit the power system by 2028-2029 for South Korea to align with 1.5°C (Carbon Tracker Initiative (CTI) et al., 2021; Climate Analytics, 2020b). The plan also includes proposals to convert 14 GW of coal-fired power stations to gas and build 9 GW of new gas-fired power stations. In 2021, gas' share of power production grew to 31%, while renewables increased only marginally to reach around 6%. Despite such expansions, gas should not be considered a bridging fuel in the energy transition.
   At the global level, energy pathways consistent with the Paris Agreement display rapid reductions in fossil gas generation, with gas effectively phased out by 2035 in OECD countries (Climate Analytics, 2022a).

2. **Large-scale reliance on nuclear generation.** The 10th BPESD represents a strong pivot towards nuclear as the key technology for the future South Korean power sector. Under the plans, which were released alongside the country's NDC in 2021, nuclear would provide 24% of electricity generation in 2030 (Ministry of Trade Industry and Energy, 2021a). Under the 10th BPESD, this share is increased to 32%, with a 2036 target of nuclear providing 35% of all electricity generation (Lee, 2023). There are plans to build at least five new reactors by 2033, as well as continued operation of 12 existing reactors.

3. **A reduced role for renewables.** As the 10th BPESD pivots towards nuclear, it does so at the expense of renewables. The 2030 target for renewables was downgraded from 30.2% of electricity generation to 21.6%. This is far less ambitious than the country's enhanced NDC, which set a 2030 renewables target of 30.3% (Ministry of Trade Industry and Energy, 2021a). By 2036, renewables would be providing only 30.6% of power supply under the 10th BPESD – essentially pushing back the previous renewables target contained in the NDC plan by six years.

South Korea has a range of other policies that are relevant to the role of fossil gas in the power sector. Two key areas (the role of hydrogen/ammonia, and the Korean green taxonomy) are highlighted below.

South Korea plans to use hydrogen and ammonia in the power sector to substitute for fossil fuels. By 2036, these fuels would provide 7% of electricity generation under the 10th BPESD (Lee, 2023). But according to the 1st Basic Plan for Hydrogen Economy Implementation, up to 50% of total hydrogen production in 2030 would be grey and blue hydrogen (Ministry of Trade Industry and Energy, 2021b). These are not carbon-free.

In December 2021, the Korean government also announced that fossil gas power plants that produce emissions below 340 gCO_2/kWh would be temporarily classified as "transition" investments (Tachev, 2022). This was ostensibly to facilitate a move away from coal-fired generation on the net-zero transition. This could lock in further fossil gas investments, at a time when fossil gas generation needs to be reduced to zero, risking large-scale asset stranding.

The 10th BPESD sets South Korea on a path of falling fossil generation. This is to be welcomed, but it is the pace, as well as direction, of the energy transition that matters. Here South Korea is still lagging behind what would be needed for 1.5°C compatibility, with a coal phaseout date set at 2050, and no clear phaseout date yet set for fossil gas. At the same time, South Korea is relying heavily on nuclear to drive fossil fuels out of the energy mix. By following this path, South Korea risks overlooking its abundant and cost-effective domestic renewable potential. In the analysis that follows, we therefore focus on how South Korea can accelerate the pace of its fossil phaseout to align with the 1.5°C limit, and how domestic renewables deployment can help achieve this goal.

Developing a 1.5°C compatible pathway for fossil gas

This report uses the latest 1.5°C compatible pathways as assessed by IPCC AR6 (IPCC, 2022) to define a 1.5°C compatible power sector transition for South Korea, and within this, determine a Paris-compatible phaseout schedule for fossil gas. It updates and further refines the methodology and results that were published in 2022 (Climate Analytics, 2022b). For a full description of our phaseout schedule methodology for fossil gas, see Appendix A.

Selecting and downscaling pathways for analysis

This report uses a subset of 21 pathways to define a 1.5°C compatible power sector transition. These pathways were all included in the IPCC AR6 database, which provides the latest evidence on global mitigation pathways (Byers et al., 2022).

Pathways are selected based on compatibility with the Paris Agreement, sustainability criterion and data availability. More specifically, all 21 pathways:

1. are compatible with Article 2.1 of the Paris Agreement, holding warming to “well below” 2°C and limiting warming to 1.5°C with no or low overshoot (< 0.1°C).

2. display power sector transitions in South Korea which are compatible with achieving net zero greenhouse gas emissions by 2100. They thereby align with Article 4.1 of the Paris Agreement, which sets out the aim to achieve a balance of sources and sinks in the second half of the century.

3. avoid unsustainable levels of carbon dioxide removal (CDR), using thresholds defined by the literature (Fuss et al., 2018).

4. provide the necessary data to enable downscaling to the national level.

For more details on the scenario filtering approach, see Appendix A1.

These IAM pathways do not provide data at the national level, but instead provide data for a set of "macro regions" which represent larger geographical groupings of countries. In the IPCC AR6, data is provided at the R10 level, representing the world by ten major regions.[2] It is therefore necessary to downscale the pathways from the regional level to the national level.

This is done using an emissions intensity convergence method (Gidden et al., 2019; van Vuuren et al., 2007). In this method, the carbon intensity of the power sector in each country (in CO_2/GDP) in the macro-region is calculated in 2019. Future carbon intensities are then projected by assuming that these intensities will converge to the macro-region average by 2100. Combining these projected intensities with GDP projections for each country gives the resulting CO_2 emissions trajectory for the power sector at a national level.

We also downscale the electricity mix in these IAM pathways to the national level. This allows us to explore how fossil, nuclear and renewable generation develop over the coming decades to meet future electricity demand growth while eliminating fossil fuels from the South Korean power sector. To do this, the downscaling tool SIAMESE was applied (for more details, see Appendix A2). SIAMESE provides a cost-effective allocation of energy consumption at the national level, mirroring the internal logic of IAMs.

Calculating a 1.5°C compatible emissions envelope for the power sector

Having downscaled the power sector transition from the regional level to South Korea, we then calculate a 1.5°C compatible emissions envelope for electricity generation. This is the level of future emissions that the South Korean power sector needs to fall within, if it is to be aligned with 1.5°C.

To calculate this envelope, we split the emissions distribution of all downscaled 1.5°C pathways into percentiles. We do not consider pathways above the median of the emissions distribution as compatible with the 1.5°C limit. This is because if one country were to follow a higher percentile in the distribution (e.g., the 90th percentile), this would require a corresponding increase in effort from other countries to ensure 1.5°C compatibility at the global level. For this reason, we take the 0-50th percentiles of the distribution to form the 1.5°C compatible power sector emissions envelope for South Korea. We then focus on the median of this 1.5°C compatible range, which is the 25th percentile of the overall distribution of pathways. To correct for the model-related bias in the ensemble, **model-weighted percentiles** were used in this analysis (for more details see Appendix A3).

[2] These ten world regions are China+, India+, Pacific OECD, Rest of Asia, Middle East, Africa, Europe, Latin America, North America and the Reforming Economies. South Korea is generally found within the Pacific OECD, Rest of Asia or China+ macro region in these models.

1.5°C compatible emissions pathways for the power sector

Figure 1 shows the resulting 1.5°C compatible emissions envelope for the South Korean power sector, with the median of this range shown in orange. To align with 1.5°C, South Korean power sector emissions need to fall rapidly this decade and should reach zero between 2030 and 2037. The median pathway reaches this milestone in 2034. Achieving this will require the displacement of all fossil-based electricity generation, including fossil gas.

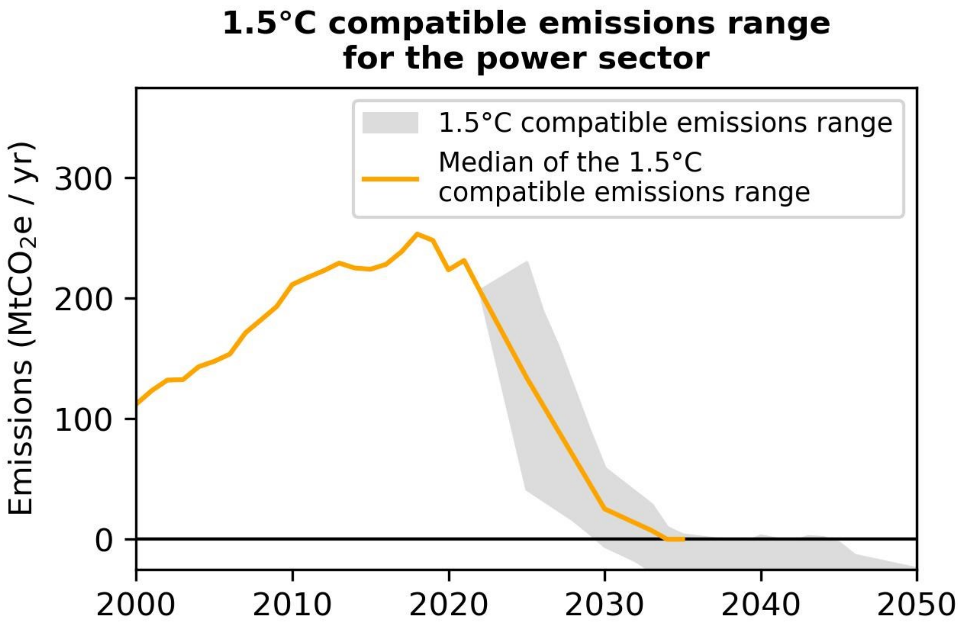

Figure 1: 1.5°C compatible power sector emissions for South Korea.

Gas phase-out requirements in the power sector

Having produced a 1.5°C compatible emissions envelope for the South Korean power sector, we then explore the coal and gas phase-out schedules that would comply with this envelope.

We assume that coal-fired power generation in South Korea is phased out by 2029, in line with previous research which explored a 1.5°C compatible coal phase-out in the sector (Climate Analytics, 2020b). Figure 2 shows the emissions from this coal phase-out in black, with the remaining emissions headroom for gas shown in different shades of green (for different quantiles of the distribution).

The majority of the 1.5°C compatible emissions budget in the power sector is consumed by coal-fired power, even as its generation is rapidly reduced to zero by 2029. There is therefore very limited room for continued fossil gas generation, which needs to exit the power sector in the early 2030s.

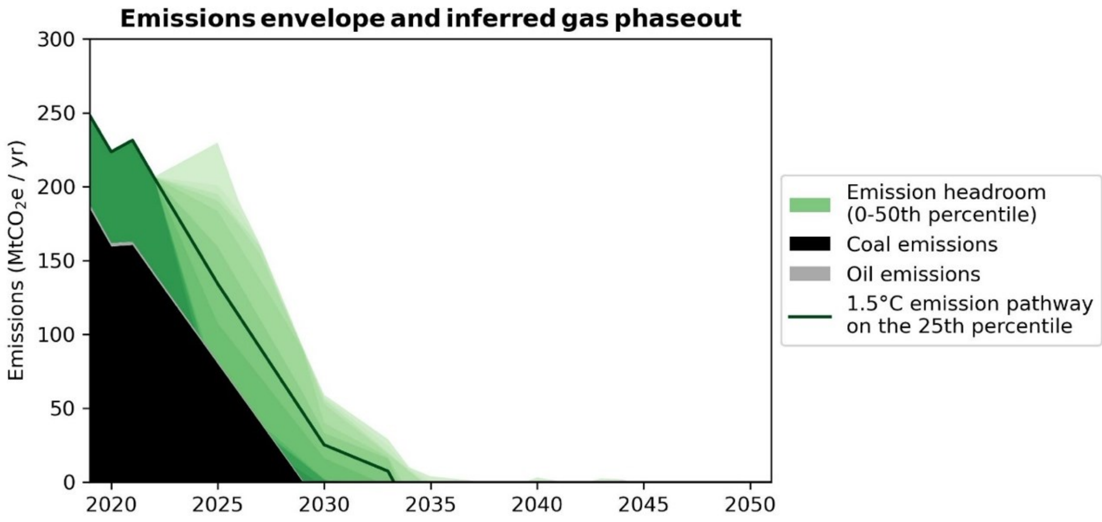

Figure 2: Remaining emissions for gas under a 2029 coal phaseout date.

Figure 3 shows the resultant 1.5°C compatible pathway for fossil gas in the power sector. The emissions headroom for fossil gas is shown in the first panel, with resultant 1.5°C compatible electricity generation in the second panel.[3] In the central pathway, fossil gas generation begins to decline immediately from 2022 onwards and is phased out by 2034. In the most ambitious pathways, fossil gas generation is phased out even earlier, by 2030, and in all pathways, gas exits the power sector by 2037 at the latest.

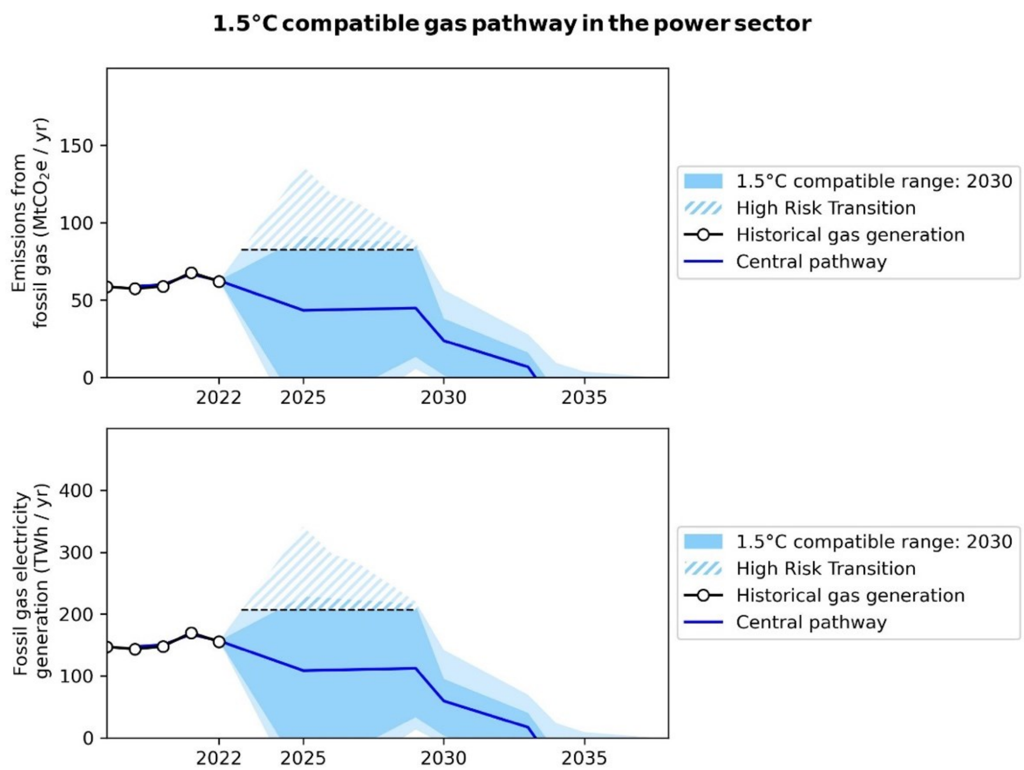

Figure 3: 1.5°C compatible phase out of fossil gas in the power sector.

[3] We estimate that the fossil gas fleet in South Korea in 2023 has an average emissions intensity of 399gCO_2/kWh – this factor is used to convert between emissions and generation in this analysis. This value is calculated using unit-level data provided to Climate Analytics via SFOC.

Moving to higher percentiles of the 1.5°C compatible range increases the near-term scope for fossil gas generation. However, it is important to note that:

1. The long-term future of fossil gas remains unchanged, with gas generation peaking in 2025 and exiting the power system by 2037 across all percentiles.

2. This near-term increase in fossil gas generation is dependent on a rapid and immediate phase-out of coal in the power sector starting in 2022. Even if the coal phaseout is delayed by just two years (starting in 2024), this near-term headroom for gas generation is substantially curtailed.

3. The emissions envelope produced here is based on downscaling IAM pathways. These IAM pathways assume the successful rollout of bio-based electricity with carbon capture and storage (BECCS) in the power sector. The viability of BECCS deployment in South Korea is likely to be very limited, due to a range of factors including the availability of sustainable biomass resources (Song and Lim, 2022), access to CO_2 storage facilities (Grant et al., 2022), and the technological maturity of BECCS (IEA, 2022a). If BECCS is not successfully deployed, then fossil-based emissions reductions in the power sector would have to be accelerated, which would further reduce the room for near-term increases in fossil gas generation.

4. Any expansion of fossil gas-fired power generation beyond existing capacity would be a recipe for substantial asset stranding and a disruptive and more costly transition.

Gas power generation could be slightly increased by greater utilisation of existing capacity. For example, if all units were to operate at the average capacity factor of the current gas fleet (43%) or above, then total generation in the South Korean gas fleet could be increased by 43 TWh to reach 206 TWh. We therefore label any generation above this level as a "high risk" transition, as it would require investments in new gas-fired power plants. Research has shown that existing fossil fuel infrastructure (including fossil gas power plants) could already jeopardise the 1.5°C temperature limit (Tong et al., 2019). In this context, new investments in fossil gas generation should be avoided as a clear policy priority.

However, we highlight again that any increase in fossil gas generation (whether from the existing gas fleet or by building new gas-fired power stations) is contingent on an immediate and rapid coal phase-out and successful deployment of negative emissions technologies. It will also exacerbate South Korea's dependency on expensive and volatile liquefied natural gas (LNG) import markets. As such, any growth in gas-fired power generation should be seen as risky and sub-optimal policy.

The initial 1.5°C compatible fossil gas pathway shown in Figure 3 is not linear. For example, after the coal phaseout in 2029, no further emission reductions can be achieved from coal-fired power stations, and emissions reductions from the gas fleets then need to be accelerated.

In reality, a more orderly linear transition would minimise asset stranding and help policymakers and utilities plan for the transition to renewables. We therefore developed a simpler, linear 1.5°C compatible pathway for fossil gas generation in the power sector.

