Emissions from cycling of thermal power plants in electricity systems with high penetration of wind power: life cycle assessment for Ireland

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Abstract

The increase of renewable sources in the power sector is an important step towards more sustainable electricity production. However, introducing high shares of variable renewables, such as wind and solar, cause dispatchable power plants to vary their output to fulfill the remaining electrical demand. The environmental impacts relating to potential future energy systems in Ireland for 2025 with high shares of wind power were evaluated using life cycle assessment (LCA), focusing on cycling emissions (due to part-load operation and start-ups) from dispatchable generators. Part-load operations significantly affect the average power plant efficiency, with all units seeing an average yearly efficiency noticeably less than optimal. In particular, load following units, on average, saw an 11% reduction. Given that production technologies are typically modeled assuming steady-state operation at full load, as part of LCA of electricity generation, the efficiency reduction would result in large underestimation of emissions, e.g. up to 65% for an oil power plant. Overall, cycling emissions accounted for less than 7% of lifecycle CO_2, NO_x and SO_2 emissions in the five scenarios considered: while not overbalancing the benefits from increasing wind energy, cycling emissions are not negligible and should be systematically included (i.e. by using emission factors per unit of fuel input rather than per unit of power generated). As the ability to cycle is an additional service provided by a power plant, it is also recommended that only units with similar roles (load following, mid merit, or base load) should be compared. The results showed that cycling emissions increased with the installed wind capacity, but decreased with the addition of storage. The latter benefits can, however, only be obtained if base-load electricity production shifts to a cleaner source than coal. Finally, the present study indicates that, in terms of emission reductions, the priority for Ireland is to phase out coal-based power plants. While investing in new storage capacity reduces system operating costs at high wind penetrations and limits cycling, the emissions reductions are somewhat negated when coupled with base load coal.

Keywords

Life cycle assessment (LCA), energy modeling, power plant cycling, wind power, renewable energy system, emission factors

Highlights

- Environmental impact of a power system with a high share of wind power assessed
- Cycling emissions (start-up and part-load) included in LCA for the first time
- Increased cycling emissions did not negate benefits of higher wind penetration
- Energy storage combined with base load coal did not reduce system emissions
- Current life cycle assessment methodology underestimates power plant emissions

1. Introduction

Recent years have seen a steady development of renewables, in particular hydro, wind and solar power, which represented 18% of global electricity generation in 2011 [1]; by 2035 renewables are forecasted to account for almost one third of total electricity output [2]. In 2009 the Irish government set a target of 40% renewables in the electricity sector by 2020 [3], most of which will be provided by wind generation. Introducing increasingly high shares of variable and uncertain renewables such as wind and solar poses a challenge to the power system, where dispatchable power plants are requested to continuously increase and decrease their output to accommodate the variability of wind and solar generation, and to ensure that the electrical demand is always fulfilled.

Many studies in recent years have assessed the technical feasibility of power systems with large shares of renewables [4–11], nevertheless the environmental impacts for such systems have only partially been assessed, focusing predominantly on direct greenhouse gas (GHG) emissions at the power plant level. Tonini & Astrup [12] is the only study that the authors are aware of which assesses the environmental impacts over the entire life cycle of a power system with a high penetration of renewables. Life cycle assessment (LCA) is in fact mainly used today to assess the environmental impacts from single generation technology [13–17]. A key limitation to this approach is not contextualizing the power plant within the power system [18]: variable output power sources such as solar and wind generation may induce efficiency penalties in fossil power plants providing balancing reserves [19,20]. These penalties may result in higher GHG emissions due to greater fuel volumes being used and, additionally, air pollution control systems that mitigate other emissions, such as NO_x, may not operate optimally when the generator power level is rapidly changed, further increasing emissions [21]. A common approach within LCA is to identify the emission per unit of energy generated [22]; emissions induced by variable renewables through cycling of fossil power plants are, therefore, usually not included, and have only recently been discussed [9-11, 21, 23]. This study followed the approach outlined in [9-11], which analyzed entire energy systems and recognized that aggregation reduced both variability of wind power and cycling requirements of the dispatchable power plant fleet. However [9-11] only assessed direct emissions, i.e. at the power plant stack.

This study used LCA to assess the environmental impacts of an electricity system with a high penetration of variable renewables, in this case wind power. The island of Ireland (here simply referred to as Ireland) was used as a case study, and five possible portfolio scenarios for 2025 were modeled. Hourly energy modeling was used to quantify the operational consequences of having a high share of renewable sources in the power system, as suggested in [8,23,24]. Particular focus was placed on the "cycling" impacts for fossil fuel power plants which need to operate at partial load and startup/shutdown to ensure that the maximum contribution from renewable electricity is accommodated in the network and that the electricity demand is always fulfilled. These operational aspects are usually accounted for when looking at past scenarios – since actual power plant data is typically used – but are often neglected when modeling future scenarios – because the time resolution is not accurate enough or power plant technical constraints are not included in the energy modeling.

