INTERNATIONAL BUILDING PERFORMANCE SIMULATION ASSOCIATION ENGLAND

Proceedings of BSO-V 2020
5th Building Simulation and Optimization Virtual Conference
21-22 September 2020
Loughborough, UK

Integration of Ensemble Models with Power Systems Optimisation - Detached Dwelling Case Study

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Abstract

An integrated modelling framework has the capability to provide researchers with insights on the potential environmental and economic benefits of building-to-grid integration in a post-retrofit scenario. The current paper studies the cost-optimal integration of building envelope retrofits and power systems optimisation using Ensemble models representative of the existing (i.e., pre-1970) detached houses in Ireland. A simplified power systems model is introduced. The model is representative of future generation scenarios (2020, 2030 and 2050) of the electrical power system in Ireland. A previously introduced linear heuristic optimisation methodology is updated to account for multi-scenario power systems models. The paper shows that the decarbonisation targets of the detached house stock in Ireland are achievable using a combination of envelope retrofits and electrified space heating technologies. The paper also shows that the proposed methodology represents computational savings of 10.53x with respect of a brute force solution of the problem.

Introduction

Residential dwellings represent unique opportunities for societal decarbonisation, since 80% of residential end-use energy consumption is for space and domestic hot water heating (Asaee et al. 2018). One approach to decarbonise the Irish residential sector using current technologies consists of the efficient inclusion of energy conservation and efficiency measures, including the upgrade of heating systems (Dineen et al. 2016). Ahern et al. (2013) determined that building retrofit measures have the potential to reduce the heating costs and CO_2 emissions for detached rural houses built prior to 1979 by 65% (approximately 20% of the Irish domestic dwelling stock). Electrified space heating can potentially lead to further reductions in carbon emissions in the residential sector. If Energy Conservation Measures (ECM) and electrified heating systems are combined, the heating load requirements of buildings will be reduced, and thus space heating and domestic hot water can be supplied by electrified heat systems such as direct resistive heaters (DHR), storage heaters (SH) and heat pumps (HP).

From a power systems investment planning point of view, retrofitting building stock prior to electrification is imperative as it reduces the need to expand network and generation capacity (Mancarella et al. 2011). At a societal level, the emissions as a result of transferring heating loads from conventional fossil-based fuels to the grid have the potential to be minimised in future generation scenarios (e.g., 2050), assuming low-carbon (or entirely decarbonised) power systems and the use of more efficient space heating technologies (ECF 2010). However, emissions reduction depends on the electricity generation portfolio and how it is operated. As such, electrified heating demand and the power system should not be studied in isolation. Hence the importance of the integrated building-to-grid models. Residential archetypes developed in Building Energy Performance Simulation (BEPS) environments are potentially useful for this task, as they allow for a high-fidelity numerical representation of thermal transient dynamics needed to quantify the potential of load shifting in residential dwellings. However, BEPS environments are not numerically compatible with power systems models, which are tipically expressed as (mixed integer) linear programs (e.g., Patteeuw et al. (2015)).

One alternative approach to overcome this limitation consists of using BEPS tools to generate synthetic building performance data as an input to power systems optimisation tools. Wu et al. (2017) simulated energy demand associated with building archetypes for a Swiss village. The archetypes were developed using the EnergyPlus building simulation environment. Electricity demand profiles, extracted from the archetype, were optimised in an energy hub optimisation context (i.e., a multi-energy systems environment). One potential disadvantage of such a sequential approach is the omission of building flexibility (i.e., storage in building fabric) and electricity grid flexibility requirements (e.g., wind energy integration). In the aforementioned context, BEPS are unable to adapt to dynamic events occurring in the power systems model (e.g., availability of variable generation or demand response events). Hence the interest in developing building-to-grid integration mechanisms that capture the dynamics of BEPS thermal performance.

Ensemble Calibration (Andrade-Cabrera et al. 2017) is an automated model calibration methodology which identifies a cluster of lumped parameter building energy models (denoted Ensemble models) using an archetype building energy model. Each lumped parameter building energy model represents an ECM configuration (i.e., a combination of ECMs). In Andrade-Cabrera et al. (2020), a methodology was introduced to seamlessly integrate

Ensemble models with power systems models in a cost-optimal manner for retrofit decision-making. It was shown that, for a fixed price signal, the proposed optimisation methodology was capable of identifying a cost-optimal solution to the integrated building-to-grid retrofit decision-making problem while providing favourable computational advantages with respect to an alternative brute force solution. The current paper expands on Andrade-Cabrera et al. (2020) to demonstrate the cost-optimal integration of retrofit decision-making and power systems optimisation towards the cost-effective decarbonisation of the residential stock in Ireland. Pre-retrofit dwellings with oil and natural gas boilers are replaced with electrified heating. The proposed methodology identifies the cost-optimal ECM configuration and space heating technology upgrades while computing the impact of aggregated electrified space heating load in post and pre retrofit scenarios.

The current paper is organised as follows: First, the detached house archetype model used as a case study is briefly described. Then, a simplified power systems model is introduced. Both the archetype model and the power systems model are connected using a *system-wide cost-optimal ECM decision making* formulation, which considers potential savings in electricity generation post retrofit. The proposed methodology updates the optimisation methods introduced in Andrade-Cabrera et al. (2020) to consider a multi-scenario power systems model (2020, 2030 and 2050). Finally, the paper analyses the impact of large-scale retrofit measures on power systems operations and investment planning.