To develop this pathway, we take two key data points from the downscaled pathways:

1. In the central 1.5°C compatible pathway, fossil gas exits the power sector in 2034. This is taken as the target phase-out date to align with the Paris Agreement.

2. In the central 1.5°C compatible pathway, cumulative emissions from fossil gas from 2022 onwards are 419 $MtCO_2$. Any linearised schedule must ensure that cumulative emissions from fossil gas remain within this budget.

In the linearised pathway, emissions from fossil gas peak in 2023 and decline linearly to zero by 2034. Cumulative CO_2 emissions from the gas fleet are 409 $MtCO_2$. This phaseout schedule is shown in Figure 4 and is used in the rest of the analysis. In this pathway, emissions from fossil gas fall by 5.9 $MtCO_2$/yr, with generation falling 14.9 TWh/yr between 2023 and 2034.

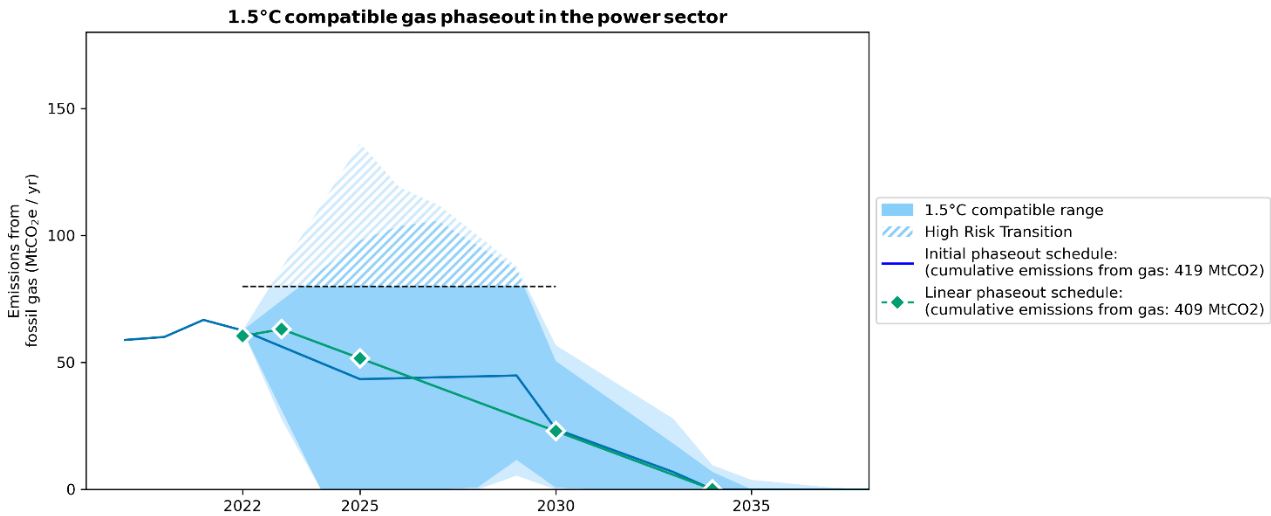

Figure 4: A linear 1.5°C compatible pathway for fossil gas generation.

1.5°C compatible unit level phaseout schedule

Having developed a 1.5°C compatible emissions pathway for fossil gas in the South Korean power sector, we now determine a phaseout schedule which complies with this emissions pathway. This provides a unit-by-unit order in which to retire fossil gas in South Korea. There are a range of relevant criteria that could be used to create this schedule. We perform a multi-criteria analysis which considers the electrical efficiency, running costs, health impacts, start year and heat contribution of each gas unit when determining the phaseout date. This ensures that a range of key considerations are accounted for in the analysis.

Gas power fleet

At the end of 2023, the South Korean fossil gas power fleet will consist of 101 individual units which are distributed across 61 sites[4] (there are 4 units due to come online during the course of 2023: Yeoju, Naepo Green Energy, Yangsan CHP and Gimpo CHP)[5]. To comply with the previously determined 1.5°C compatible pathway, all of these units need to be shut down by 2034. Beyond 2023, there are multiple gas units which are under consideration for development by the government. This includes 9.3 GW of new fossil gas units, and 14.1 GW of ageing coal-fired units which would be converted to run on fossil gas. However, as fossil gas generation needs to start declining from 2023 onwards, there is no scope for new gas-fired units to come online after 2023. For more detail on the coal-to-gas conversion projects, and their associated climate and financial risks, see Box 1.

Key indicators that are useful for comparing gas power plants are:

- Electrical efficiency of the unit
- The running costs of the unit in KRW/kWh
- The air pollution impacts of each unit (measured in terms of associated health risks produced per kWh)
- The start year of operation
- Whether a plant is a combined-cycle power plant (CC) or a combined heat and power plant (CHP)

[4] As previously noted, an individual power plant (a specific site) can contain multiple units, each capable of generating independently and with differing characteristics. We conduct our analysis at the unit-level rather than the plant level.
[5] The power plant data used in this report was provided by SFOC, which obtained it from the National Assembly.

The location of these 101 units, and their efficiency, running costs, air pollution impacts, start year and technology type are shown in Figure 5. This helps visualise the South Korean fossil gas generation fleet. For a detailed description of these indicators, please refer to B1: Calculation of indicators in the Appendix.

In general, the power plant sites are located close to population centres. A particularly large concentration of sites can be observed in the wider Seoul region, spanning across Incheon and Gyeonggi-do. This area is also where the most costly, most polluting, most inefficient and oldest units are located.

Box 1: Coal-to-gas conversions in South Korea

South Korea aims to reduce its reliance on coal in the coming decades. However, rather than retiring ageing coal plants, South Korea intends to convert many of them to run on LNG. There is over 14 GW of coal-fired capacity (28 units) that are due for conversion to LNG between now and 2036 (Ministry of Trade Industry and Energy, 2023). Coal-to-gas conversions display multiple risks to South Korea's energy transition.

First, such conversions present a **climate risk.** Fuel switching from coal to gas may reduce CO_2 emissions from the power plant stack, but this also delays the deployment of zero-emissions electricity generation, which is required to achieve a clean power sector. These gas plants would operate for multiple years into the future – with the committed emissions from future gas generation potentially eliminating any immediate savings from a coal-to-gas conversion (Shearer et al., 2020), particularly when the upstream methane emissions associated with gas extraction are accounted for.

Secondly, coal-to-gas conversions present a significant **financial risk.** Multiple lines of evidence have highlighted that renewables are outcompeting fossil fuels across many locations in the world (IRENA 2021, Carbon Tracker Initiative 2020, IPCC 2021). This finding is confirmed by detailed analysis of South Korea's renewable potential, and the running cost of the fossil gas fleet (see Techno-economic potential of Korea's renewable energy sources). Moving from coal-to-gas instead of coal-to-clean will therefore lock-in reliance on expensive and uncompetitive forms of generation, while the cost of renewables continues to plummet. One recent analysis found that coal-to-gas conversions represent a $60 billion stranded asset risk for South Korea (Carbon Tracker Initiative, 2020).

Gas-fired generation needs to peak in 2023 and start to decline immediately. In this context, and due to the **climate and financial risks** associated with coal-to-gas conversions, we argue that to align with 1.5°C, all coal-to-gas conversions should be halted immediately. As such, coal-to-gas conversions are excluded from the unit-level phaseout schedule, with the assumption that they do not enter into operation in the first place.

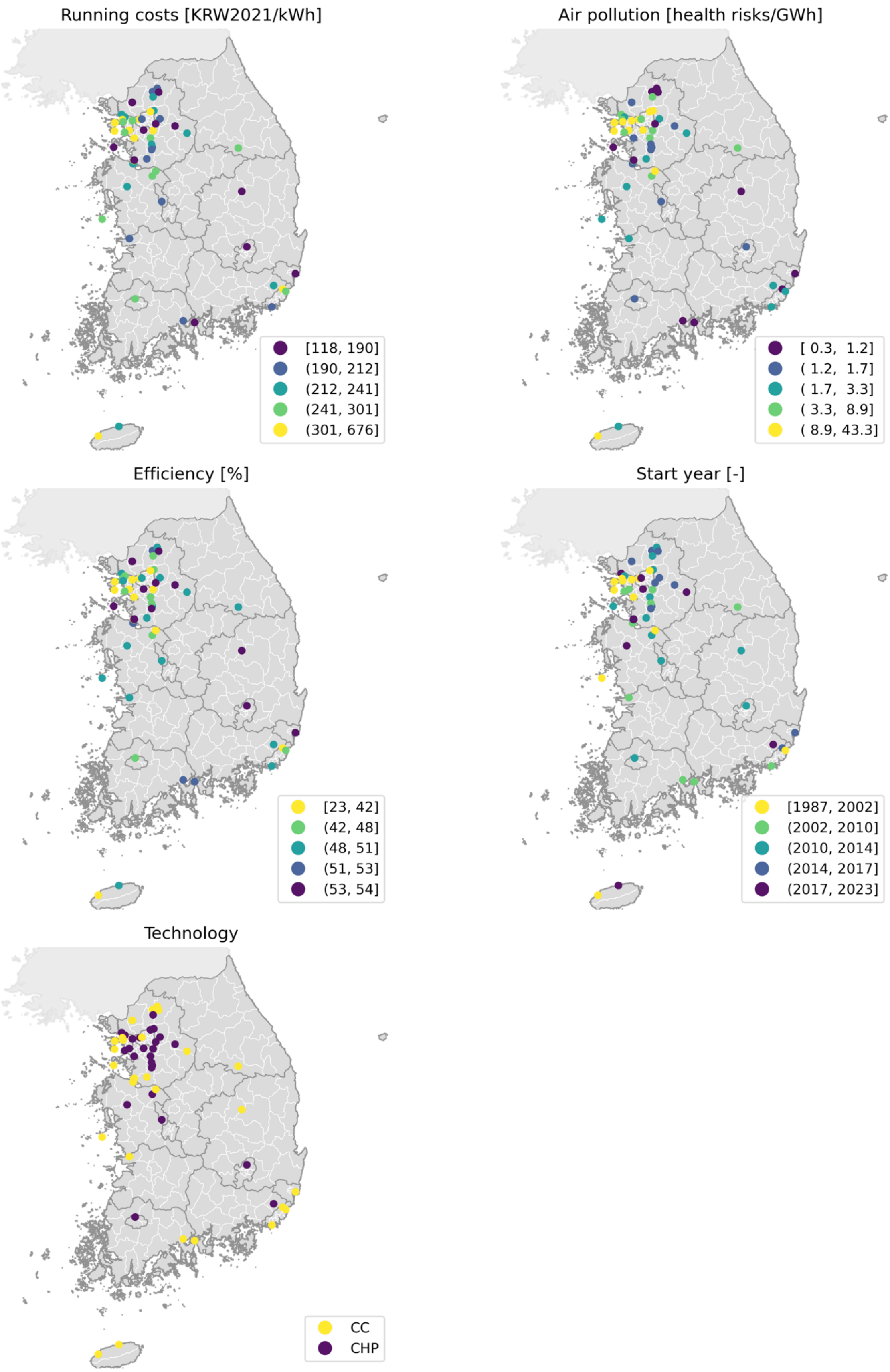

Figure 5: Regional visualisation of power plant sites and their key indicators (given as a mean if a plant site consists of several units).

There are a number of outliers in terms of efficiency, running costs and air pollution, indicating particularly inefficient, costly and polluting units, as can be observed in Figure 6. These outliers are both combined-cycle and combined heat and power units; however, the tail end of the outliers (i.e., the worst performing units across each indicator) is mostly constituted of combined heat and power units.

The oldest gas-fired power unit in South Korea started operating in 1987, but the median unit started operating in 2012, and a number have come online since the Paris Agreement was signed.

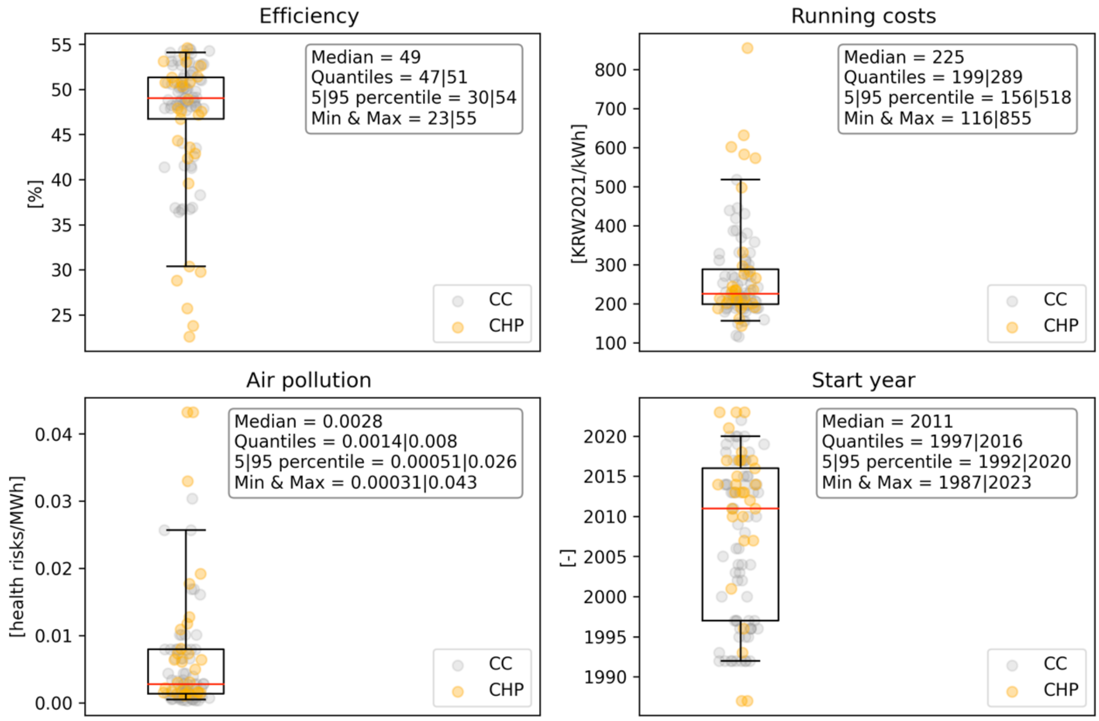

Figure 6: Statistical overview of fossil gas power unit indicators.

For each indicator, the median (red line), interquartile range (box) and 5-95th percentile range (whiskers) across the 101 units are shown. Dots which fall outside the 5-95th percentile range can be seen as outliers in the gas fleet.

An investigation of the correlation between the indicators provides further insights. Figure 7 shows that there is a clear negative correlation between efficiency and running costs and health risks, while there is a positive correlation between efficiency and unit age. This shows that inefficient units are also the ones with the highest running costs, are associated with the greatest health risks from air pollution, and are generally older. These units may be priorities for early phaseout across multiple dimensions.

To fully determine the phaseout schedule, we perform a full multi-criteria analysis.

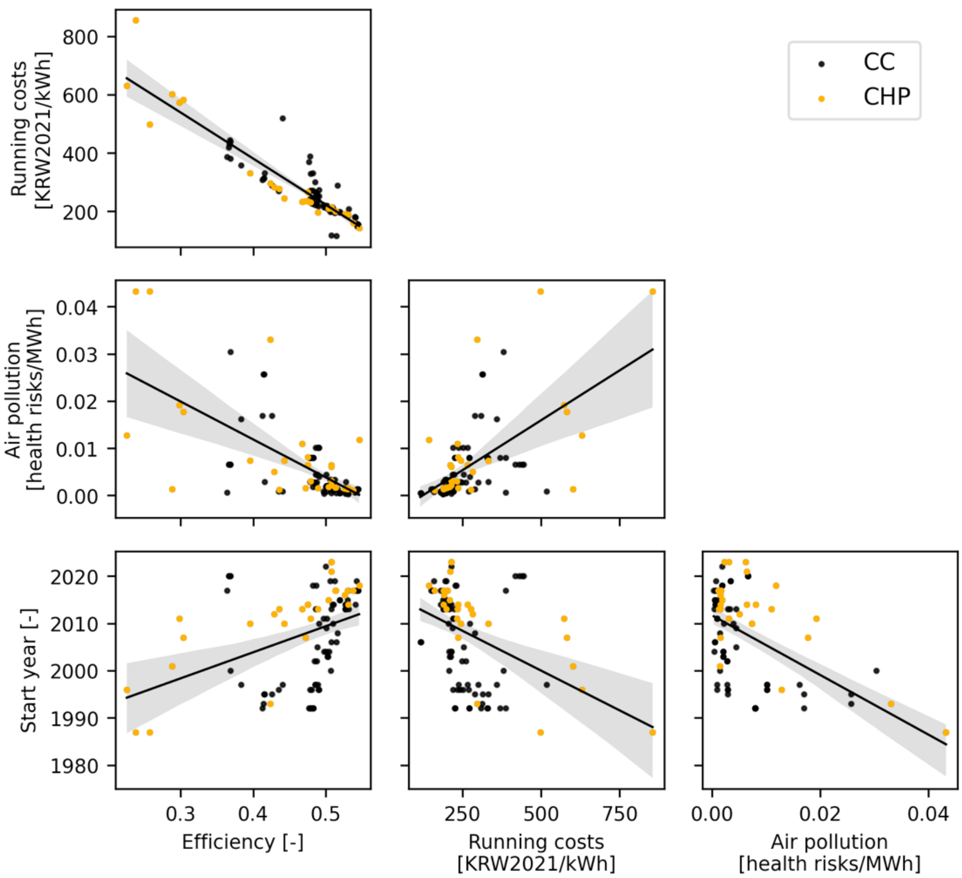

Figure 7: Correlation between different indicators for the fossil gas units.

Two distinct phaseout schedules

This report produces two distinct phaseout schedules, which represent the different potential perspectives of national and regional policymakers on how to prioritise gas units for phaseout. In both perspectives, all of the above indicators are considered when determining the phaseout schedule, to give a multi-criteria analysis of the fossil gas phaseout. However, the indicators are prioritised differently across the two perspectives.