The objectives of this study were (i) to evaluate CO_2, NO_x and SO_2 emissions from possible future plant portfolios for Ireland in an LCA perspective, (ii) to investigate emissions due to cycling (how relevant were cycling impacts compared to the overall emissions, which power plant types were most affected, and how different power plant mixes influenced the overall emission due to cycling), and (iii) to evaluate the results of this study with respect to common approaches in LCA of electricity generation technologies.

2. Methodology

In LCA, potential environmental impacts associated with the life cycle of a product/service are assessed based on a life cycle inventory, which includes relevant input/output data and emissions compiled for the system associated with the product/service in question. The LCA modeling in this study followed the recommended ISO methodology [25,26], and is explained in the following sections.

2.1. Goal, scope and functional unit

The goal of the LCA was to assess the environmental impacts related to five possible future energy scenarios for Ireland. The functional unit of the study was "fulfilling the electricity demand in Ireland in 2025", corresponding to 41 TWh. Attributional LCA was used, since the focus of this study was to identify the environmentally relevant physical flows to and from a product/service's life cycle and its subsystems in a status-quo situation [27]. Three emissions were included in the study: CO_2, NO_x and SO_2, representing the main contributors to global warming, acidification and eutrophication from the energy sector [16]. Emission data were obtained as output from the power system modeling (see section 2.2.1). All additional effects "outside" the system and the functional unit was accounted by system expansion following common approaches for addressing multi-functionality within LCA [27].

Three main sources of impacts during the life cycle of a power plant were included in the modeling, as suggested in [16]: fuel provision (from the extraction of fuel to the gate of the plant), plant operation (direct stack emissions), and infrastructure (commissioning and decommissioning). Within power plant operation, the focus of this study was to identify the role of part-load and start-up related emissions.

2.2. Scenario definition

2.2.1. Power system modeling

Unit commitment and economic dispatch was completed for the Irish power system at an hourly resolution using PLEXOS for Power Systems® [28]. The modeling was performed using mixed integer linear programming, using the Xpress MP solver. Energy and reserves were co-optimized, minimizing the total generation cost for the system. Three categories of operating reserve were included in the optimization, with varying requirements for response time and duration [29]. The primary and secondary operating reserve (POR & SOR) requirements were set to 75% of the largest infeed, while the tertiary operating reserve (TOR) requirement was set to 100%. There was an additional requirement which accounted for load and wind power forecast errors, over the reserve activation period, in addition to forced outages [30]. This resulted in minimal increases in fast acting POR requirements, but larger increases in the slower reserve categories, and varied depending on the level of installed wind generation.

The optimization horizon in PLEXOS is flexible and user-defined, and was set here to 24 hours, with a further 24 hour look-ahead. This ensured that plant start-ups were scheduled appropriately for plants with high start-up costs. It also ensured that energy remained in the reservoir at the end of the day, depending on the future system needs, for any modeled storage plant.

Costs included in the objective function were fuel costs, carbon costs and start-up costs. Each generator was modeled with a number of constraints which included maximum and minimum generation levels, minimum up and down times, ramp rates and reserve response levels [31]. Figure 1 shows efficiency as function of the load for dispatchable power plants; each plant was modeled individually. A number of system constraints were also included to ensure system stability, which were based on the system operator's "Operational Constraints Update" [30]. Included within these system constraints was a system non-synchronous penetration (SNSP) limit, which bounded the fraction of demand which can be supplied by non-synchronous sources (i.e. wind generation and DC interconnectors) and could lead to wind curtailment at times of high wind generation. The comprehensive modeling and plant representation allowed for detailed analysis of plant cycling at future high wind penetrations, although the model was limited by the hourly resolution adopted which may potentially underestimate the plant cycling required.