In each perspective, indicators are assigned different priorities, from highest priority to lowest priority. Each unit is given a score of 1-5 for each indicator, with a 1 representing poor performance in the indicator (and hence priority for phaseout), while a 5 represents comparably better performance in the indicator, and hence a later phaseout date.

The units are then ordered, based on the highest priority indicator. Any tie-breaks are then settled by the second indicator, with remaining tie-breaks settled by the third, fourth and fifth indicator in turn. For a more detailed description of the applied method, see Appendix B2: Method of the multi-criteria decision analysis.

The first phaseout schedule is set up with a cost focus, aiming to maximise the economic benefits of the fossil gas phaseout. The second phaseout schedule aims to maximise the health benefits of the fossil gas phaseout, by reducing air pollution as quickly as possible. This is described as a health focus. The order of priority in each perspective is shown in Table 1.

Table 1: Order of preference of the indicators in the two phaseout schedules.

Order of preference	Cost focus	Health focus
1	Running cost	Air pollution
2	Start year	Efficiency
3	Technology	Running cost
4	Air pollution	Start year
5	Efficiency	Technology

The cost-focused perspective aims to maximise the economic benefits of the fossil gas phaseout. The first indicator is running cost – so that the most expensive units with the highest running costs are phased out first. The units are then sorted by the starting year of operation, with older units being phased out before newer units. This helps ensure that new units can return their upfront investment and, in this way, reduces the risk of stranded assets. As a third priority, the technology type (whether CC or CHP) is considered to reflect the additional services CHP units provide to the system by providing domestic heat. Where the cost and age of units are similar, this phaseout schedule prioritises phase out of the CC plants over the CHP plants. Reducing air pollution is associated with considerable economic co-benefits due to improved health outcomes and is given a priority of 4. Finally, the efficiency of the units is added as a simple tie breaker, noting that there is a strong correlation between efficiency and running cost across the units.

For the health-focused perspective, units with the greatest health risks from air pollution per MWh of electricity generation are prioritised for phaseout. The second priority is given to the efficiency of the unit. Units which are less efficient will require more fossil gas extraction to provide a given amount of electricity. The running cost, start year and technology type are added, in the same order as in the cost-focused perspective, as tie breakers.

The final sorted unit tables, which show how each unit performs across the five indicators, and sort the 101 units into their phase out order, can be found in Appendix B3: Additional outputs of the multi-criteria decision analysis (Figure B3 and Figure B4). Figure 8 shows the resulting unit-level phaseout schedule for the two case studies as well as the mean phaseout year.

Phaseout schedules

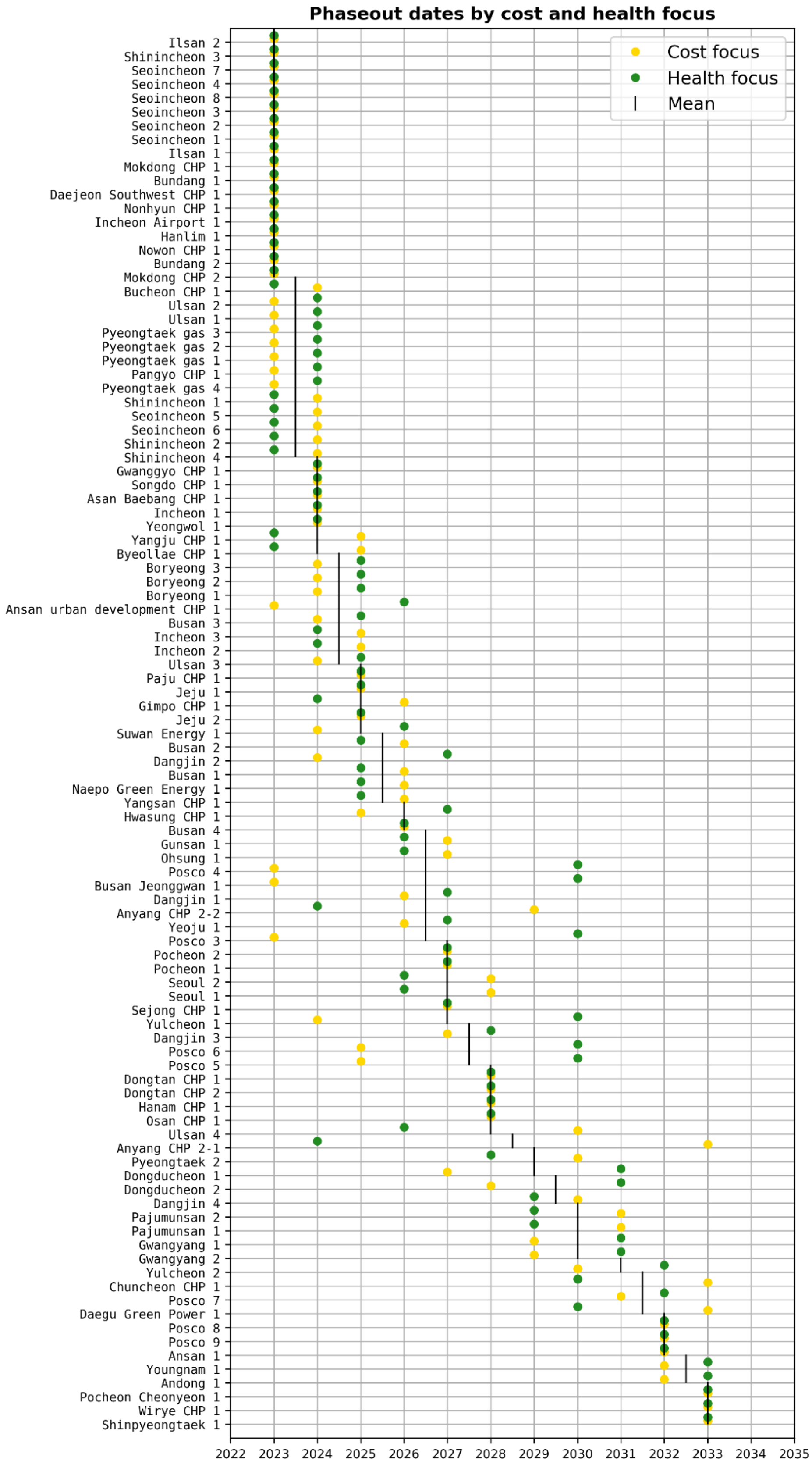

Figure 8: Unit-level phaseout schedules for the different case studies and the resulting mean phaseout year for each unit.

There is close agreement between the two perspectives on which units should be phased out first, with 18 units phased out in 2023 in both the cost-focused and the health-focused phaseout schedule. That is, regardless of which preferences are used to determine the phaseout schedule, there is a set of ‘no regret' power units which are a priority for immediate phaseout in both cases. This is due to the correlation between the underlying indicators. There are several units that are both expensive to run, inefficient, older, and responsible for greater levels of air pollution. These units are clear priorities for phaseout in the coming months.

In general, there is a high level of agreement between the two perspectives. On average, the date of phaseout for each unit differs by only 1.5 years between them. This provides greater confidence in the robustness of the phaseout schedule presented here. There are only nine units where the two perspectives suggest phaseout years that differ by more than four years. For these specific units, careful consideration of policymaker preferences is needed to determine the final phaseout date.

A list of the 18 units which should be phased out within 2023 to align with the 1.5°C compatible gas pathway across both case studies is given in Table 2. These units are clear priorities for an immediate phaseout and replacement with renewable generation. This will bring clear benefits in terms of CO_2 emissions, running costs and air pollution levels.

Table 2: Units which should be phased out in 2023 when adhering to a 1.5°C compatible emissions pathway for fossil gas across both case studies.

<table>
<tr><th>Plant name</th><th>Unit</th><th>Efficiency</th><th>Running costs</th><th>Air pollution</th><th>Start year</th></tr>
<tr><td>Nowon CHP</td><td>1</td><td rowspan="11">Worst 20% of units</td><td rowspan="7">Worst 20% of units</td><td rowspan="18">Worst 20% of units</td><td>1996</td></tr>
<tr><td rowspan="2">Mokdong CHP</td><td>1</td><td>1987</td></tr>
<tr><td>2</td><td>1987</td></tr>
<tr><td>Daejeon Southwest CHP</td><td>1</td><td>2011</td></tr>
<tr><td>Nonhyun CHP</td><td>1</td><td>2007</td></tr>
<tr><td>Incheon Airport</td><td>1</td><td>2000</td></tr>
<tr><td>Hanlim</td><td>1</td><td>1997</td></tr>
<tr><td>Bundang</td><td>1</td><td rowspan="2">Worst 20-40% of units</td><td>1992</td></tr>
<tr><td rowspan="2">Ilsan</td><td>1</td><td>1993</td></tr>
<tr><td>2</td><td>Worst 20% of units</td><td>1995</td></tr>
<tr><td>Bundang</td><td>2</td><td>Worst 20-40% of units</td><td>1995</td></tr>
<tr><td rowspan="6">Seoincheon</td><td>8</td><td rowspan="6">Worst 20-40% of units</td><td rowspan="4">Worst 20% of units</td><td>1992</td></tr>
<tr><td>2</td><td>1992</td></tr>
<tr><td>3</td><td>1992</td></tr>
<tr><td>1</td><td>1992</td></tr>
<tr><td>4</td><td rowspan="3">Worst 20-40% of units</td><td>1992</td></tr>
<tr><td>7</td><td>1992</td></tr>
<tr><td>Shinincheon</td><td>3</td><td>Worst 40-60% of units</td><td>1996</td></tr>
</table>

Figure 9 displays the phaseout schedule, taking the mean phaseout year across the two perspectives, and distinguishing between the different administrative regions of South Korea.

There are a number of units in the regions of Gyeonggi-do and Incheon that are phased out in the first few years of the phaseout schedule, as they have the greatest health risks from air pollution and are also the most costly to run. Over time, as units are phased out, the average air quality of population centres rises.

The number of units phased out per year in each phaseout schedule is shown in Figure *10*. In both cases the phaseout schedule is front-loaded, with more units and capacity being retired in 2023-2025 than in later years. This is despite a linear phaseout schedule, with emissions falling by the same amount per year (5.9 $MtCO_2$/yr) across the 2023-2034 period.

The front-loaded schedule occurs because the initial units to be phased out are generally smaller – with a median capacity of 225 MW (compared to the median capacity of the whole fossil gas fleet of 450 MW). Phasing out smaller units first can distribute reductions in fossil electricity generation across different areas, making it easier to replace individual units with renewable alternatives and minimising grid constraints.

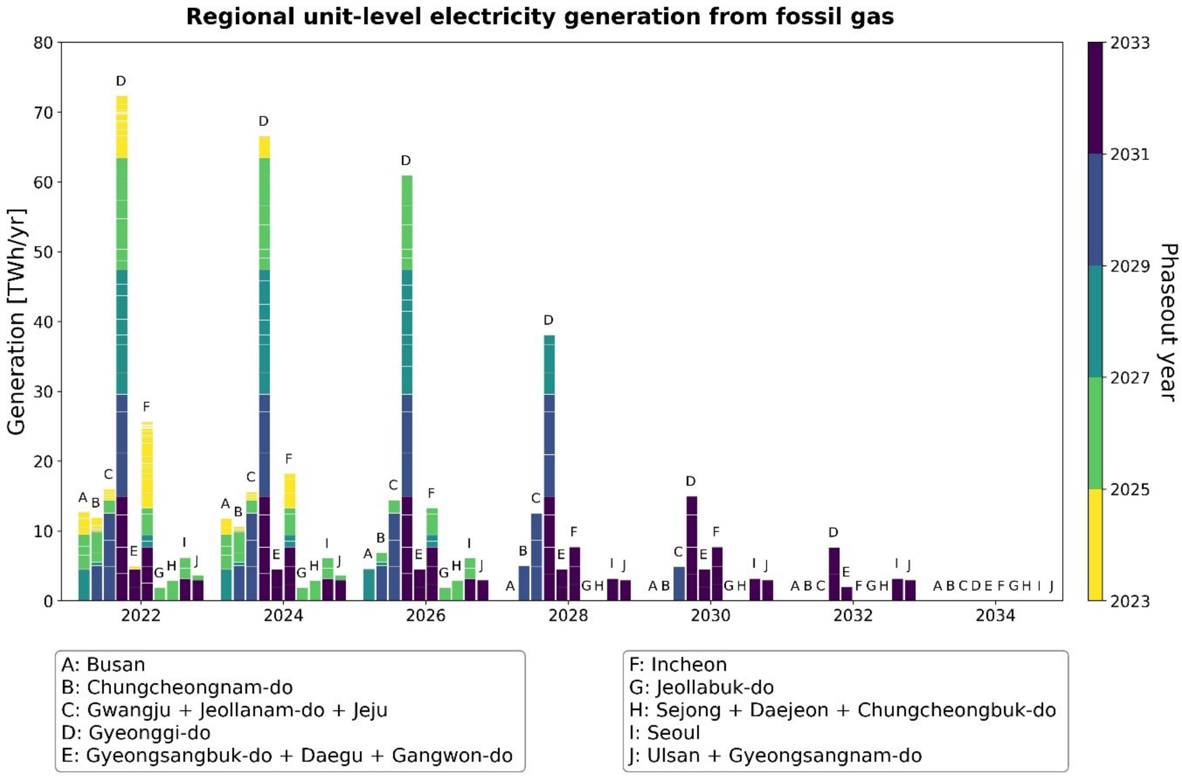

Figure 9: Phaseout schedule of fossil gas power plant units.

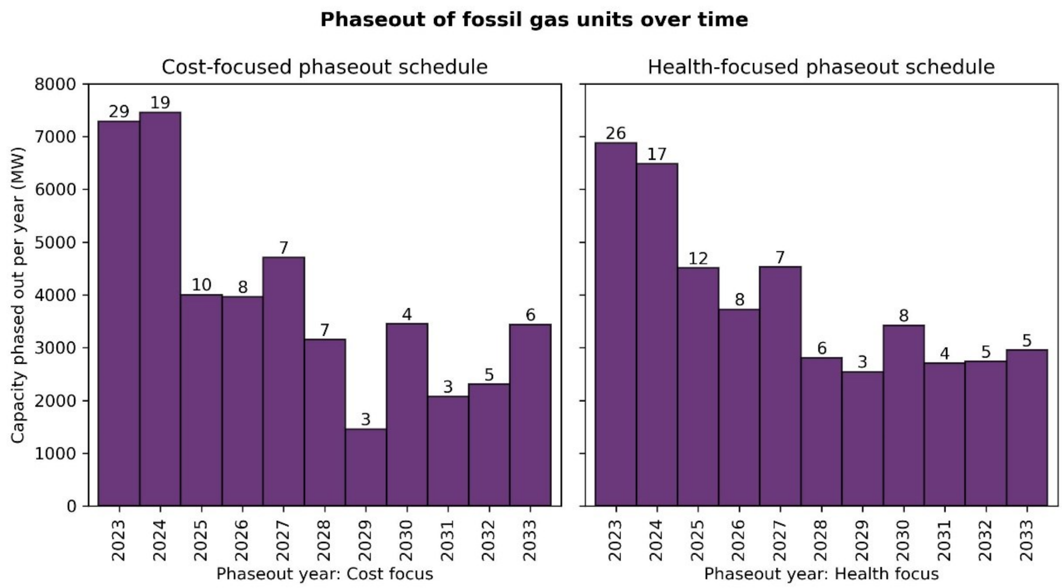

Figure 10: Distribution of the unit phaseout over time.

The numbers above each bar show the number of units retired in a given year.

Feasibility of renewable energy transition

This section demonstrates how South Korea can utilise its abundant renewable potential to achieve a fossil free power sector while meeting increased future electricity demand.

Techno-economic potential of Korea's renewable energy sources

To explore how South Korea could achieve the phase-out of coal and gas required in 1.5°C compatible pathways, we assess the technical potential of variable renewable energy sources (VRES) in South Korea, distinguishing between onshore wind, offshore wind, open-field PV, and rooftop PV. We apply temporally and spatially-resolved simulation models to capture the VRES dynamics and their spatial characteristics.

We first calculate the proportion of land and offshore area that is eligible for renewables deployment in South Korea. This is based on a range of exclusion criteria, including proximity to roads/airports, shipping routes, national protected areas and other considerations such as the elevation/slope of the area, among others. We then perform a placement simulation on the eligible land and offshore area, applying the latest wind speed and solar irradiance data, to quantify the level of generation that could be provided by each site, and at what costs. This approach allows us to have a robust assessment of the technical potential of VRES for each geographic location in Korea. To do this we use a range of globally gridded datasets, including recently published global forest management data (Lesiv et al., 2022). See the technical appendix for further details.

Table 3 shows the results of our renewable potential assessment, summarising South Korea's technical potential for onshore/offshore wind, open-field and rooftop PV, in terms of both capacity and generation. For the spatial distribution of this renewable potential, we refer to Figure C1 and Figure C2, which indicate the sites with strong wind and solar potential across eligible areas in South Korea.

Table 3: Korea's technical potential of VRES in capacity and generation terms.

Technology	Renewable potential: max capacity (GW_{el})	Renewable potential: max generation (TWh_{el})
Onshore wind	42	121
Offshore wind	870	3710
PV open-field	584	1050
PV rooftop	57	65
Total	**1553**	**4946**

The total onshore wind potential in South Korea is estimated at 42 GW. The technical potential of offshore wind is estimated at 870 GW including both fixed and floating foundations.[6] Even when applying a comprehensive set of exclusion factors and geospatial constraints, leading to low proportions of eligible land (see Figure C1), the results indicate a significant open-field PV potential in South Korea of over 500 GW. The PV rooftop capacity potential is estimated at 57 GW. Taken together, renewables could generate almost 5000 TWh annually in South Korea. For comparison, Table 4 shows the current coal- and gas-fired capacity and generation in South Korea in 2020. This indicates that South Korea has potential solar and wind resources that far exceed its current fossil-based generation.

Table 4: Current fossil fuel-based generation and capacity in South Korea (year: 2020).

Fuel	Capacity (GW_{el})	Generation (TWh_{el})
Coal	35	196
Gas	45	146

To illustrate the transition to renewables, and geographically identify where generation losses and gains would occur, Figure 11 shows the spatial distribution of residual load. The residual load is the total fossil generation in each region minus the region's renewable potential. A negative value means that there is greater renewable potential in the region than existing fossil generation, while a positive value means that current fossil generation in the region exceeds the localised renewable potential.

It is clear from Figure 11 that most regions in South Korea have more than enough renewable potential to replace existing fossil generation in the region. Although some populated regions across the coastal areas display a positive residual load, mismatches between the local demand and supply can be addressed via offshore wind installations, or through extension of the power transmission grid to transport electricity from high potential areas to load centres with less local potential for renewable electricity generation. Alternatively, green hydrogen produced from excess VRES generation in high potential sites can be used to satisfy the demand in those sites with missing local potential.

[6] Fixed offshore turbines installed up to the depth of 100m with floating foundations used for depths beyond up to 200m.

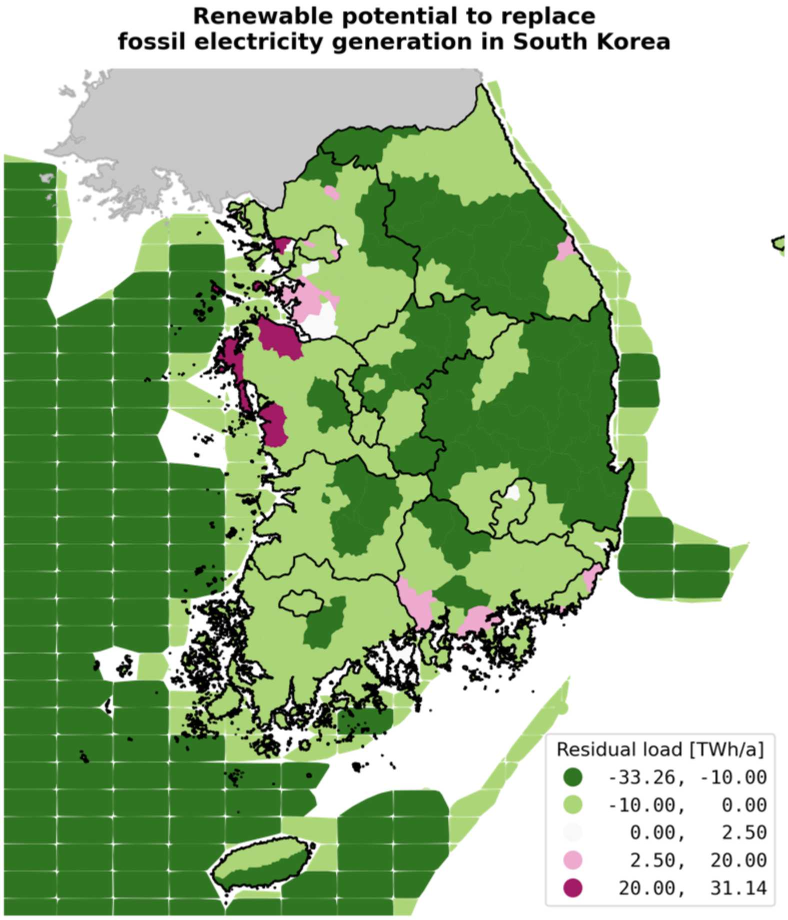

Figure 11: Spatial distribution of residual load (total annual fossil generation subtracted by the renewable potential) in South Korea.

The renewable potential assessment also provides the levelised cost of electricity (LCOE) for individual units installed across eligible areas. Figure *12* shows the distribution of LCOEs for onshore and offshore wind, PV open-field, and PV rooftop. For the spatial distribution of LCOEs for different renewable technologies, see Figure C2.

Figure *12* shows that the fossil gas fleet in South Korea is more expensive to run than renewable alternatives. Switching to renewables would bring considerable economic benefits as well as emissions savings. The cheapest onshore wind LCOE is estimated at 30 KRW_{2021}/kWh, while the median cost is 72 KRW_{2021}/kWh. For offshore wind, the cheapest LCOE is estimated at 99 KRW_{2021}/kWh with a median of 167 KRW_{2021}/kWh. The lowest PV open-field LCOE is found at 54 KRW_{2021}/kWh, with a median of 60 KRW_{2021}/kWh.

We compare these LCOEs with the long run marginal costs of gas plants (see Figure *12*). The long run marginal costs for gas units ranges between 116 KRW_{2021}/kWh and 855 KRW_{2021}/kWh, with a median of 225 KRW_{2021}/kWh. The fossil gas fleet in South Korea is generally quite expensive, due mainly to the high cost of imported LNG. There is around 1000 TWh of renewable electricity generation which could be deployed with costs lower than every fossil gas unit in South Korea, and almost 4000 TWh which can be deployed at a cost less than the median fossil gas plant. This analysis does not include grid upgrade or storage costs – however we note that grid upgrades will be required to meet additional electricity demand, regardless of the transition to renewables. We also calculate the potential cost increase to wind and solar generation from the accompanying storage deployment, which is found to be minor (see following sections).

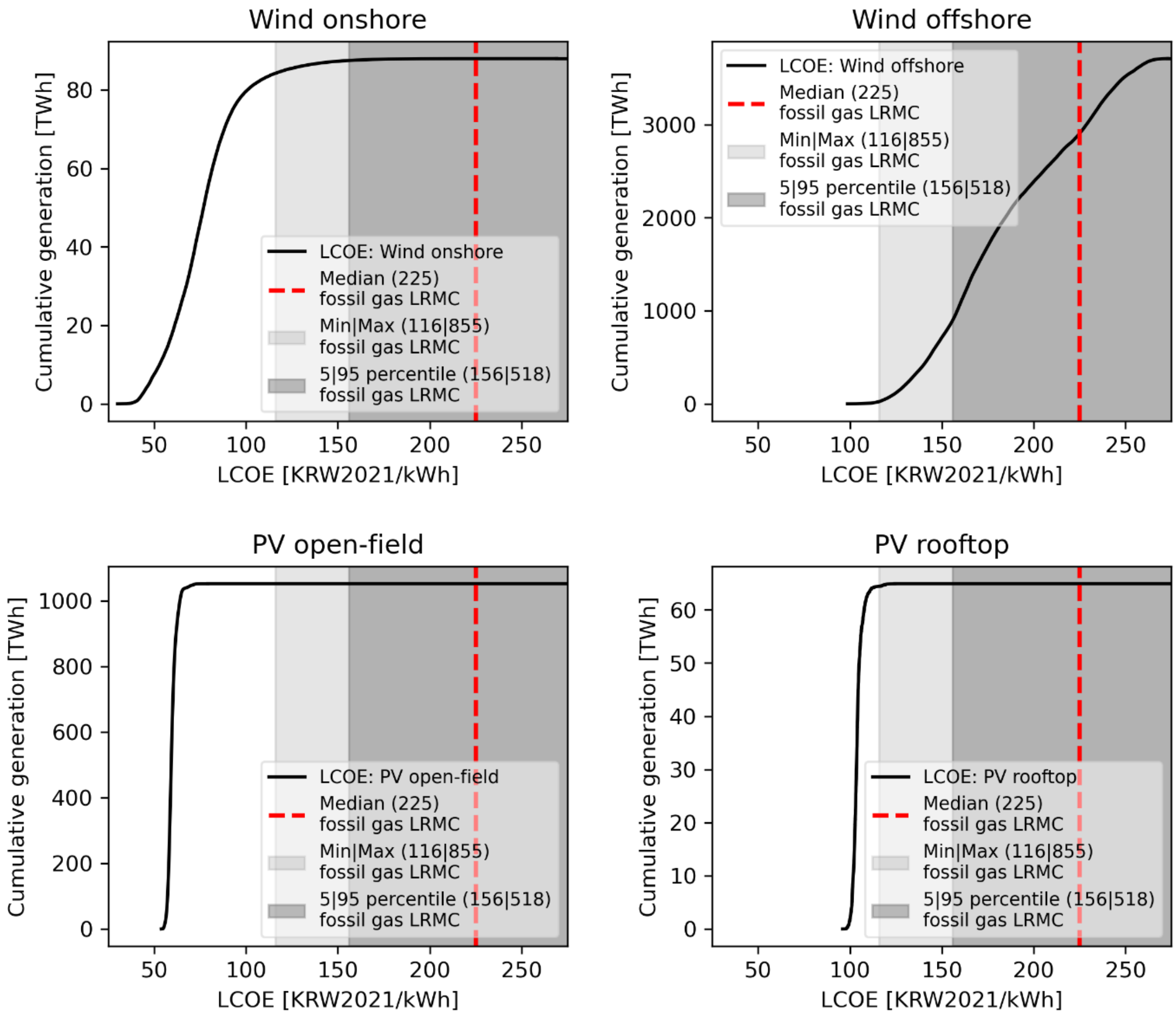

Figure 12: LCOE distribution of renewable technologies in South Korea.

The shaded area represents the range of gas plants' long-run marginal costs with the red dashed line showing the median of the range. Note: this is based on IRENA medium cost scenario assumptions for 2020 (see Appendix C: Nearby renewable energy resources).

Comparing the running costs of the existing gas-fired power generation fleet to the LCOE of new renewable generation allows us to understand the cost savings from a fossil-to-renewable transition. While the limitations of using LCOEs to understand the economics of power generation are well known, they remain a valuable proxy for understanding system dynamics and to give a first estimate of the cost savings of decarbonisation.

Retiring expensive fossil gas generation and replacing it with low-cost renewables could save South Korea 170 billion KRW_{2021} in running costs by 2034, relative to a scenario in which gas generation remains fixed at 2023 levels. In 2021, we estimate that the cost of running the South Korean fossil gas fleet was 30 billion KRW_{2021}. Therefore, the cost savings of the transition to renewables represent over five times the annual running costs for fossil gas generation in the power sector[7].

This simple analysis underestimates the total cost savings of the transition from gas to renewables in multiple ways. First, it ignores any rise in international gas prices post-2021, taking fossil gas prices as of 2021 as a given. In reality, LNG prices spot prices in the Asian market grew 80% from 2021 to 2022 (S&P Global, 2023). While costs have fallen somewhat in recent months, resurgent gas demand growth in Asia could push prices back towards record highs (IEA, 2023). To the extent that LNG import prices remain above 2021 levels, this estimate of the cost savings will be an underestimate.

Secondly, the cost of importing fossil gas from abroad represents a value flow away from South Korea towards fossil fuel producing countries. On the other hand, some of the cost involved in installing renewable generation can remain in South Korea, as new jobs are created in installation, operation and maintenance of wind and solar farms (Climate Analytics and Solutions for Our Climate, 2021). Renewables deployment can also support South Korea's wind and solar manufacturing industries. A more detailed power system analysis could provide further information on the cost savings of the fossil gas phaseout, but this initial estimate suggests that there are clear economic benefits to the energy transition, rather than costs.

As well as displacing existing fossil generation, renewables will be required to meet future growth in electricity demand, as the transport, buildings and industry sectors are increasingly electrified. To assess the potential of renewables to meet future electricity demand, we explore an illustrative power sector transformation pathway for South Korea (Figure 13). The selected pathway is produced by the REMIND-MAgPIE integrated assessment modelling framework and is the REMIND-MAgPIE 2.1-4.2|EN_NPi2020_400 pathway.[8] This is one of the 21 pathways considered when determining a fossil gas emissions pathway for South Korea, which we analyse in more detail below.

[7] To calculate the cost savings of replacing gas with renewables, we compare the running cost of the gas plants (as given by the long-run marginal cost or LRMC), to the LCOE of renewable alternatives. Assuming that renewables are deployed based on their LCOE (with the lowest cost renewables deployed first), we can compare the running cost of the gas plants which are retired in a given year with the cost of the renewables which replace them. This allows us to estimate the cost savings of the switch from fossil gas to renewables.

[8] This pathway is produced as part of the ENGAGE model-intercomparison project. For more details see (Riahi et al., 2021).

The pathway is downscaled from the regional level to South Korea using the SIAMESE tool. For more details, see Appendix A2: Downscaling pathways from the regional to the national level. According to the illustrative pathway, South Korea's total electricity demand may reach around 1000 TWh_{el}/yr by 2030, further rising to 1750 TWh_{el}/yr in 2035. As seen in Table 3, Korea's renewable potentials are considerably greater than this future projected electricity demand. This suggests that a well-designed power grid with adequate storage could allow South Korea to meet its current and future electricity demand entirely from renewable sources.

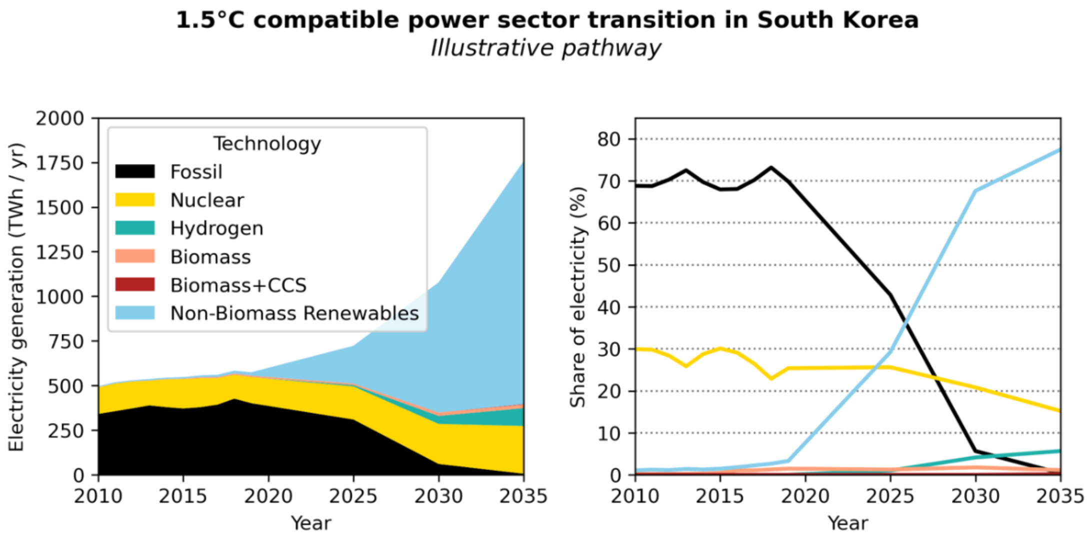

Figure 13: An illustrative power sector transition in South Korea.

Technical feasibility of highly renewable power systems

Our results highlight that there is ample renewable potential to displace fossil fuels and meet projected demand growth in South Korea, with potential strong cost savings from the transition. We do not directly perform detailed energy system modelling to analyse all of the power system dynamics involved in such a transition. However, numerous studies have explored the techno-economic feasibility of 100% renewable energy systems at global and regional levels (Brown et al., 2018; Jenkins et al., 2021; Ram et al., 2019; Victoria et al., 2020). These studies emphasise that highly renewable energy systems are not only feasible, but also economically viable and cost-effective.

Integrating high shares of VRES requires additional system flexibility to ensure the security of supply and to balance supply and demand at each point in time. Strategies to help integrate VRES include grid interconnection to smooth out variation in wind and solar generation across a broader area (Schlachtberger et al., 2017), demand-side flexibility (Söder et al., 2018), and energy storage (Zerrahn et al., 2018). On the supply side, utility-scale batteries and 'power-to-X' applications (e.g., power-to-hydrogen) can increase system flexibility by storing excess VRES generation, which can then be used in times of deficit.

Meanwhile on the demand side, direct and indirect electrification of end-use sectors (transport, buildings, and industry) offers new demand-side flexibility opportunities to the power system with increasing VRE shares.

We perform an initial assessment of the storage requirements needed to complement VRES deployment in the illustrative pathway (Figure 13). In this illustrative pathway, total electricity demand grows threefold from 2019 to 2035, while the share of renewables reaches around 80% by 2035. Peak demand in South Korea in 2019 was 90 GW. If peak demand grows at the same rate as total demand, then peak demand in 2035 would be around 270 GW. Taking data from a review of high-resolution electricity system modelling (Zerrahn et al., 2018), this would require around 90 GW of storage capacity to be deployed in South Korea by 2035.

This estimate of storage requirements is likely an overestimate, as the illustrative pathway it is based on overestimates of future demand growth in South Korea. This occurs because in the REMIND model, South Korea is aggregated into the "Rest of Asia" macro region. This region contains a range of less wealthy countries such as Bangladesh, Laos and Cambodia. These countries are likely to experience robust electricity demand growth and the region as a whole is projected to multiply its electricity demand over the next three decades by three-fold or higher (IEA, 2022b).

This strong demand growth then feeds through to the downscaled pathway for South Korea. However, in reality, demand growth in South Korea could be smaller. In the 10th Basic Electricity Plan, electricity demand in 2035 would be nearer 130 GW (Ministry of Trade Industry and Energy, 2023). This would reduce the supply-side challenges in scaling up renewables and storage capacity, making it easier to achieve a 2035 fossil gas phase-out.

We provide a rough estimate of the cost of pairing variable renewables with sufficient storage capacity, using values from the illustrative pathway (Figure 13)[9]. For this purpose, we assume that storage can be provided by Li-ion batteries with a storage duration of 3hr (in reality, a mix of storage options would likely be required, including long-duration storage. This is particularly the case if renewable penetration exceeds 80%). If the cost of this battery deployment is attributed solely to variable renewables, this would lead to a cost mark-up on their LCOEs of the order of 5 KRW_{2021}/kWh in the mid-2020s, which would then decline towards 1.5 KRW_{2021}/kWh by 2035, as battery costs decline (Kittner et al., 2020). This is a cost markup of less than 3% of the median cost of running the fossil gas fleet in South Korea. For more details see Appendix B4: Calculating storage cost markups. This storage mark-up is shown in Figure 14.

[9] The cost markup is calculated as a cost per kWh of VRES generation. To the extent that the illustrative pathway overestimates total electricity demand, it also overestimates VRES generation. These factors will compensate for one another in the overall cost mark-up calculation.