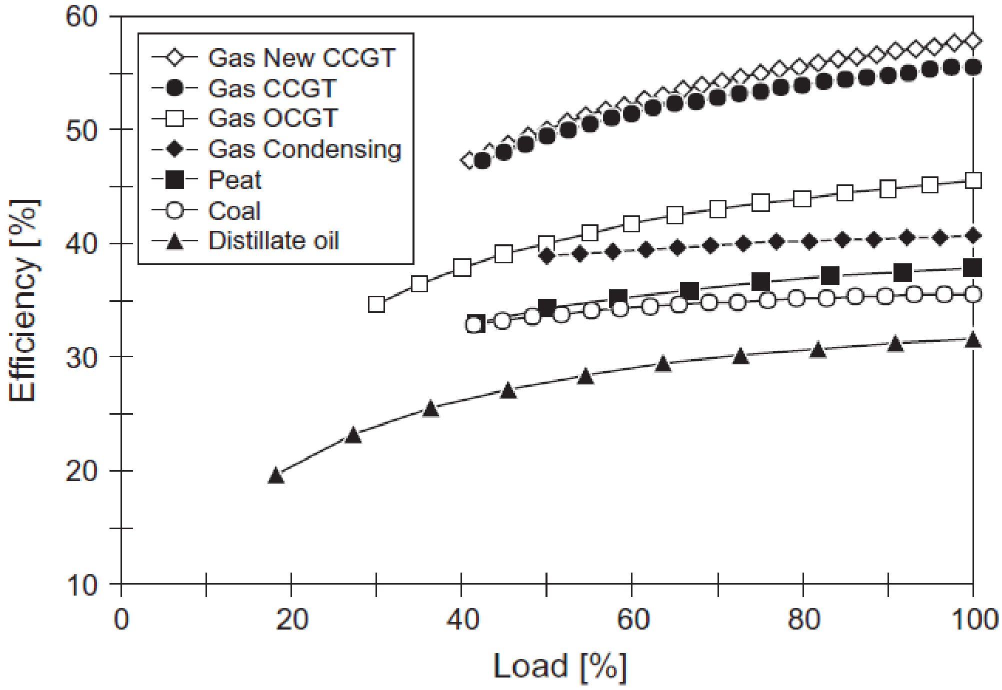

Figure 1. Power output from dispatchable generators as function of load (CCGT: Combined Cycle Gas Turbine; OCGT: Open Cycle Gas Turbine).

2.2.2. Test System

The base system was a possible future plant portfolio for the island of Ireland in 2025. The current Irish power system has considerable over capacity, so that much of the required (future) plants have already been built or commissioned. The system operator publishes the All Island Generation Capacity Statement annually [32] which estimates electricity demand and generation capacity for the following 10 years. The base system was based on the 2022 estimates, with a few additional retirements of older plants. Peak demand was assumed to grow by an additional 2.5% to 7.7 GW with a total electricity requirement of 41 TWh.

Demand profiles were based on measured data from 2009 which have been scaled appropriately. To generate the wind profiles, measured 15 minute data from 2009 for individual wind farms was used. This data was then scaled up on a regional basis, depending on the location of proposed wind farms which have received connection offers. The data was then time-shifted (20% by 15 minutes and 10% by 30 minutes), as an approximate representation of currently undeveloped regions to the east of existing wind farms based on the locations of proposed wind farm developments and prevailing wind directions on the island. It also served the purpose of smoothing the aggregate profile, which occurs as additional wind farms are added to a region [33,34]. The hourly profiles were achieved by averaging the 15 minute data.

The bulk of the capacity on the system was provided by gas plants (Open Cycle Gas Turbines, OCGTs; and Combined Cycle Gas Turbines, CCGTs), with additional plants fuelled by coal, peat and hydro generation (including one large pumped hydro plant). A breakdown of capacity by plant type can be found in Table 1. Base-load was provided by the coal and peat plants and the new CCGT plants. Mid-merit plants in the system largely consisted of older CCGTs, often originally designed for base-load operation. Peaking capacity was provided by OCGTs and distillate oil plants. Due to the high levels of installed wind generation (and hence high net load variability), all plant types provided a degree of load-following while on-line.

Fuel prices were taken from the central scenario in [35], and a carbon price of €30/Mg CO_2 was assumed [4]. Alternative fuel and carbon prices could change the merit order of the modeled plant, resulting in different emission levels for the scenarios explored.

The power system in Ireland is an isolated AC system, connected to Great Britain (GB) via two 500 MW DC interconnectors. The GB system was modeled as a single generator with 12 different heat rates which vary depending on the season and time of day, representing a generation merit order as outlined in [29], which closely follow price movements on the GB system. The GB model allows for realistic interconnector flows to be generated, with emissions for the GB system calculated separately.

2.2.3. Scenarios for 2025

The included scenarios were intended to represent realistic portfolios for the Irish system circa 2025. Scenarios 1, 2 & 3 had identical conventional plant portfolios, with the only difference being the level of installed wind capacity. Scenarios 1, 4 & 5 all possessed the same installed wind capacity. Scenario 4 replaced the coal plant with CCGT plants of comparable capacity, while scenario 5 had an additional flexible storage plant included. Power plant capacities for each scenario are reported in Table 1, and Figure 2 shows the power generation. As discussed in Section 2.2.2, much of the capacity required to meet the 2025 demand has already been built. As such, the plant portfolio for each of the scenarios considered remains largely unchanged.

Scenarios 1-3 consisted of the same fleet of thermal plants, with three different levels of installed wind generation capacity. Scenario 1 (Base) had an installed wind generation capacity of 6 GW, in-line with the 2022 predictions from [32]. Scenarios 2 and 3 explored alternative scenarios for installed wind capacity. At the end of 2013 there was just over 2 GW of installed wind capacity on the island of Ireland. There is a degree of uncertainty as to the capacities which will be achieved by 2025. Final figures will depend on government policy (particularly post 2020) and the economic and market conditions for private wind farm developers.

One of the largest electricity generating stations in Ireland is a coal fired, 855 MW, station which is due to be decommissioned around 2025. The base scenario assumed that the original station's life is extended and remains in place. Scenario 4 assumed that the station is replaced by three 300 MW CCGTs. While this is a poor choice in terms of fuel diversity for Ireland, it is a viable option in terms of capital and operating costs for most fuel price scenarios [36].

Increased wind generation penetrations causes increased cycling of conventional thermal plants. One way to moderate the cycling burden is to introduce flexible storage, which was explored in scenario 5. The storage plant modeled is extremely flexible (0 MW minimum charging and discharging levels) and efficient (80% round trip efficiency, a typical value from the range of efficiencies of existing storage technologies [37]. It was also assumed that the plant could provide 100% of its 100 MW capacity in fast acting reserve. It had an energy storage capacity of 0.5 GWh.