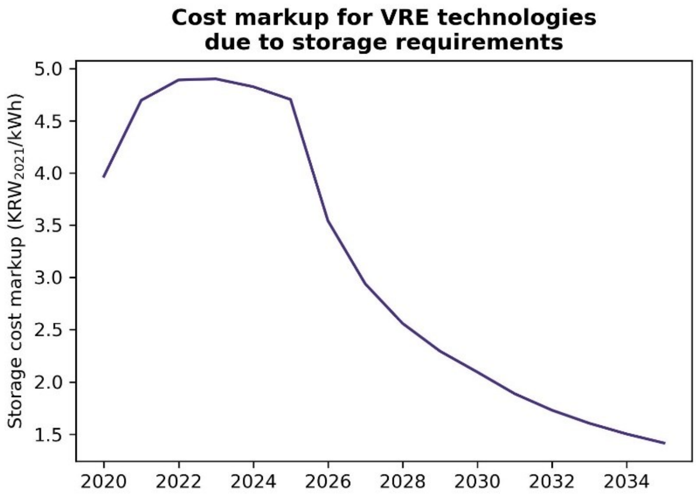

Figure 14: Storage cost mark-up to accompany VRES deployment with appropriate utility-scale storage.

This storage mark-up is not the result of detailed system modelling and should be seen as initial estimate of the storage requirements, rather than a detailed analysis. Power system dynamics would likely change substantially beyond renewable penetrations of 80%, requiring different levels and types of storage, with a much greater role for long-term electricity storage. This would require further analysis to explore.

Nevertheless, this simple analysis suggests that the additional cost of pairing VRES deployment with appropriate storage would be relatively low, and would not change the conclusions of this research, which demonstrates that there is a large renewable potential in South Korea that can provide zero-carbon electricity at costs lower than the existing fossil gas fleet.

Ensuring future heat supplies

Around a third of the gas-fired generation units currently operating in South Korea are CHP units, providing heat for the buildings and industry sector. These units provide around 47 TWh of heat in South Korea, which will need to be replaced alongside the electricity generation from these CHPs.

In our unit-level phase out analysis we consider this issue by distinguishing between CHP and combined cycle (CC) gas power units. We prioritise CC units for phaseout before the CHP units (all else being equal). This provides a longer time window to replace the heat supply from fossil-based CHP units with zero-carbon alternatives.

The most promising strategy to replace heat from gas CHPs is to accelerate the deployment of heat pumps. Deployment of heat pumps is accelerating across the globe (Rosenow et al., 2022), and they have been identified as a cornerstone of heat decarbonisation (IEA, 2021b).

As heat pumps can achieve above 100% efficiency, replacing 47 TWh of heat from CHPs via heat pumps would not require 47 TWh of additional electricity generation, but could be as little as 15 TWh_{el}. Heat pumps can also provide the low-temperature heat required for some areas of industrial electrification (Madeddu et al., 2020).

In some circumstances, an alternative option may be to convert existing fossil gas CHPs to run on renewable-based hydrogen instead. This would allow the continued utilisation of existing district heat networks, which could be valuable. However, it is important to highlight that this option should only be considered for *existing* fossil gas CHPs and is not a justification to build new fossil gas CHPs. In addition, the efficiency of producing green hydrogen via electrolysis for consumption in a hydrogen-based CHP is much lower than the efficiency of direct electrification via heat pumps (Weidner and Guillén-Gosálbez, 2023). As such, heat pumps retain a competitive advantage over green hydrogen in district heating, and the use of hydrogen-based CHPs should be limited to specific plants and locations.

Conclusions

A decarbonised power system is a key milestone on the road to net zero. Multiple studies taking multiple different perspectives have emphasised this point (Climate Analytics, 2022c; IEA, 2022c; Riahi et al., 2022). The power sector leads other sectors in reducing emissions to zero, and the next decade is particularly crucial for deployment of wind and solar and a rapid reduction in coal and fossil gas generation.

It is therefore valuable to develop country-specific roadmaps towards 100% clean electricity, taking into account the requirements of the 1.5°C temperature limit and the specific geographical and technical context of the country. This report has done so for South Korea, providing a detailed and actionable schedule that will lead to the phaseout of fossil gas in the country by 2034. Such a schedule can provide valuable information to national policymakers who are designing flagship climate and energy policies, and local decisionmakers who have responsibility for individual units and renewables permitting.

Key findings:

- To align with the 1.5°C limit, South Korea needs to reduce emissions in the power sector to 90% below 2022 levels by 2030 and reach zero emissions by 2034. Rapid and immediate power sector decarbonisation is crucial.

- To achieve this power sector decarbonisation, gas-fired power generation would need to fall by 60% over the 2022-2030 period, and fossil gas would need to be fully phased out of the power sector by 2034. The 1.5°C compatible phaseout starts in 2023, with gas-fired generation falling year on year across the horizon.

- There is no scope for building new gas-fired units post-2023, and all coal-to-gas conversion projects are incompatible with this phaseout schedule. The 101 units online as of the end of 2023 need to be retired by 2034 at the latest.

Roadmap to clean power

The report develops two phaseout schedules for these fossil gas units, which represent two distinct perspectives on how to prioritise gas plants for phaseout, to either maximise the economic or health-related benefits of the transition. These phaseout schedules account for a wide range of different indicators to provide a multi-criteria perspective on which units should be phased out first to align with this 1.5°C compatible pathway. On average 10 units need to be retired annually.

However, this average masks the front-loaded nature of the phaseout. In 2023 and 2024 together, these schedules require that 43-48 units are retired. These are generally smaller, older, less efficient, more expensive and more polluting units.

In particular, there is a set of 18 units which are prioritised for immediate phase out under both perspectives. These represent least-regret options which can be a focus for policymakers.

Finally, the report considers how South Korea could achieve this transition by exploiting its domestic renewable potential. There is ample renewable potential in South Korea to replace fossil fuels and meet future electricity demand. In addition, these renewables are much cheaper than the existing fossil gas fleet, meaning that a rapid transition to renewables will unlock cost savings compared to continued reliance on expensive and import-dependent gas-fired generation.

Implications for policymakers in South Korea

It is clear that the ambition contained in the 10th Basic Electricity Plan is not compatible with South Korea's commitments under the Paris Agreement. While the plan sees the share of coal and gas declining, in 2035 over a quarter of all electricity generation would still come from fossil fuels, and at this pace, South Korea would only achieve 100% clean electricity by around 2050. Figure 15 shows the deficiency of ambition in the 10th Basic Electricity Plan compared to the 1.5°C compatible transition assessed in this report, for both coal and gas. South Korea therefore has a crucial opportunity to amend the 10th Basic Electricity Plan, accelerate the fossil phaseout, and reap the cost savings and health benefits that have been identified in this report.

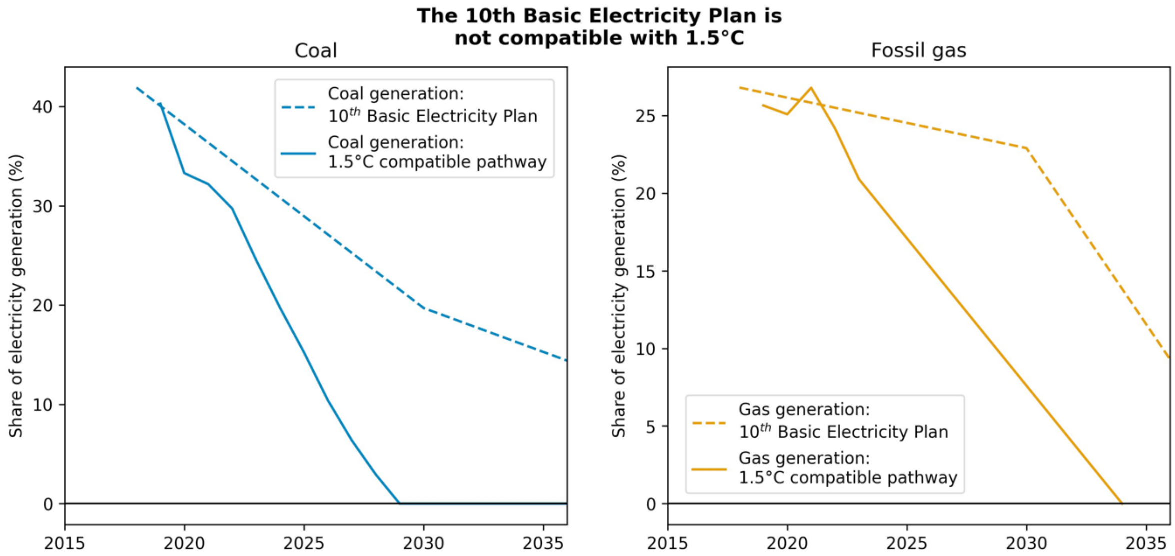

Figure 15: Comparing projected electricity demand in the 10th BEPSD to 1.5°C compatible transitions as assessed in this report.

Specific decisions on individual gas-fired power units need to be made now. Setting clear retirement dates for individual units can help plan a cost-effective and just transition, as worker retraining plans can be drawn up, replacement generation from renewables identified and permitted, and any supporting infrastructure installed.

Without such a unit-by-unit roadmap for a fossil gas phaseout, South Korea risks either a disorderly and costly transition or exceeding the 1.5°C compatible emissions budget for the power sector, or both. The results contained in this report provide valuable evidence to policymakers seeking to develop such a phaseout schedule.

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Appendix A: Determining a phaseout schedule for the fossil gas fleet

A1: Selecting pathways

Figure A1 highlights the key steps taken to select the final 21 pathways for analysis in this report.

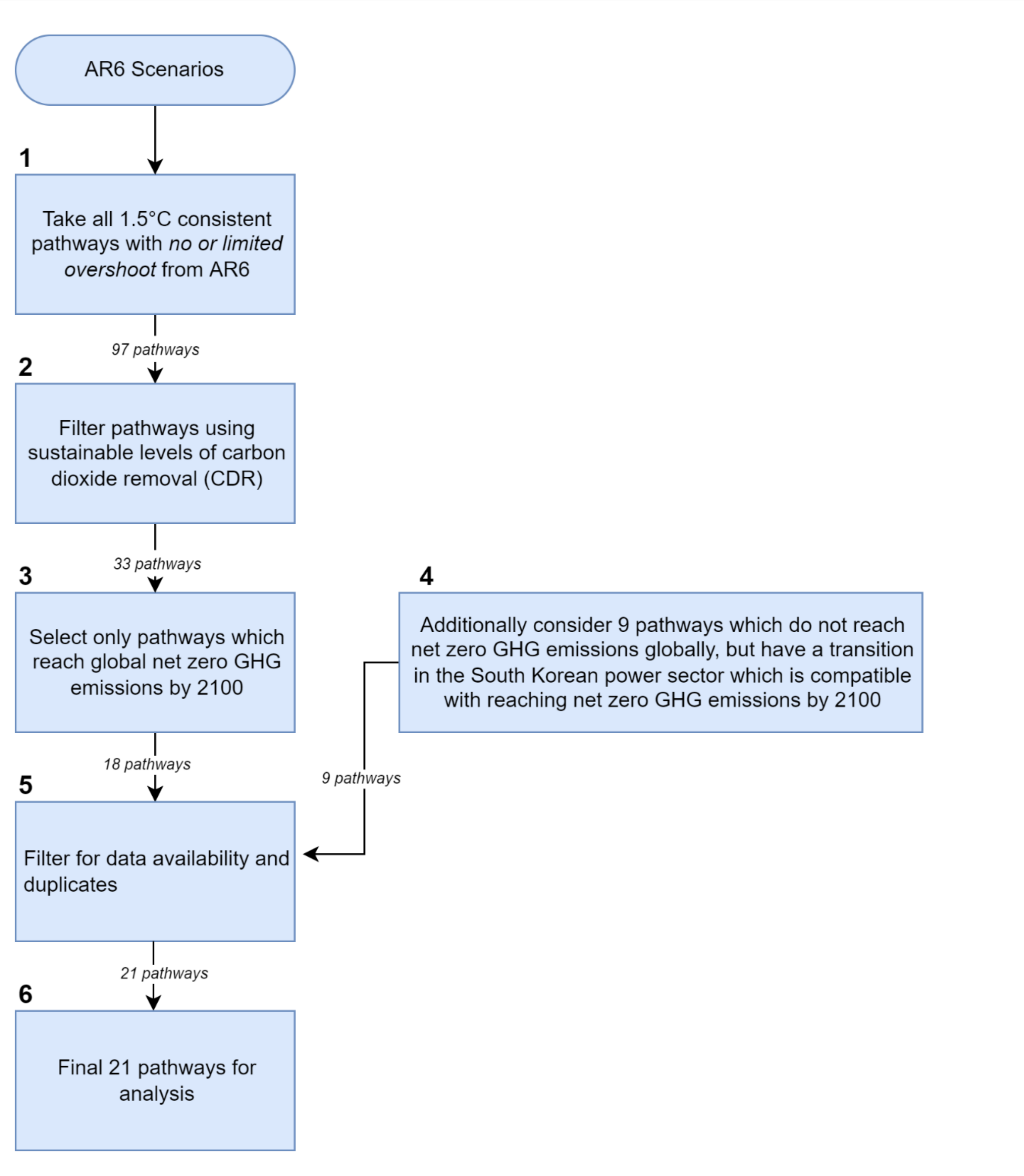

Figure A1: Flow-chart for selecting final pathways for analysis.

The four key criterion used for pathway selection are as follows:

1. 1.5°C compatibility

This analysis focuses on pathways which limit warming to 1.5°C with no or low overshoot. This means that they:

- Exceed warming of 1.5°C during the 21st century with a likelihood of 67% or less
- Limit warming to 1.5°C in 2100 with a likelihood of greater than 50%

Such pathways have no or low (<0.1°C) overshoot of the 1.5°C temperature limit, with warming returned to ~1.3°C by 2100.

These pathways are given the **C1 category** in the AR6 database. C1 pathways are compatible with the long-term temperature goal of the Paris Agreement set out in Article 2.1, which commits signatories to hold warming to "well below" 2°C and pursue efforts to limit warming to 1.5°C. There are 97 such pathways in the AR6 database.

2. Sustainable levels of CDR

Many pathways produced by IAMs rely on levels of carbon dioxide removal (CDR), which could be incompatible with broader sustainability concerns.

Therefore, we further filter the ensemble of pathways to only consider those limiting CDR deployment to sustainable levels (Fuss et al., 2018). This means that globally:

- They deploy less than 5 $GtCO_2$/yr of bioenergy with carbon capture and storage (BECCS) in 2050
- They deploy less than 3.6 $GtCO_2$/yr of afforestation and reforestation in the second half of the century.

This provides a set of 33 pathways for analysis.

3. Compatibility with Article 4.1 of the Paris Agreement

In order to achieve the long-term temperature goal, set out in Article 2 of the Paris Agreement, Article 4.1 sets out an aim to achieve global net-zero GHG emissions[10] in the second half of the century in accordance with the best available science.

The IPCC AR6 Working Group III made net zero GHGs in the second half of the century an explicit criterion for assessment and established a **subcategory C1a.** All C1a pathways achieve net zero greenhouse gas emissions around 2070-2075. These pathways also reach net zero CO_2 emissions around 2050.

We filter the pathways to only select power sector transitions which are compatible with reaching net-zero GHG emissions at the global level. We do this by selecting only pathways which are either subcategory C1a, or display faster emissions reductions in

[10] Defined as a balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases.

the South Korean power sector than the C1a pathways (Figure A1). This provides a set of 27 pathways for analysis.

4. Data availability

This set of 27 pathways is further filtered based on data availability. To facilitate downscaling to the national level, data must be available at the level of the ten major world regions or R10 level. This gives a set of 23 pathways. Of these, two were identified as duplicates, giving a final set of 21 pathways which form the basis of the analysis.

Table A1 lists the final pathways that are used in this analysis.

Table A1: Final 1.5°C compatible pathways selected for use in this analysis.

Model	Scenario
AIM/CGE 2.2	EN_NPi2020_300f
IMAGE 3.2	SSP2_SPA1_19I_LIRE_LB
REMIND 2.1	LeastTotalCost_LTC_brkLR15_SSP1_P50
REMIND 2.1	R2p1_SSP1-PkBudg900
REMIND-MAgPIE 2.1-4.2	CEMICS_SSP1-1p5C-fullCDR
REMIND-MAgPIE 2.1-4.2	CEMICS_SSP1-1p5C-minCDR
REMIND-MAgPIE 2.1-4.2	CEMICS_SSP2-1p5C-minCDR
REMIND-MAgPIE 2.1-4.2	EN_NPi2020_200f
REMIND-MAgPIE 2.1-4.2	EN_NPi2020_300f
REMIND-MAgPIE 2.1-4.2	EN_NPi2020_400
REMIND-MAgPIE 2.1-4.2	EN_NPi2020_400f
REMIND-MAgPIE 2.1-4.2	EN_NPi2020_500
REMIND-MAgPIE 2.1-4.2	EN_NPi2020_600
REMIND-MAgPIE 2.1-4.2	SusDev_SDP-PkBudg1000
REMIND-MAgPIE 2.1-4.2	SusDev_SSP1-PkBudg900
REMIND-MAgPIE 2.1-4.3	DeepElec_SSP2_ HighRE_Budg900
WITCH 5.0	EN_NPi2020_400f
WITCH 5.0	EN_NPi2020_450
WITCH 5.0	EN_NPi2020_450f
WITCH 5.0	EN_NPi2020_500
WITCH 5.0	EN_NPi2020_500f

A2: Downscaling pathways from the regional to the national level

Two downscaling approaches are used to obtain national mitigation pathways from these 1.5°C compatible pathways. The first, algorithmic approach, is used to downscale emissions in the power sector from the R10 level to the national level. This approach is described in more detail in the main body of the report (see section Selecting and downscaling pathways for analysis).