Import and export were rather constant on a yearly basis for all scenarios, with 1,500-1,800 GWh/y and 1,800-3,000 GWh/y, respectively. Net values varied between 100 GWh net imports (Scenario 2) and 1,600 GWh net exports (Scenario 3).

Table 1. Scenarios 1 – 5. Power plant capacity in MW (CCGT: Combined Cycle Gas Turbine; OCGT: Open Cycle Gas Turbine). Bold values indicate changes from the Base scenario.

[MW]	Scenario 1 (Base)	Scenario 2 (Low Wind)	Scenario 3 (High Wind)	Scenario 4 (No Coal)	Scenario 5 (Storage)
Wind	6000	**4500**	**7500**	6000	6000
Gas CCGT	3053	3053	3053	3053	3053
Gas New CCGT	1335	1335	1335	**2235**	1335
Coal	855	855	855	**0**	855
Distillate Oil	577	577	577	577	577
Gas Condensing	419	419	419	419	419
Gas OCGT	349	349	349	349	349
Peat	346	346	346	346	346
Embedded Generation*	294	294	294	294	294
Pumped Storage	292	292	292	292	292
Hydro	216	216	216	216	216
Waste	77	77	77	77	77
New Flexible Storage	0	0	0	0	**100**

*Embedded generation includes non-dispatchable plants on the island of Ireland: CHP, biomass/landfill gas and small-scale hydro

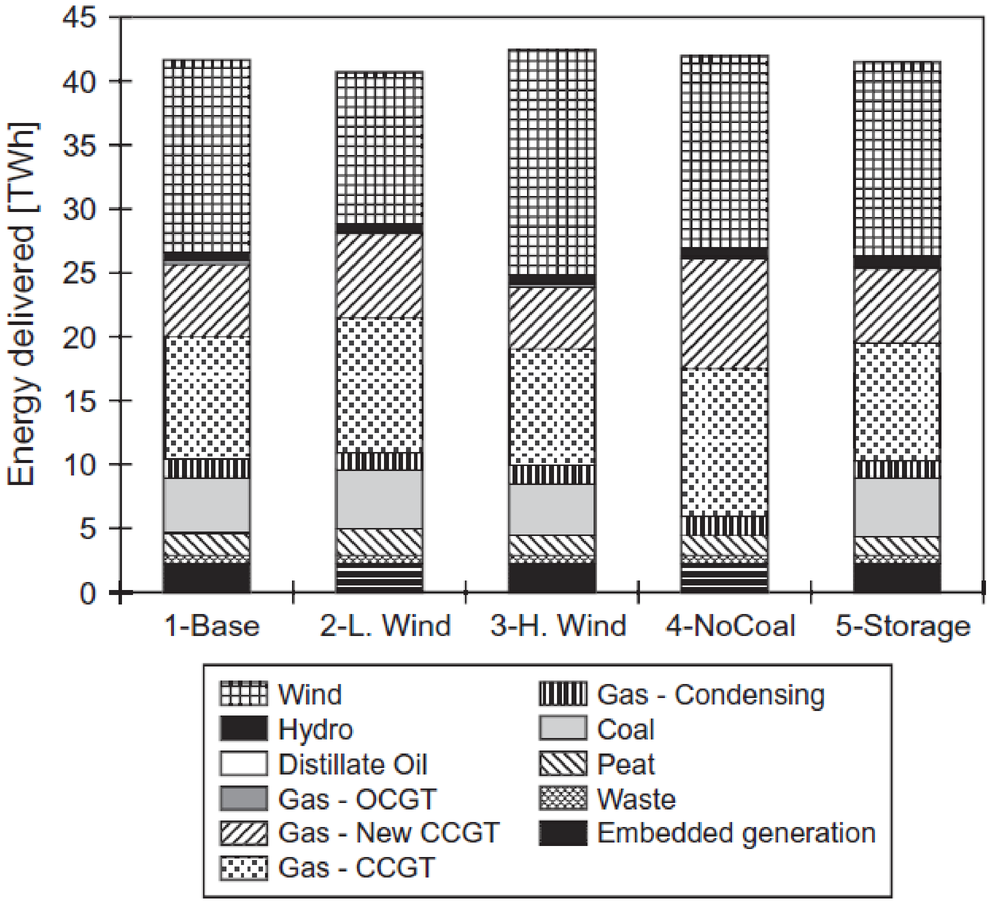

Figure 2. Scenarios 1 – 5. Power generation (CCGT: Combined Cycle Gas Turbine; OCGT: Open Cycle Gas Turbine).

2.3. Life-cycle inventory data

Each power plant included in the analysis was modeled separately. Data for fuel provision (natural gas, peat, oil and coal) were retrieved from the Ecoinvent database [38]. A zero burden approach was applied for waste, following common practice within waste LCA [39], and therefore no impacts were associated with provision of waste.