We also use the Simplified Integrated Assessment Model with Energy System Emulator (SIAMESE) tool to downscale the electricity mix to the national level. This method follows the following steps:

1. Historical electricity generation mix in the South Korean power sector are identified for a base year (2019).
2. The projected electricity generation mixes for the macro region containing South Korea are identified from the IAM pathway.
3. The generation mix of the macro region is downscaled to the national level. This is done by finding a fuel price equilibrium for the macro region, equating marginal fuel prices across all countries in the macro region. This gives a cost-effective electricity generation allocation, mimicking the internal logic of integrated assessment models.

A detailed description of the downscaling method can be found on the [1.5°C National Pathways Explorer website]() and in the literature (Sferra et al., 2019).

A3: Model-weighted quantiles

The 21 final pathways selected are produced by four different IAMs. Each IAM represents a particular perspective on how to model the energy transition, with associated differences in underlying assumptions and key dynamics. Therefore, if one model has a greater number of pathways represented in the final ensemble, this can result in one particular set of model dynamics being overrepresented in the final results.

We use model-weighted percentiles when defining the 1.5°C compatible emissions envelope, to prevent one model biasing the results unduly.

The approach uses two steps:

1. Each pathway is weighted according to the number of pathways that are produced by the same model in the overall ensemble. If a model provides n_{model} pathways, then each pathway received a weight of $1/n_{model}$. This ensures that overall, each model receives an equal overall weighting when calculating statistics from the distribution. As the REMIND integrated modelling assessment produced the majority of the pathways, this approach prevents these scenarios biasing the results unduly.

2. Having given weights to each pathway, percentiles from the distribution can then be calculated.

Figure A2 shows the impact of applying model-weighted quantiles to the distribution. The left panel shows the power sector emissions of all 21 selected pathways over time. While different pathways provide a variety of possible future emissions, all pathways achieve a highly decarbonised power sector by mid-century at the latest. Many scenarios go beyond this, achieving zero emissions in the power sector during the 2030s and, in some cases, achieving substantial net-negative CO_2 emissions by 2050.

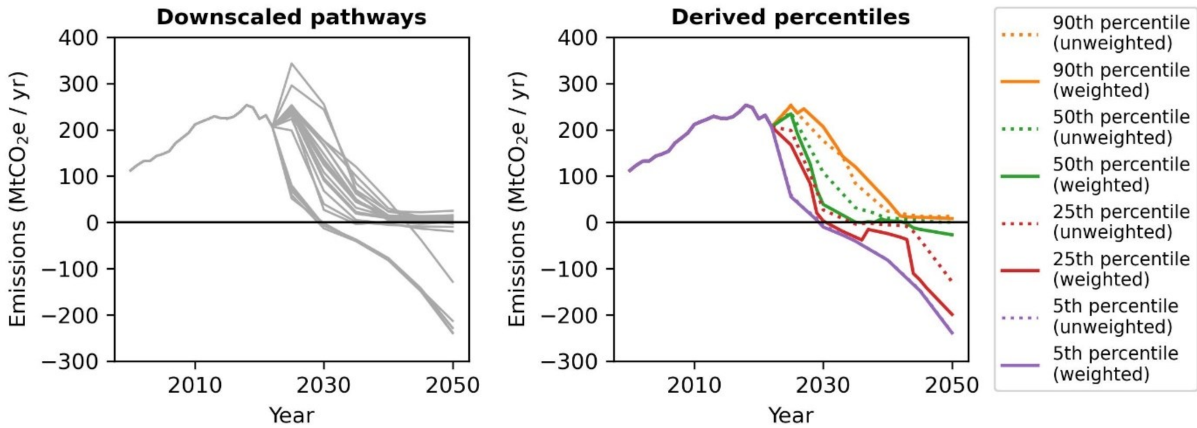

Figure A2: Calculating model-weighted percentiles from the distribution.

The right-hand panel shows how unweighted quantiles (where all pathways are weighted equally, allowing one model to potentially dominate the results), and model-weighted quantiles (where the total contribution of each model is weighted equally) differ. We can see that correcting for the model-related bias in the sample generally leads to lower emissions in the power sector.

This is because downscaled pathways derived from REMIND scenarios (which make up two thirds of the pathways assessed) tend to have higher overall power sector emissions for South Korea. When these scenarios are down-weighted to correct for this over-representation and consider the contributions from each modelling framework equivalently, the resultant emissions percentiles are reduced accordingly. This demonstrates the value of using model-weighted percentiles to correct for any model-related bias in the initial ensemble of pathways.

Appendix B: Unit-level multi-criteria analysis

B1: Calculation of indicators

The following section describes how the individual indicators are calculated for the multi-criteria analysis.

Efficiency

The efficiency of each gas-fired unit is taken directly from data provided by SFOC, which obtained it from the National Assembly. We take the average electricity efficiency over the 2019-2021 period to represent each unit's efficiency at converting fossil gas into electricity.

For units which come online in 2021-2023, there is no existing efficiency data available. For these units, we estimate the electrical efficiency based on the relationship between start year and efficiency in South Korea. Over time, South Korea's fossil gas fleet has grown in efficiency, with newer units generally having higher efficiencies. We perform a linear regression to estimate the efficiency of units which come online from 2021 onwards, distinguishing between CC and CHP units. The relationship between unit age and efficiency is shown in Figure B1. We also use this relationship to infill data for units where efficiency values were not reported in the raw data.

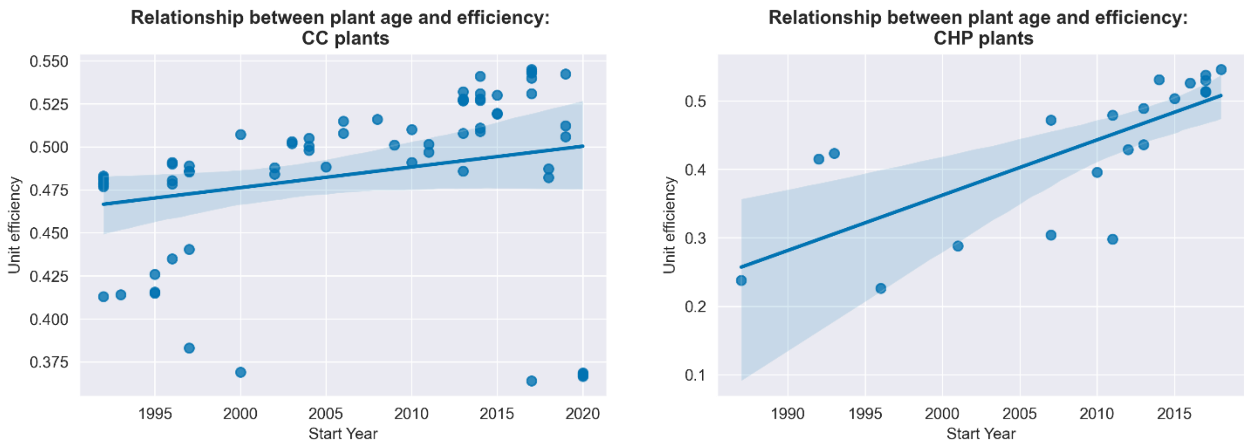

Figure B1: Relationship between unit age and efficiency.

Running cost

We use the long-run marginal cost (LRMC) as the measure of the running cost of a given gas plant. The LRMC is calculated by:

$$LRMC = Fuel\ Cost + VAROM + FIXOM + Carbon\ Cost$$

Fuel costs are calculated by combining data on average fuel costs by unit in 2021 (provided by SFOC, accessed from the National Assembly), with the efficiency of each unit (provided by SFOC or calculated as described above). For units which come online post-2021, we assume that the price paid per unit of fossil gas is the median of the 2021 gas price paid by the South Korean gas fleet.

Varying (VAROM) and fixed (FIXOM) maintenance costs for the fossil gas fleet are taken from the literature (Leigh Fisher, 2016), distinguishing between CC and CHP plants.

Carbon costs are taken by assuming the 2021 carbon price in South Korea of 26 $KRW_{2021}/kgCO_2$ (ICAP, 2021).

Air pollution

Fossil gas generation contributes significantly to air pollution via the formation of NO_x upon combustion, particularly nitrogen dioxide. This can lead to a range of negative health outcomes, including increased prevalence of asthma, premature births, other respiratory diseases, and premature death.

We consider the health impacts of each individual gas-fired unit, which we measure in health risks per GWh of generation. The data for this is taken from existing analysis by SFOC and the Centre for Research on Energy and Clean Air (CREA) (SFOC, 2021). This research performed a detailed analysis of the pollutants produced by each individual gas unit, their dispersion over population centres via atmospheric transport, the pollution levels in different locations and population exposure, and the resulting increasing in health risks. For more details, see SFOC (2021).

Start year

The start year of operation for each unit is taken directly from data provided by SFOC.

B2: Method of the multi-criteria decision analysis

For the multi-criteria decision analysis, all indicators/criteria are assigned into categories, see Figure B2:

- For the efficiency and start year indicator: values are sorted in ascending order and are then assigned into five categories of equal size. The lower the category (and hence the lower the efficiency/older the plant), the earlier this unit will be phased out.
- For the air pollution and running cost indicator: values are sorted in descending order and are then assigned into five categories of equal size. The lower the category, the earlier this unit will be phased out.
- For the technology indicator: if a unit is a combined cycle power plant, it is put into the category "1" and if a unit is a combined heat and power plant, it is put into the category "2". The lower the category, the earlier this unit will be phased out – representing a preference to phase out CC plants before CHP plants, all else being equal.

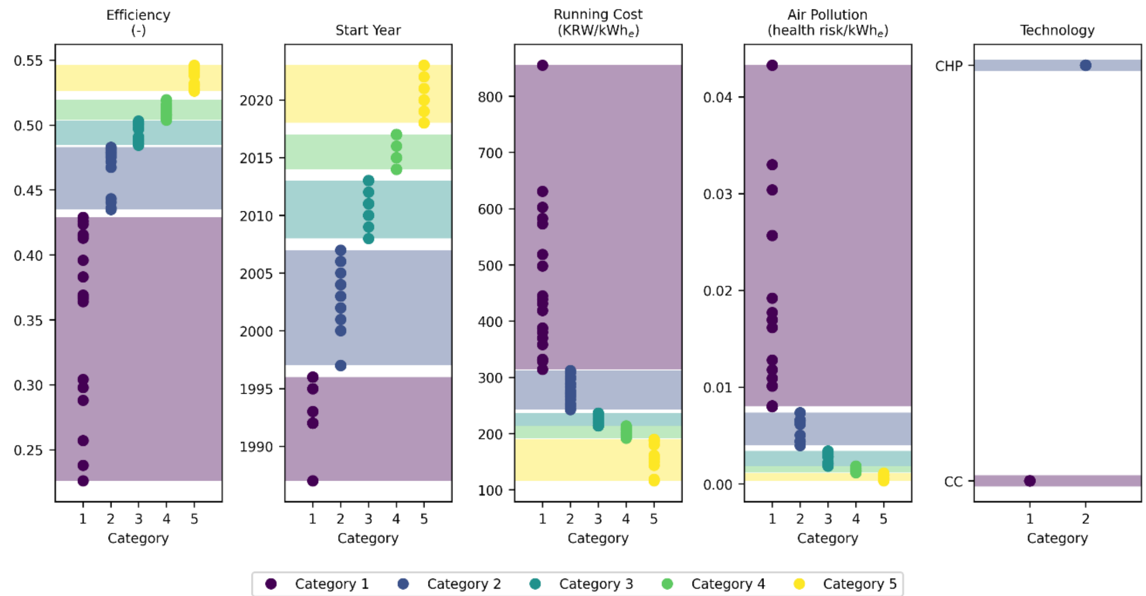

Figure B2: Categorisation of indicators.

The data is then converted into a table where the rows represent the units and the columns represent the indicators/criteria. The columns are sorted based on the order of preference, given by the perspective of the specific phaseout schedule being produced. The criterion found most relevant comes first, the one found least relevant last. The rows are then sorted in ascending order, one column after the other. For an illustrative example of this approach, compare the unsorted Table B1 and the sorted Table B2. The resultant tables for each case study are shown in Figure B3 and Figure B4.

Table B1: Illustrative example of an unsorted indicator table.

	Criterion 1 (less relevant)	Criterion 2 (more relevant)
Unit 1	2	1
Unit 2	1	2
Unit 3	1	1

Table B2: Illustrative example of a sorted indicator table.

	Criterion 2 (more relevant)	Criterion 1 (less relevant)
Unit 3	1	1
Unit 1	1	2
Unit 2	2	1

B3: Additional outputs of the multi-criteria decision analysis

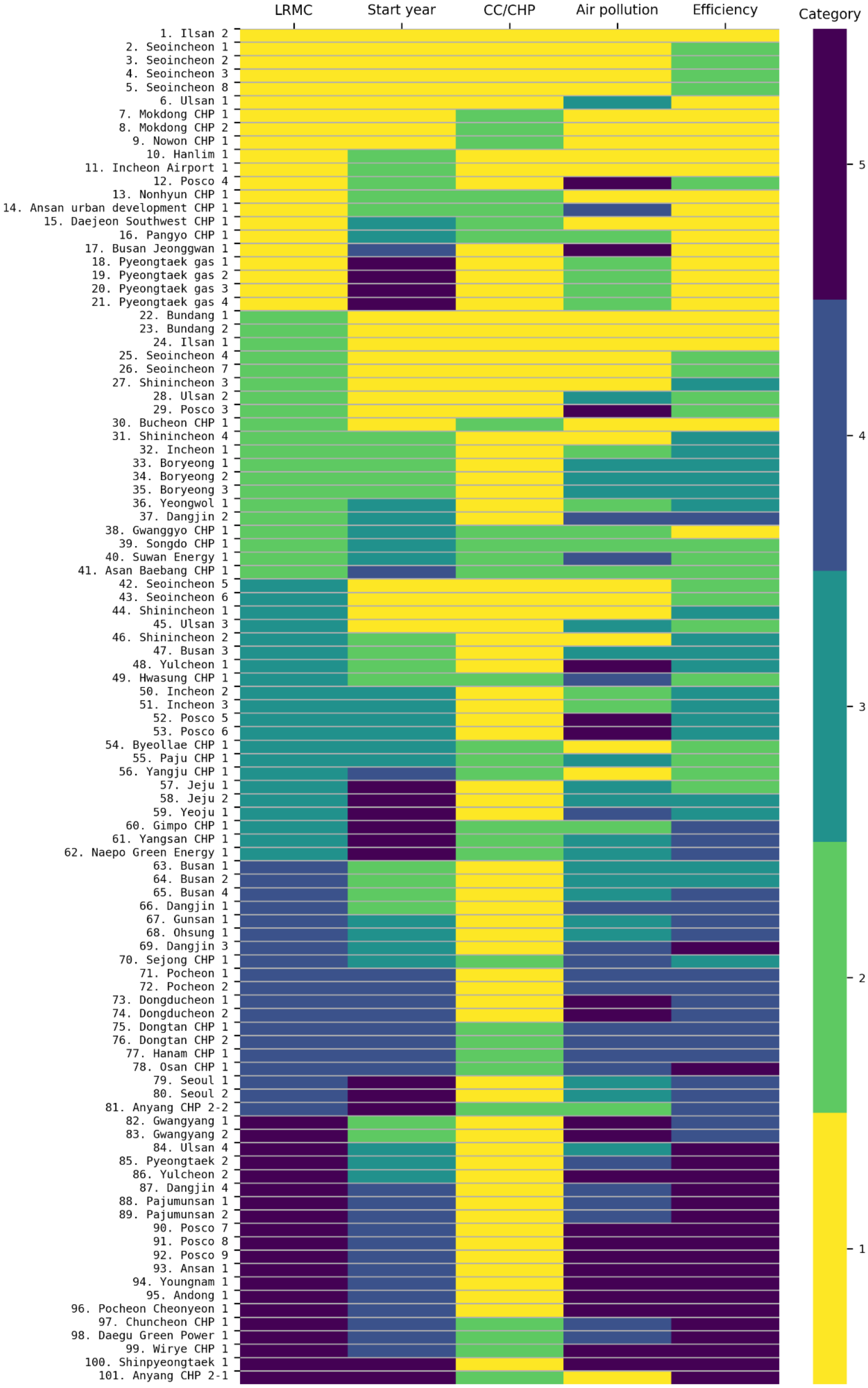

Figure B3: Sorted unit level phaseout schedule based on the 'cost focus' perspective.