Regarding power plant operation, for combustion processes emissions at the power plant stack were calculated based on emission factors per unit of fuel input, as suggested by IPCC [40]. Average data for power plants in Ireland were used (Table 2) [41]. Fuel input for power production and startup of power plants were provided by the PLEXOS model for each unit at an hourly resolution. Three values were calculated for each power plant in each hour:

(i) *Max_efficiency* considers the emission from the power plant assuming steady state operation at optimal generation level, when efficiency is at its maximum (i.e. at 80-100% load in Figure 1);

this value is relevant because it is the value usually applied in LCAs of power generation technologies.

(ii) *Part-load* is the difference between the emission calculated at *Max_efficiency* and the actual emission at the power plant due to cycling (i.e. producing electricity at partial load and consequently with sub-optimal efficiency).

(iii) *Start-up* includes emissions due to fuel combustion during start-up, without generation of electricity. An additional emission of NO_x and SO_2 due to sub-optimal flue gas cleaning at low temperatures during startup was included, following [9] and recalculated per unit of fuel used during startup (Table 3).

Impacts related to operation and maintenance of hydro and wind power plant were considered negligible, as previously documented in [16]. Waste-to-energy and embedded generation were assumed must-run, and therefore their power generation was equal in each scenario. For these technologies no data were available on cycling, and a fixed emission factor per unit of electricity generated was used [38].

Table 2. Emission factors for fuel combustion. Values per unit of fuel input.

Fuel	CO_2 kg/GJ	NO_x g/GJ	SO_2 g/GJ
Natural Gas	56.1	49.4	0
Coal	94.6	366	461
Distillate Oil	74.1	159	477
Peat	106	115	99.6

Table 3. Emission penalty for fuel combustion due to sub-optimal flue gas cleaning during startup. Values per unit of fuel used during start-up, without distinction among cold/warm/hot start [9] (CCGT: Combined Cycle Gas Turbine; OCGT: Open Cycle Gas Turbine).

Technology	NO_x g/GJ	SO_2 g/GJ
Gas CCGT*	149	0
Gas Condensing	0	0
Gas OCGT	67	0
Coal	95	147

* The same emission penalty was assumed for both old and new CCGT

Data related to infrastructures were linearly scaled from Ecoinvent data [38] according to the capacity for each power plant. Wind turbines were assumed to be 90% onshore and 10% offshore, in line with the 2022 predictions from [32].

To model import/export with Great Britain (GB), a 2025 electricity mix for GB was modeled based on projections from the British Department of Energy and Climate Change [42,43] and Ecoinvent technology data [38]. Using electricity mix for import/export is consistent with attributional LCA methodology [27]. Average life cycle emissions for the production of 1 MWh of electricity in GB in 2025 were calculated: 265 kg CO_2, 380 g NO_x and 285 g SO_2. These values carry uncertainty, but because of similar import in all scenarios this had limited influence on the results and were not further investigated.

3. Results and discussion

In this section the main results of the study are presented. Section 3.1 includes results for the LCA of the entire power system; section 3.2 focuses on the influence of a power system on the emission factors of its power plants; and section 3.3 presents a discussion where the approach used in this study is compared with the common approach used in LCA of energy technologies.

3.1. Irish power system

The life cycle emissions of CO_2, NO_x and SO_2 during one year of operation in Ireland in 2025 are shown in Figure 3. It can be seen that in this case CO_2, NO_x and SO_2 followed the same trend: the ranking of alternative scenarios being consistent across the three emissions. Stack emissions were the major source of emissions for all scenarios, followed by fuel provision, mostly owing to coal extraction and transportation. Infrastructures and power import/export provided negligible emissions. Must-run generators provided non-negligible emissions only for NO_x, mainly owing to stack NO_x emissions at waste incinerators.

Net import (annual import exceeding export) occurred only in scenario 2, while scenarios 1, 3, 4 and 5 resulted in net export. As the functional unit of the study was “fulfilling the electricity demand in Ireland”, only electricity consumed in Ireland was included in the system itself. Thus, in scenario 2 power imported from GB was included in the LCA modeling, leading to increased impacts. Any power exports provided additional effects outside the Irish system (avoided power generation in the GB system) and was modeled by system expansion, i.e. by accounting avoided generation by the corresponding saved emissions (negative values) and including these as benefits in scenarios 1 and 3-5. As previously stated, following the principles of attributional LCA [27], the electricity generation mix of Ireland and GB were used to account for export and import, respectively.