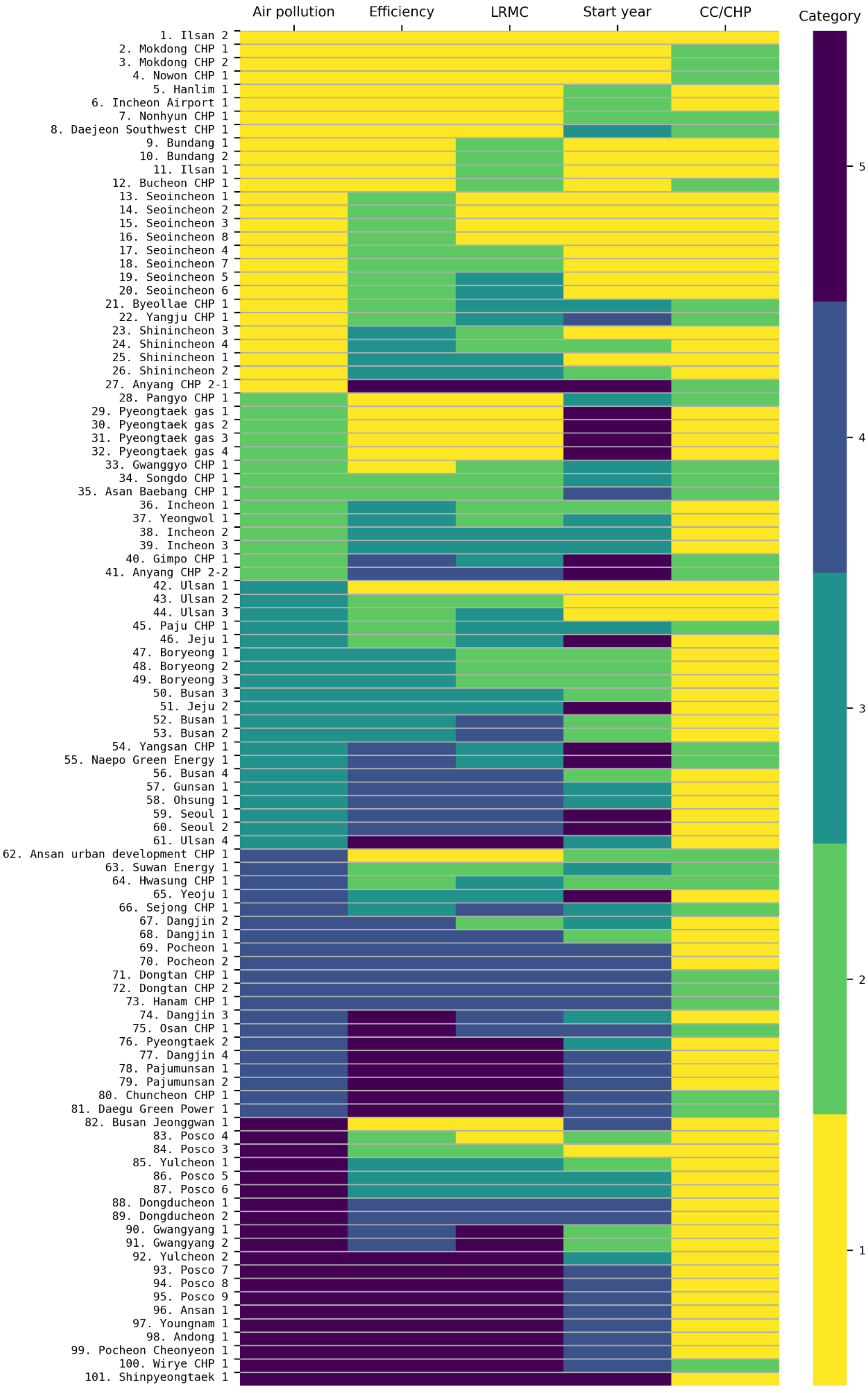

Figure B4: Sorted unit level phaseout schedule based on the 'health focus' perspective.

B4: Calculating storage cost markups

In this report, we provide an initial estimate of the storage cost mark-up that would be applied to wind and solar generation, if all VRES generation is accompanied by appropriate storage deployment.

To produce this calculation, we combine a range of data points from different sources. First, from the illustrative pathway (Figure 13) we take total demand growth from 2019-2035 and the share of variable renewables in the power sector. Total electricity demand grows threefold from 2019-2035 in this pathway, and the share of variable renewables reaches 80% by 2035.

We then use data from the literature (Zerrahn et al., 2018), which describes storage requirements as a share of peak electricity demand for different penetrations of VRES generation. At 80% VRES penetration, storage capacity equivalent to 34% of peak electricity demand is required. This means that in 2035, around 90 GW of storage capacity would be required.

We then calculate the investment costs of deploying 90 GW of storage by 2035, using recent cost estimates for Li-ion batteries from the literature (Kittner et al., 2020). This cost is annuitized, and the annual investment cost is then shared across the VRES generation in each year, to give the cost mark-up in KRW per kWh of VRES generation for this storage deployment.

Appendix C: Nearby renewable energy resources

To assess the technical potential of VRES in South Korea, we developed a python-based simulation pipeline, applying the temporally and spatially-resolved simulation models of the open-source python packages GLAES[11] (Geospatial Land Eligibility for Energy Systems) and RESKit[12] (Renewable Energy Simulation Toolkit) (Ryberg, 2019).

At first, the land eligibility analysis, evaluates the amount and distribution of suitable area of land/ocean for installing wind turbines and PV modules. The land eligibility assessment considers a comprehensive set of exclusion factors and constraints informed by the literature review. These reflect the most common (socio-political, physical, conservation, pseudo-economic) constraints for placement of wind turbines and solar panels commonly considered in renewable potential studies. Table C1 provides an overview of exclusion factors applied in our analysis for different renewable technologies.

[11] Find more information on https://github.com/FZJ-IEK3-VSA/glaes
[12] Find more information on https://github.com/FZJ-IEK3-VSA/RESKit

Table C1: Exclusion factors and underlying assumptions in land eligibility analysis.

Technology	Aspect	Description	Exclusion buffer limits	Source
Wind onshore	Regional boundaries	500m buffer distance from regional boundaries excluded	≤ 500 m	(Heuser et al., 2019)
	Primary roads	500m buffer distance from primary roads excluded	≤ 500 m	(Heuser et al., 2019)
	Railways	500m buffer distance from railways excluded	≤ 500 m	(Heuser et al., 2019)
	Waterways (Rivers)	150m buffer distance from waterways excluded	≤ 150 m	(Heuser et al., 2019)
	Airports	5000m buffer distance from airports excluded	≤ 5000 m	(Heuser et al., 2019; Ryberg, 2019; Ryberg et al., 2020, 2019)
	Urban settlements	1000m buffer distance from urban settlements excluded	≤ 1000 m	(Heuser et al., 2019)
	Woodlands	Base assumption: 300m buffer distance from woodlands (tree cover, broadleaved, needle leaved, mixed leaf type) excluded	≤ 300 m	(Heuser et al., 2019)
	Woodlands	Sensitivity: 300m buffer distance from naturally regenerating forests	≤ 300 m	(Lesiv et al., 2022)
	Water bodies	1000m buffer distance from water bodies excluded	≤ 1000 m	(Heuser et al., 2019)
	Protected areas	1000m buffer distance from protected parks, monuments, reserves, and	≤ 1000 m	(Heuser et al., 2019)

		wildernesses excluded		
	Bird protected areas	1500m buffer distance from protected habitats and bird areas excluded	≤ 1500 m	(Heuser et al., 2019)
	Elevation	Terrain elevation above 1500 m excluded.	≥ 1500 m	(Heuser et al., 2019)
	Terrain Slope	Areas with a terrain slope angle above 17° excluded.	≥ 17°	(Ryberg, 2019; Ryberg et al., 2020, 2019)
Wind offshore	Water depth	Water depths greater than the maximum (200m) excluded	≥ 200 m	RE White paper translation
	Distance to shore	5000 m buffer distance from shore excluded.	≤ 5000 m	Own assumption based on regional aspects and ranges given in literature (Caglayan et al., 2019; Ryberg et al., 2018)
	Protected areas	3000 m buffer distance from protected areas excluded	≤ 3000 m	(Caglayan et al., 2019)
	Bird protected areas	5000 m buffer distance from bird protected areas excluded	≤ 5000 m	(Caglayan et al., 2019)
	Shipping routes	2600m buffer distance from shipping routes	<= 2600 m	Caglayan et al. 2019)
PV Open-field	Primary roads	50m buffer distance from primary roads included	≤ 50 m	own assumption
	Railways	50m buffer distance from railways included	≤ 50 m	own assumption
	Airports	0m buffer distance from airports excluded	≤ 0 m	own assumption based on (Ryberg, 2019)
	Urban settlements	500m buffer distance from urban area excluded	≤ 500 m	own assumption
	Woodlands	0m buffer distance from woodlands	≤ 0 m	own assumption

		(tree cover, broadleaved, needle leaved, mixed leaf type) excluded		
	Water bodies	0m buffer distance from water bodies excluded	≤ 0 m	own assumption
	Protected areas	0m buffer distance from protected parks, monuments, reserves, and wildernesses excluded	≤ 0 m	Own assumption
	Agricultural areas	0m buffer distance from agricultural land, (cropland (rainfed), cropland (rainfed with tree or shrub cover), cropland (irrigated), cropland (mosaic), natural vegetation (mosaic)) excluded	≤ 0 m	Own assumption based on (Ryberg, 2019)
	Elevation	Terrain elevation higher than 1750m excluded	≥ 1750 m	(Ryberg, 2019)
	Slope: Total	Areas with a terrain slope angle above 10° excluded.	≥ 10°	(Ryberg, 2019)
	Slope: Northward	Areas with a north-facing slope angle above 3° excluded.	≥ 3°	(Ryberg, 2019)
PV Rooftop	Population density	Only areas with a non-zero population density taken into account		(Ryberg, 2019)

The land eligibility analysis is performed step-wise, where different constraints and exclusion criteria, as indicated in Table C1, are applied one after the other. Figure C1 shows the final results from land eligibility analysis for different renewable technologies.

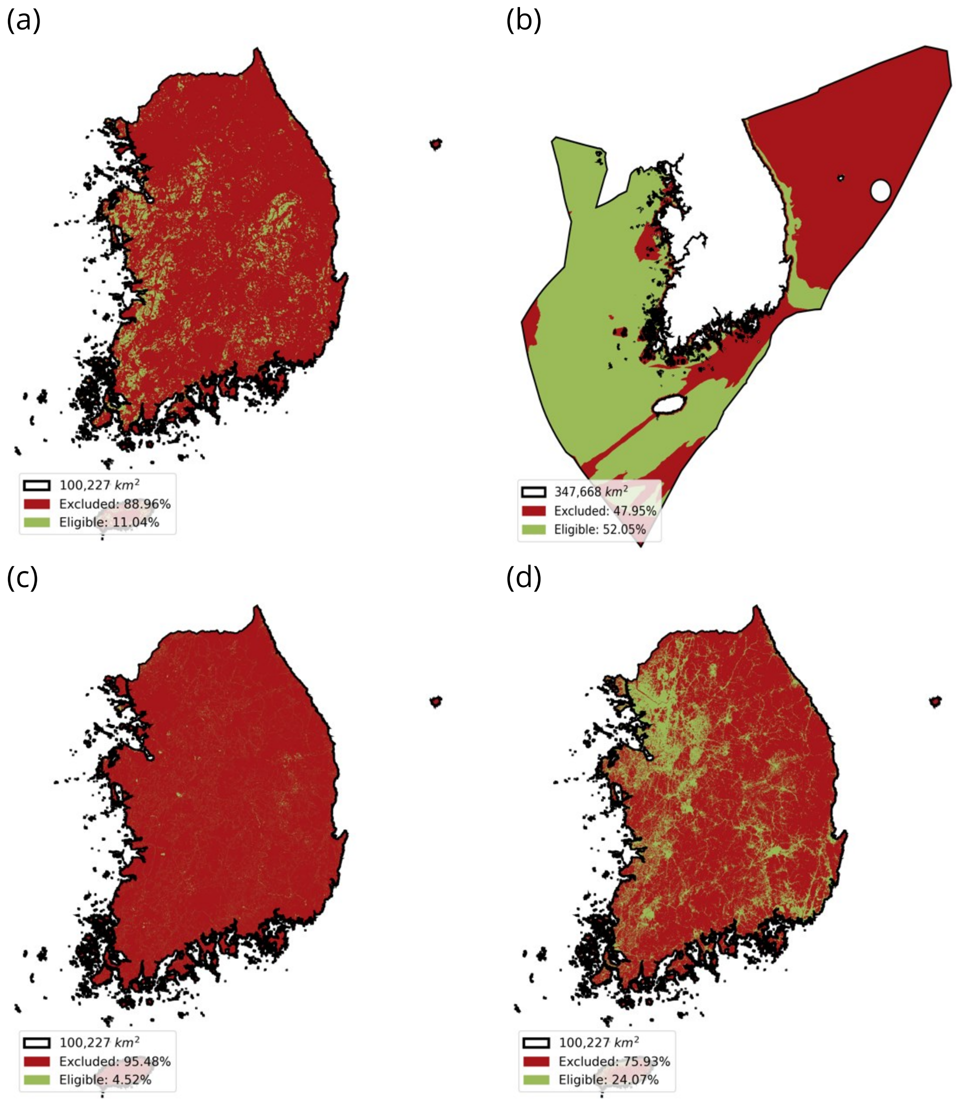

Figure C1: Land eligibility analysis results (a) Onshore wind (b) Offshore wind (c) Open-field PV (d) Rooftop PV

After the land eligibility analysis conducted by GLAES, the placement algorithm RESkit identifies locations of individual turbines/PV modules within the eligible areas. For wind turbines, the algorithm also includes an optimisation which varies the technical design parameters of turbine over a given range to derive the cost-optimal level of hub height and rotor diameter which leads to the minimum levelized cost of electricity (LCOE) for each location. This is followed by hourly simulation of generation profiles for each location, accounting for wind speed/solar irradiance data at the location.

As an output of this modelling step, installed capacity, generation profiles as well as LCOEs are determined for each location. The results are aggregated to a national context to get the country's maximum technical potential for different renewable energy sources.

Table C2 provides an overview of assumptions made in this work regarding the baseline turbine design for onshore and offshore applications. Table C3 gives an overview on range of assumptions made for different possible levels of turbine's technical design parameters in the optimisation algorithm embedded in our renewable potential analysis framework. Table C4 provides the characteristics of PV modules applied in this study for open-field and roof-top applications as well as the economic assumptions.

Table C2: Baseline turbine's technical design and economic parameters.

Technology	Aspect	Assumption and parameter choice	Source
Wind onshore	Hub height	101m	(BWE, 2021) and https://en.wind-turbine-models.com/turbines/1719-ge-general-electric-ge-4.8-158-cypress
	Rotor diameter	158m	(IRENA, 2019a)
	Capacity	4.8MW	(IRENA, 2019a)
	Specific power	245 W m^{-2}	(IRENA, 2019a)
	Capital Cost (2020)	1108 (Low) – 1473 (medium) 2019 USD/kW	(IRENA, 2020, 2019a)
	Capital Cost (2030)	800 (Low) – 1075 (medium) 2019 USD/kW	(IRENA, 2019a)
	Annual operating cost	2% capex	(IRENA, 2020)
	Economic lifetime	20 years	https://www.nrel.gov/analysis/tech-footprint.html
Wind offshore	Hub height	120m	(Onea and Rusu, 2018; Wang et al., 2020)
	Rotor diameter	164m	(IRENA, 2019a)
	Capacity	10MW	(IRENA, 2019a)
	Specific power	474 W m^{-2}	
	Foundation type	Monopile/ fixed	
	Capital Cost (2020)	2890 (Low) – 3800 (medium) 2019 USD/kW	(IRENA, 2020, 2019a)
	Capital Cost (2030)	1700 (Low) – 3200 (medium) 2019 USD/kW	(IRENA, 2019a)
	Annual operating cost	2% capex	(IRENA, 2020)
	Economic lifetime	20 years	https://www.nrel.gov/analysis/tech-footprint.html

Table C3: Range of assumptions and parameter choices made for turbine technical design parameters.

Technology	Aspect	Assumption and parameter choice	Source
Wind onshore	Hub height	80m, 99m	Own assumptions based on the typical ranges and the optimal value derived from sensitivity analysis
	Rotor diameter	80, 100, 117, 136	Same as above
	Capacity	0.8MW, 1 MW	Same as above
Wind offshore	Hub height	110m, 130m, 150m	Same as above
	Rotor diameter	141, 180, 200, 220	Same as above
	Capacity	5MW, 7MW, 9MW	Same as above
	Foundation type	Fixed foundation (<100 m depth), floating foundation (≥ 100m depth)	Own assumption

Table C4: Selected PV module characteristics for open-field and roof-top applications.

Technology	Aspect	Assumption and parameter choice	Source
PV open-field	Module name	Winaico WSx-240P6	(Ryberg, 2019)
	P_{mp}	240.4 W	(Ryberg, 2019)
	Area	1.663 m^2	(Ryberg, 2019)
	Efficiency	24%	(Ryberg, 2019)
	Technology	Polycrystalline	(Ryberg, 2019)
	Coverage	30 m^2_{land} kWp^{-1}	Own assumption based on the insights from (Ryberg, 2019)
	Type (fixed tilt/single axis tracking)	Fixed-tilt	
	Capital Cost (2020)	714 (Low) – 995 (medium) 2019 USD/kWp	(IRENA, 2020)
	Capital Cost (2030)	340 (Low) – 587 (medium) 2019 USD/kWp	(IRENA, 2019b)
	Operating Cost	1.7% capex	(Ryberg, 2019)
	Economic lifetime	25 years	(NREL, 2023)
PV Rooftop	Module name	LG 360Q1C-A5	(Ryberg, 2019)
	P_{mp}	379.4 W	(Ryberg, 2019)
	Area	1.673 m^2	(Ryberg, 2019)

	Efficiency	30%	(Ryberg, 2019)
	Technology	Mono-crystalline	(Ryberg, 2019)
	Coverage	9.1 m^2_{land} kWp^{-1}	Own assumption based on the insights from (Ryberg, 2019)
	Type (fixed tilt/single axis tracking	Fixed-tilt	
	Capital Cost[13] (2020)	821 (Low) – 1144 (medium) 2019 USD/kWp	(IRENA, 2020)
	Capital Cost (2030)	391 (Low) – 675 (medium) 2019 USD/kWp	(IRENA, 2019b)
	Operating Cost	1.7% capex	(IRENA, 2020)
	Economic lifetime	25 years	(NREL, 2023)

[13] Costs for PV rooftop are calculated based on the ratio between PV utility and rooftop costs given both for South Korea according to (IRENA, 2020)

In addition, the renewable potential assessment framework derives the distribution of levelized costs of electricity (LCOE) for different renewable energy sources. For instance, Figure C2 visualises the LCOE distribution over eligible areas for onshore wind, offshore wind, PV open-field and PV rooftop in South Korea.

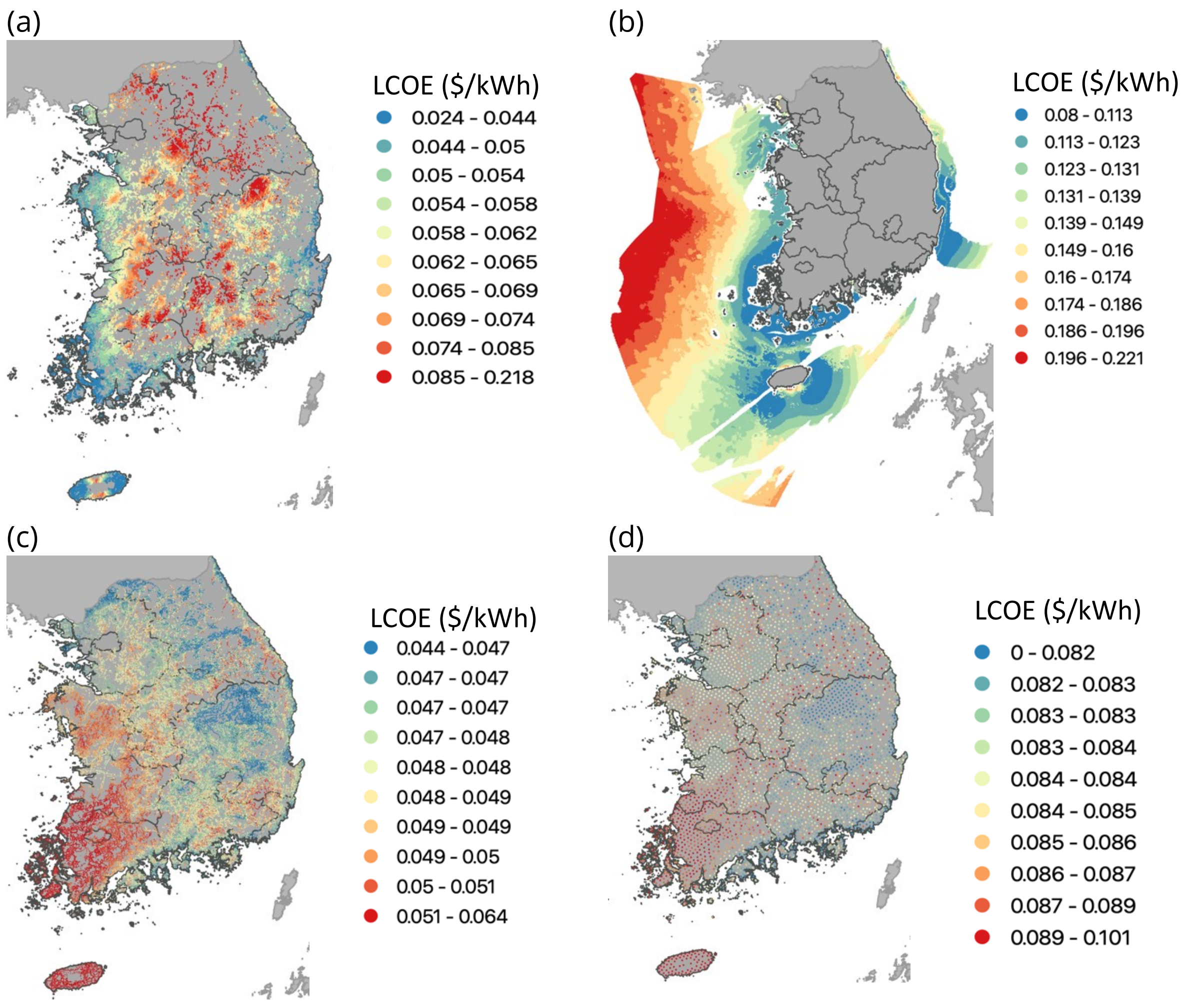

Figure C2: Technoeconomic potential of variable renewable energy sources in South Korea: spatial distribution of LCOE for (a) Onshore wind (b) Offshore wind (c) Open-field PV (d) Rooftop PV. Note: this is based on medium cost scenario assumptions for 2020 (see Table C2, Table C3, and Table C4 for economic parameters).

The sites with higher LCOE mainly correspond to those locations with lower full load hours and vice versa. Figure C3 visualises the distribution of full load hours over eligible areas for onshore wind, offshore wind, PV open-field and PV rooftop.

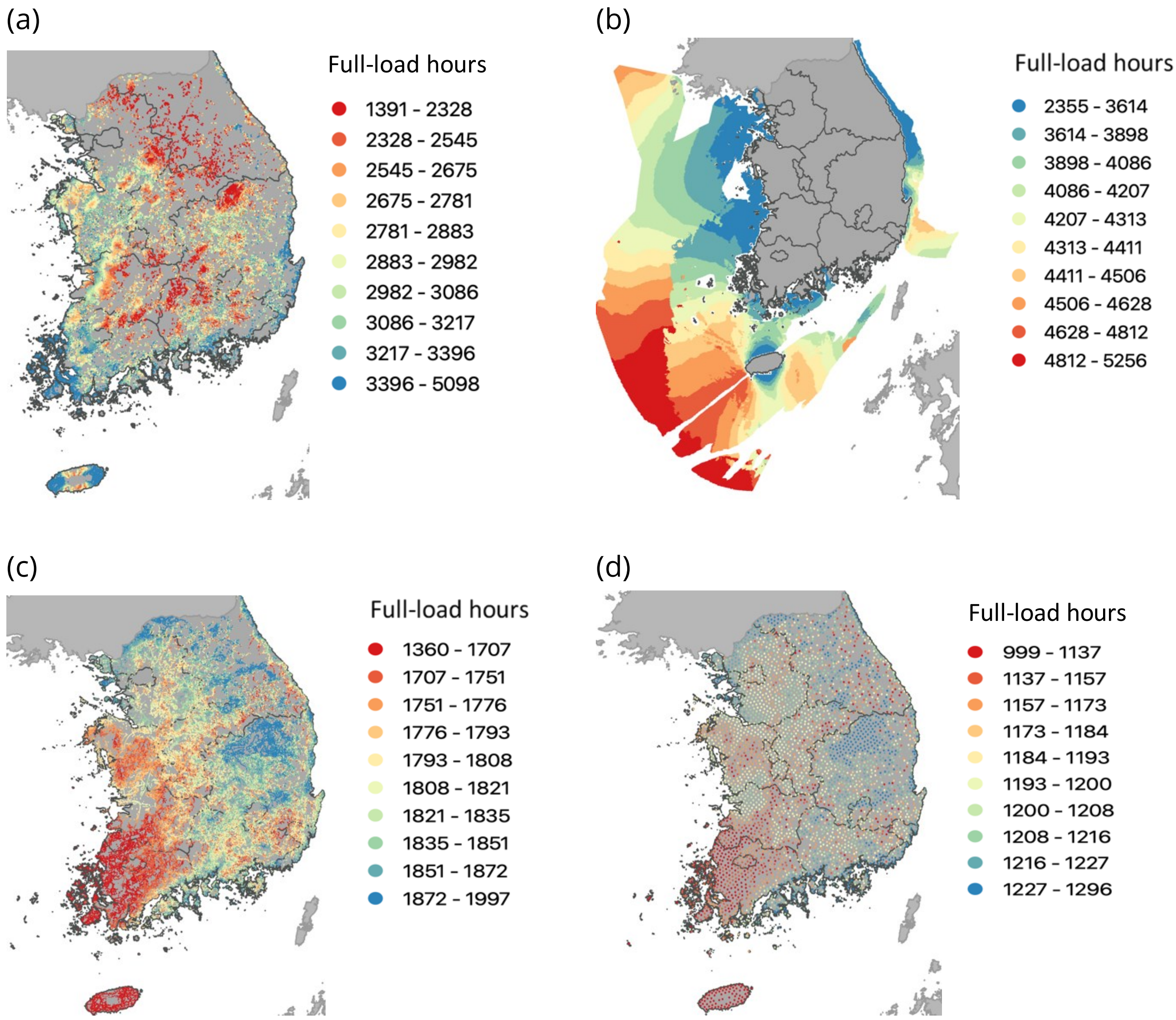

Figure C3: Technoeconomic potential of variable renewable energy sources in South Korea: Spatial distribution of full load hours for (a) Wind onshore (b) Wind offshore (c) Open-field PV (d) Rooftop PV.

Appendix D: Data

Table D1 provides key input data for each fossil gas unit in South Korea, in terms of its location, average generation across 2019-2020, and capacity.

Table D1: Initial data on individual units provided by SFOC or inferred by Climate Analytics.

Plant name	Unit	Longitude	Latitude	Average 2019-2020 Generation [MWh]	Capacity [MW]
Andong	1	128.5413	36.5959	1968	362
Ansan	1	126.4641	37.1740	4597	751
Ansan urban development CHP	1	126.7944	37.2956	162	60
Anyang CHP	2-1	126.9285	37.4055	1421	482
Anyang CHP	2-2	126.9669	37.3943	2664	468
Asan Baebang CHP	1	127.0940	36.8006	213	102
Boryeong	1	126.2908	36.2351	115	450
Boryeong	2	126.2908	36.2346	247	450
Boryeong	3	126.2908	36.2344	262	450
Bucheon CHP	1	126.7640	37.5225	676	450
Bundang	1	127.1464	37.3641	1152	574
Bundang	2	127.1480	36.3641	1098	348
Busan	1	129.0003	35.0851	1288	450
Busan	2	129.0003	35.0851	1699	450
Busan	3	129.0003	35.0851	1300	450
Busan	4	129.0003	35.0851	1908	450
Busan Jeonggwan	1	129.1784	35.3152	110	46
Byeollae CHP	1	127.1131	37.6543	365	115
Chuncheon CHP	1	127.4625	37.4554	2699	431
Daegu Green Power	1	128.6122	35.8747	2562	371
Daejeon Southwest CHP	1	126.6404	37.5689	98	48
Dangjin	1	126.7825	36.9590	1346	501
Dangjin	2	126.7825	36.9590	144	533
Dangjin	3	126.7825	36.9590	502	382
Dangjin	4	126.7825	36.9590	5003	846
Dongducheon	1	127.0900	37.9030	3069	858
Dongducheon	2	127.0900	37.9030	2485	858
Dongtan CHP	1	127.0927	37.1755	2116	378
Dongtan CHP	2	127.0938	37.1754	2229	378
Gimpo CHP	1	126.5891	37.6020	2969	495
Gunsan	1	126.7313	35.9836	1844	718
Gwanggyo CHP	1	127.0610	37.2978	733	145
Gwangyang	1	127.7747	34.8895	3848	495
Gwangyang	2	127.7747	34.8895	3860	495
Hanam CHP	1	127.2150	37.5488	1602	364

Hanlim	1	126.2721	33.4023	404	105
Hwasung CHP	1	127.0778	37.2155	2509	512
Ilsan	1	126.4749	37.3851	834	600
Ilsan	2	126.4747	37.3854	357	300
Incheon	1	126.6095	37.5104	268	504
Incheon	2	126.6106	37.5099	821	509
Incheon	3	126.6083	37.5100	1907	450
Incheon Airport	1	126.4785	37.4928	322	127
Jeju	1	126.5900	33.5300	385	114
Jeju	2	126.5900	33.5300	416	114
Mokdong CHP	1	126.8848	37.5406	22	21
Mokdong CHP	2	126.8855	37.5399	1	3
Naepo Green Energy	1	126.6879	36.6605	2969	495
Nonhyun CHP	1	126.7145	37.3965	12	24
Nowon CHP	1	127.0583	37.6410	112	37
Ohsung	1	127.0027	37.0254	3542	770
Osan CHP	1	127.0796	37.1471	3375	436
Paju CHP	1	126.6404	37.5689	2199	516
Pajumunsan	1	126.7586	37.7615	5960	848
Pajumunsan	2	126.7586	37.7615	6175	848
Pangyo CHP	1	127.1029	37.3944	839	146
Pocheon	1	127.1689	37.9465	1681	725
Pocheon	2	127.1689	37.9465	1250	725
Pocheon Cheonyeon	1	127.1926	37.8972	3813	874
Posco	3	126.6125	37.5086	2998	450
Posco	4	126.6125	37.5086	839	450
Posco	5	126.6125	37.5086	839	575
Posco	6	126.6125	37.5086	891	575
Posco	7	126.6125	37.5086	2835	376
Posco	8	126.6125	37.5086	2326	376
Posco	9	126.6125	37.5086	2542	376
Pyeongtaek	2	126.7980	37.0067	4008	869
Pyeongtaek gas	1	126.7950	37.0030	116	350
Pyeongtaek gas	2	126.7950	37.0030	137	350
Pyeongtaek gas	3	126.7940	37.0040	204	350
Pyeongtaek gas	4	126.7940	37.0040	133	350
Sejong CHP	1	127.2481	36.4679	2896	530
Seoincheon	1	126.6005	37.5359	81	225
Seoincheon	2	126.6007	37.5358	42	225
Seoincheon	3	126.6015	37.5357	82	225
Seoincheon	4	126.6022	37.5358	113	225
Seoincheon	5	126.6031	37.5355	984	225
Seoincheon	6	126.6037	37.5357	819	225
Seoincheon	7	126.6046	37.5356	154	225
Seoincheon	8	126.6050	37.5356	40	225
Seoul	1	126.9166	37.5444	1398	369
Seoul	2	126.9166	37.5444	1487	369

Shinincheon	1	126.6159	37.5080	1923	450
Shinincheon	2	126.6159	37.5080	396	450
Shinincheon	3	126.6159	37.5080	388	450
Shinincheon	4	126.6159	37.5080	243	450
Shinpyeongtaek	1	126.7982	37.0075	3853	863
Songdo CHP	1	126.6402	37.3699	795	187
Suwan Energy	1	126.8298	35.1971	357	115
Ulsan	1	129.2258	35.2838	312	300
Ulsan	2	129.2249	35.2825	595	450
Ulsan	3	129.2246	35.2821	990	450
Ulsan	4	129.2257	35.2903	4483	872
Wirye CHP	1	127.1440	37.4829	3185	413
Yangju CHP	1	127.1003	37.8353	871	524
Yangsan CHP	1	129.0335	35.3632	713	119
Yeoju	1	127.6584	37.3618	4373	1004
Yeongwol	1	128.4923	37.1629	410	848
Youngnam	1	129.3841	35.5139	2945	443
Yulcheon	1	127.5930	34.9130	1842	526
Yulcheon	2	127.5930	34.9130	4845	864

Table D2 shows the phaseout years for each individual unit in South Korea, across the two different phaseout schedules produced in this report.

Table D2: Phaseout years for individual gas-fired units.

Plant name	Unit	Phaseout year: cost focus	Phaseout year: health focus
Andong	1	2032	2033
Ansan	1	2032	2032
Ansan urban development CHP	1	2023	2026
Anyang CHP	2-1	2033	2024
Anyang CHP	2-2	2029	2024
Asan Baebang CHP	1	2024	2024
Boryeong	1	2024	2025
Boryeong	2	2024	2025
Boryeong	3	2024	2025
Bucheon CHP	1	2024	2023
Bundang	1	2023	2023
Bundang	2	2023	2023
Busan	1	2026	2025
Busan	2	2026	2025
Busan	3	2024	2025
Busan	4	2026	2026
Busan Jeonggwan	1	2023	2030
Byeollae CHP	1	2025	2023
Chuncheon CHP	1	2033	2030
Daegu Green Power	1	2033	2030

Daejeon Southwest CHP	1	2023	2023
Dangjin	1	2026	2027
Dangjin	2	2024	2027
Dangjin	3	2027	2028
Dangjin	4	2030	2029
Dongducheon	1	2027	2031
Dongducheon	2	2028	2031
Dongtan CHP	1	2028	2028
Dongtan CHP	2	2028	2028
Gimpo CHP	1	2026	2024
Gunsan	1	2027	2026
Gwanggyo CHP	1	2024	2024
Gwangyang	1	2029	2031
Gwangyang	2	2029	2031
Hanam CHP	1	2028	2028
Hanlim	1	2023	2023
Hwasung CHP	1	2025	2027
Ilsan	1	2023	2023
Ilsan	2	2023	2023
Incheon	1	2024	2024
Incheon	2	2025	2024
Incheon	3	2025	2024
Incheon Airport	1	2023	2023
Jeju	1	2025	2025
Jeju	2	2025	2025
Mokdong CHP	1	2023	2023
Mokdong CHP	2	2023	2023
Naepo Green Energy	1	2026	2025
Nonhyun CHP	1	2023	2023
Nowon CHP	1	2023	2023
Ohsung	1	2027	2026
Osan CHP	1	2028	2028
Paju CHP	1	2025	2025
Pajumunsan	1	2031	2029
Pajumunsan	2	2031	2029
Pangyo CHP	1	2023	2024
Pocheon	1	2027	2027
Pocheon	2	2027	2027
Pocheon Cheonyeon	1	2033	2033
Posco	3	2023	2030
Posco	4	2023	2030
Posco	5	2025	2030
Posco	6	2025	2030
Posco	7	2031	2032
Posco	8	2032	2032
Posco	9	2032	2032
Pyeongtaek	2	2030	2028

Pyeongtaek gas	1	2023	2024
Pyeongtaek gas	2	2023	2024
Pyeongtaek gas	3	2023	2024
Pyeongtaek gas	4	2023	2024
Sejong CHP	1	2027	2027
Seoincheon	1	2023	2023
Seoincheon	2	2023	2023
Seoincheon	3	2023	2023
Seoincheon	4	2023	2023
Seoincheon	5	2024	2023
Seoincheon	6	2024	2023
Seoincheon	7	2023	2023
Seoincheon	8	2023	2023
Seoul	1	2028	2026
Seoul	2	2028	2026
Shinincheon	1	2024	2023
Shinincheon	2	2024	2023
Shinincheon	3	2023	2023
Shinincheon	4	2024	2023
Shinpyeongtaek	1	2033	2033
Songdo CHP	1	2024	2024
Suwan Energy	1	2024	2026
Ulsan	1	2023	2024
Ulsan	2	2023	2024
Ulsan	3	2024	2025
Ulsan	4	2030	2026
Wirye CHP	1	2033	2033
Yangju CHP	1	2025	2023
Yangsan CHP	1	2026	2025
Yeoju	1	2026	2027
Yeongwol	1	2024	2024
Youngnam	1	2032	2033
Yulcheon	1	2024	2030
Yulcheon	2	2030	2032

CLIMATE
ANALYTICS