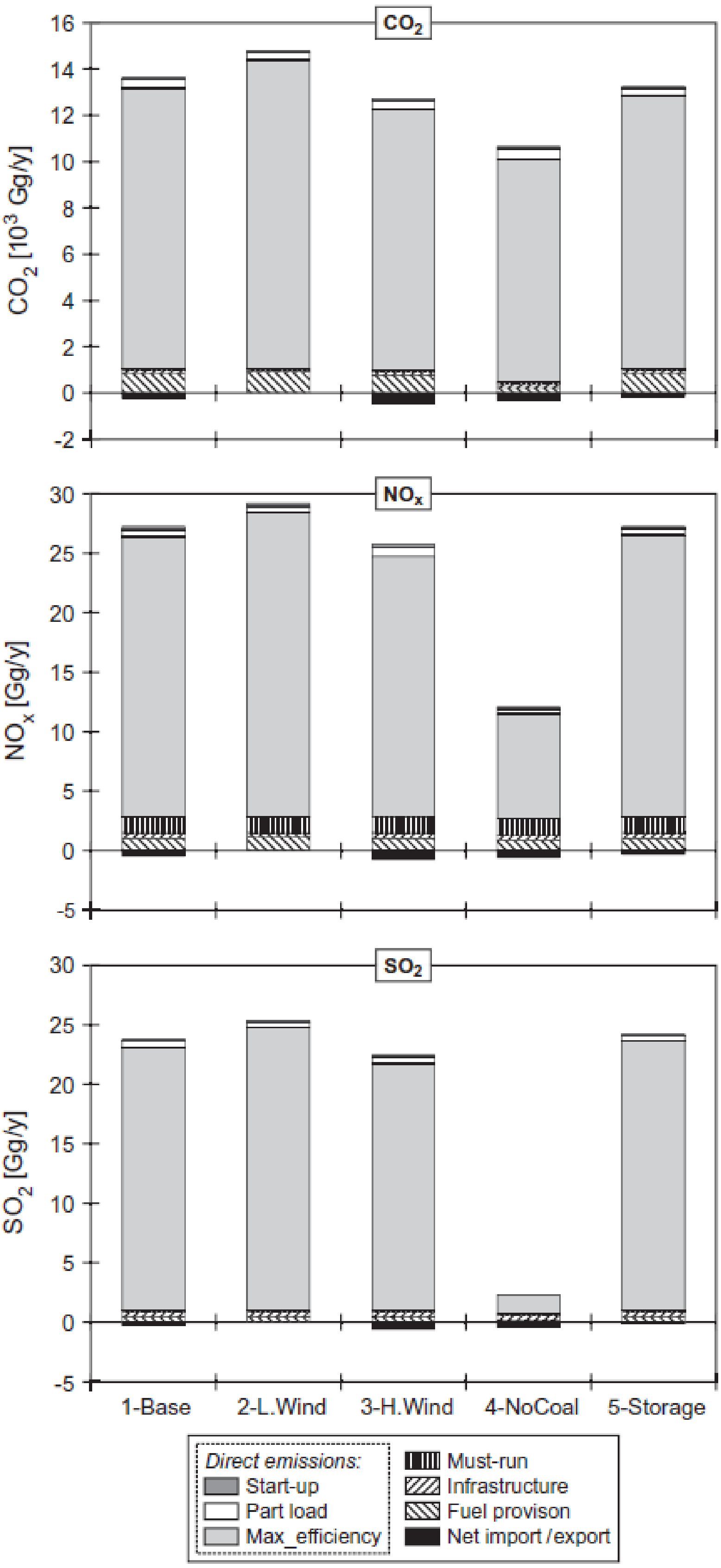

Figure 3. Life cycle emissions of CO_2, NO_x and SO_2 during one year of operation in Ireland 2025.

Scenario 4 (no coal) presented the lowest emissions, outperforming all other scenarios especially for NO_x (57% reduction compared to Base scenario) and SO_2 (91% reduction) owing to the phase-out of coal and its substitution with natural gas; for the same reason, CO_2 was also reduced, by 23%. Scenario 2 (low wind) was the only scenario with higher emissions than the base scenario, while Scenario 3 (high wind) presented slightly lower emissions to the environment than the base scenario, owing to the increased wind power produced and the consequent lower utilization of fossil-based power generators. In scenario 5 (storage), due to the additional storage capacity, power plants were requested to cycle less frequently – which lowered emissions – but, on the other hand, load was shifted from natural gas (in particular CCGT, mid-merit) to coal (base-load) (Figure 1), ultimately increasing emissions and compensating the benefits of storage; overall, this resulted in similar emissions in scenario 1 and 5. While a slight reduction was seen in CO_2 emissions, SO_2 emissions were seen to increase in scenario 5, although the reduced cycling has additional benefits in terms of operating and maintenance costs for conventional plants, and a significant reduction in the overall operating cost for the system as shown in [44]. The highly flexible storage system modeled for scenario 5 resulted in operating cost savings of 2% relative to the base system. This result highlights the benefit of additional flexibility on a system with high penetration from wind generation. Similar cycling reductions could also be possible with other forms of flexibility such as demand response. These results identified phasing out coal as the main priority to reduce CO_2, NO_x and SO_2 emissions from the power sector in Ireland. However, additional gas plants would have implications in terms of fuel diversity. Other coal plant replacement options, such as a carbon capture and sequestration (CCS) plant, could provide an additional improvement in emissions reduction, although these scenarios have not been explored here.

In all scenarios except scenario 4, stack emissions represented 93-95% of CO_2 emissions, 90-91% of NO_x emissions, and 96-97% of SO_2 emissions, with coal combustion being the largest source, in particular, for NO_x and SO_2. Conversely, in scenario 4 emissions were spread more across the lifecycle, with stack emissions accounting for only ≈80% of the life cycle emissions of NO_x and SO_2. In this scenario, fuel provision and infrastructure played an increasingly important role, confirming the importance of life cycle assessment as a tool to avoid “problem shifting” among different phases of the life cycle. CO_2 emissions remained dominated by stack emissions, owing to the high share of fossil fuels used.

3.2. Emissions from cycling

Emissions from cycling (total of part-load operation and startup) accounted for 2.7-5.0% of life cycle CO_2 emissions, 2.9-6.4% for NO_x and 2.2-3.6% for SO_2 in the five scenarios considered. Emissions due to part-load operation were 2 to 6 times higher than those from start-up. This is consistent with [10], and in contrast with the findings of [11], highlighting how cycling emissions are specific to each power system. In the current study, not accounting for cycling emissions would not have changed the ranking of the alternative scenarios. On the other hand, neglecting these emissions would have resulted in an underestimation of the emissions, e.g. corresponding to 330-510 Gg/y CO_2. Some technologies faced more cycling operation than others: yearly emissions from distillate oil power plants, for example, resulted in 26-76% higher values than their estimation based on optimal working conditions. A discussion on single technologies is presented in Section 3.3. In conclusion, it is shown that cycling emissions are not negligible – they should be considered when assessing the environmental performance of power systems with a high share of renewables – but they do not overcome the benefits of increasing wind penetration.

Analyzing scenarios 1-3 it was seen how the wind capacity influenced the operation of dispatchable power plants, and consequently their emissions. Using CO_2 as an example, cycling emissions increased from 382 Gg/y in scenario 2 (29% wind power as fraction of energy delivered), to 445 Gg/y in scenario 1 (36% wind), and to 489 Gg/y in scenario 3 (41% wind). The same pattern could be seen for NO_x and SO_2. Scenario 4 is particularly interesting, because phasing out coal is a key step towards 100% renewable energy systems. For example, Denmark has a 100% renewable energy system target by 2050 and plans to phase out coal by 2030 [45]. Therefore, this scenario could represent a future transition phase for any power system shifting towards renewable sources. In this case cycling emissions represented 5.0%, 5.1% and 2.9% of life cycle CO_2, NO_x and SO_2 emissions respectively. In scenario 5, adding storage capacity proved to increase wind penetration and reduce cycling: this scenario had in fact the lowest CO_2 and NO_x emissions from cycling of all five scenarios, with values similar to scenario 2 (with 29% of the power from wind generation) despite wind producing 36% of the electricity. It should be noted though that this benefit was offset by higher emissions from other power plants – shifting from mid-merit gas CCGTs to more polluting base-load coal. This happened because storage accumulates energy when it is produced at its lowest price (i.e. from coal units) and discharges when the price is higher (i.e. displacing gas). Thus the benefits of cycling reduction due to increasing storage cannot be fully realized if not coupled with shifting base-load electricity production to a cleaner source than coal.

Based on existing data in literature, cycling emissions might either not be accounted for or inconsistently accounted for when performing LCA of future energy systems [9-11, 21, 23]. Using LCA on single technologies refers to their optimal working conditions, completely disregarding emissions from cycling. On the other hand, databases such as Ecoinvent [38] report average emissions from years of operation, therefore including part load operation, but referring to past years. In such databases the emissions from a power plant are specific to the power system context, and the emission inventory may not reflect what might happen in a different power system, when subject to different operating regimes. Both solutions appear unsuitable for modeling future power systems. From the results of this study the authors highlight the effectiveness of the IPCC approach for GHG accounting – emission factors based on unit fuel input – and suggest using the same approach in LCA of energy systems.

3.3. Consequences on LCA of energy technologies

In this section only increased emissions due to part-load operation are discussed, since they were found to be much larger than those from unit start-up. As explained earlier, typically LCAs for generation technologies considers the power unit to be operating in steady state at maximum efficiency (full load). Table 4 compares the efficiency, CO_2 and NO_x emissions for each power plant type with the units operating at both *max_efficiency* and for the actual (unit commitment) range seen in this study. The efficiency and emission factors presented are based on the weighted average of the power production for each power plant type.

Table 4. Comparison between optimal and actual efficiency and CO_2-NO_x-SO_2 emissions at the power plants considered (CCGT: Combined Cycle Gas Turbine; OCGT: Open Cycle Gas Turbine).

		Values obtained with *max_efficiency* approach	Range identified within this study
Gas CCGT	Efficiency [%]	55.0	53.1 - 51.7
	CO_2 [kg/MWh]	368	383 - 395
	NO_x [g/MWh]	324	337 - 347
Gas New CCGT	Efficiency [%]	57.9	56.7 - 54.2
	CO_2 [kg/MWh]	349	356 - 375
	NO_x [g/MWh]	307	313 - 330
Coal	Efficiency [%]	35.3	34.6 - 34.2
	CO_2 [kg/MWh]	965	985 - 997
	NO_x [g/MWh]	3,737	3,815 - 3,861
	SO_2 [g/MWh]	4,703	4,802 - 4,860
Distillate Oil	Efficiency [%]	31.9	24.6 - 18.8
	CO_2 [kg/MWh]	839	1,119 - 1,475
	NO_x [g/MWh]	1,800	2,400 - 3,164
	SO_2 [g/MWh]	5,401	7,203 - 9,495
Gas Condensing	Efficiency [%]	57.2	56.2 - 54.1
	CO_2 [kg/MWh]	355	367 - 392
	NO_x [g/MWh]	312	323 - 345
Gas OCGT	Efficiency [%]	45.0	42.3 - 37.7
	CO_2 [kg/MWh]	450	477 - 536
	NO_x [g/MWh]	396	420 - 472
Peat	Efficiency [%]	38.1	37.5 - 37.2
	CO_2 [kg/MWh]	1,002	1,018 - 1,027
	NO_x [g/MWh]	1,089	1,106 - 1,116
	SO_2 [g/MWh]	941	956 - 965

On average during one year of operation, all power plants operated at an efficiency lower than the optimal value: distillate oil power plants and gas OCGTs were most affected, generating electricity with respectively 7-11% and 3-7% less efficiency than optimal, due to their role as peak-following. Base-load power plants, such as coal and peat, were required to cycle less, and so their efficiency was only 0.6-1% below optimal over one year. Mid-merit power plants, such as gas condensing and CCGT, had efficiency reductions respectively of 1.0-2.1%, 2.0-2.8% and 1.1-2.5% compared to their optimal generation level.

When using emission factors per unit of fuel input, emissions have an inverse relationship with efficiency. Within the peak-following power plants, the actual emissions were 32-65% higher than optimal for oil units, with the corresponding value being 6-19% for gas OCGTs. For mid-merit power plants, increased emissions ranged from 2 to 6%, while emissions from base-load units increased by 1.6-3.3%: the overlapping bounds for these two ranges were due to the differences in shape of the load-efficiency curves. For example, a CCGT is required (and has the ability) to ramp quickly and frequently, but this ramping capacity is combined with a steeper power curve than that for coal (Figure 1). In other words, CCGTs are more affected than coal plants in part-load operation, but owing to the inability of the latter to ramp quickly, CCGTs are required to act as mid-merit units.

In summary, power plant emissions are dependent on the role that individual power plants play in the power system. This aspect will assume increasing relevance in future systems, where wind and solar power will play an increasingly important role. Due to their variability, these sources will tend to increase cycling in thermal power plants. Following the current methodology, LCA's of electricity generation technologies are not always fully comparable, owing to the different roles that individual power plants can play in the system. On this basis, we suggest that future LCA studies should: (i) identify the typical role of a power plant (base-load, mid-merit or peak-load); and, if possible, (ii) provide realistic emission factors accounting for the expected operation of the power plant, i.e. estimating an “average efficiency during operation” rather than using the optimal efficiency. Alternatively, the plant efficiency should be expressed as function of the load (as shown in Fig. 1), to accurately model each unit in the power system. Clarifying a power plant’s role in the system would improve comparability between LCA studies and allow appropriate interpretation of technologies belonging to different categories, since two units providing different services (i.e. peak- and base-load) are not interchangeable and therefore are not fully comparable. In other words, power plants that possess a greater ability to cycle should be acknowledged for the additional flexibility they provide to the power system.

4. Conclusions

LCA was combined with hourly modeling of future power systems with a high penetration of variable renewables, such as wind power. The case study chosen was the island of Ireland in 2025, which allowed estimating cycling emissions, due to part-load operation and start-ups. It was found that cycling emissions had an increasing trend with an increase in wind power. Conversely, introducing new storage capacity limited cycling issues, which was clearly important in terms of the operational and maintenance costs for thermal plants and also in terms of the operating costs for the system. However, achievable emission reductions were dependent on the plant portfolio, particularly the base load plants which typically saw an increase in capacity factor upon the introduction of bulk storage. From these results the priority for Ireland, in terms of emission reductions, seems to be phasing out coal plants, rather than investing in new storage capacity to increase wind penetration and limit cycling.

Overall, emissions from cycling amounted to less than 7% of life cycle emissions for all portfolios: their contribution was therefore limited, and for this case study cycling emissions did not change the ranking of scenarios. Nevertheless, this contribution should not be ignored in LCA studies, and we recommend including cycling emissions in future studies, especially if the objective of the modeling is to increase the penetration of wind or solar power. Overall, using emission factors per unit of fuel input rather than per unit of power generated is highly recommended for future LCA studies.

Emissions from cycling may be relevant also for LCA of individual power generation technologies. Currently in literature emissions are estimated typically assuming steady state operation at full load. Clearly, this is not representing real-life operation of the power plants. In the scenarios presented here, all power plants had an average yearly efficiency lower than the optimal value. In particular, load following power plants had efficiencies up to 11% lower than optimal, which resulted in a potential underestimation of emissions by up to 65% for oil power plants, the extreme case. On the other hand, the ability to cycle is an additional service that a power plant can provide to a power system. It can, for example, enhance the penetration of wind power and reduce the need for curtailment at certain times. For a coherent assessment, the authors therefore suggest including the expected cycling emissions from a power plant, and only comparing units with a similar role – load following, mid merit, or base load.

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