Case Study: Detached House Archetype

The detached house archetype model is comprehensively described in Neu (2016) and AECOM (2013) (see Figure 1). The archetype features double glazing windows (u_{win} = 2.88 W/m^2K , g_{win} = 0.759), heavy solid wall construction (U_{value} = 2.27 W/m^2K), an insulated ceiling (U_{value} = 2.37 W/m^2K) and an infiltration rate of 0.67 ACH. Two active occupancy periods are observed in accordance with the Dwelling Energy Assessment Procedure (DEAP) v3.2.1 (SEAI 2012): 7 AM to 9 AM and 5 PM to 11 PM, where thermal comfort is maintained. Weather is assumed to correspond to the IWEC2 Dublin weather file (ASHRAE 2012).

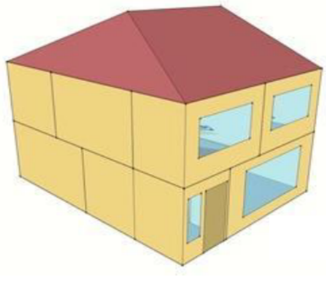

Figure 1: BEPS archetype model (Neu 2016).

Table 1 summarises energy data associated with Irish building stock (detached houses) used in the current work. In Neu (2016), it was estimated that the known number of existing (i.e., pre-1970) detached houses without electrified central heating to be 242,746. From census data (CSO 2016) it can be estimated that 46% of these dwellings use oil as a heating fuel, and 32% of these dwellings use gas as a heating fuel. The heating load of the detached house archetype is estimated to be 23,237 kWh/year (Andrade-Cabrera et al. 2020). This base load is used in the current analysis to approximate the energy requirements of the dwellings. The natural gas and oil boilers are modelled with efficiencies of 80% and 90%, respectively as per AECOM (2013). The annual running costs are calculated using the domestic energy costs provided in SEAI (2018a). The cost per kWh of oil for residential space heating purposes is 8.56 c/kWh. In the case of natural gas, the reference price is 6.49 c/kWh (Band D2). The emission factors were taken from SEAI (2018b), which for oil is 263.9 gCO2/kWh and for natural gas is 204.7 gCO2/kWh. Table 1 shows that the expected annual emissions for the selected buildings (189,342 dwellings) corresponds to 1.27 MtCO2/year.

Table 1: Irish building stock data (detached house)

Fuel	Dwellings	Energy [kWh]	Cost [EUR]	Aggregated Emissions [MtCO2/year]
Oil	111,664	29,046	2,486	0.86
Gas	77,678	25,819	1,676	0.41
Total	189,342	-	-	1.27

Power Systems Model

The simplified power system model features only two electricity generator types: the first represents electricity generation using conventional fuels (e.g., coal, natural gas, etc.), whereas the second represents wind power generation. The model allows for the estimation of fuel costs, carbon emissions and wind curtailment such that the interdependencies of the electrified space heating load and power system generation can be taken into account. The current paper considers three future electricity generation scenarios (2020, 2030 and 2050) as part of the same power systems model. The scenarios account for future base load demand and the increment in wind power penetration expected in future low-carbon electricity grids. The generation costs $GenCosts$ associated with the combined electricity demand (i.e., base load and electrified heating) for a given scenario is defined by the relationship:

$$GenCost_S = \lambda_S \sum_{k=1}^{NH} g_{k,S}\pi_S \quad (1)$$

where λ_S represents the number of conventional generators required to satisfy the combined electricity demand under scenario $S = \{2020, 2030, 2050\}$, NH represents the simulation horizon (in hours), $g_{k,S}$ is the average power output associated with conventional generation (MW) integrated over the kth hour and π_S (EUR/MWh) represents the generation cost for a particular scenario. The generation costs π_S are determined by the relationship:

$$\pi_S = Cost_{Fuel,S} + Cost_{CO_2,S} \quad (2)$$

where $Cost_{Fuel,S}$ represents the fuel costs (EUR/MWh) and $Cost_{CO_2,S}$ the carbon costs (EUR/MWh) associated with conventional generation, for a given scenario S.

Power generation is subject to the hourly power balance

$$\lambda_S g_{k,S} + w_{k,S} = \gamma P_{k,S} + D_{base,k,S} \quad (3)$$

where w_k is the wind power output (MW), γ is an aggregation multiplier (i.e., the number of houses being considered for a given archetype model), P_k is the electricity power demand associated with electrified space heating (MW) and $D_{base,k}$ is the electricity base load (MW). Conventional power generation is also constrained by the maximum capacity generation per generator as follows:

$$0 \leq g_k \leq g_{max} \quad (4)$$

where g_{max} is the maximum generation capacity (MW).

Wind power output is constrained by the System Non-Synchronous Penetration limit (SNSP), which is an indicator of the maximum level of non-synchronous generation (wind and interconnection) allowed in the AIPS system (EirGrid and SONI 2015) as follows:

$$w_k \leq SNSP\left(\gamma P_k + D_{base,k}\right) \quad (5)$$

Wind power generation is also constrained by the maximum available wind power W_{av}, given as:

$$w_k \leq W_{cap} W_{av,k} \quad (6)$$

where W_{cap} is the installed wind capacity (MW) and $W_{av,k}$ is a realised wind-power availability time-series from SETIS (2017). The conventional generator selected for the current study is representative of a typical gas plant on the Irish system (Dublin Bay). The peak capacity of the selected generator is described in the PLEXOS energy model as 424 MW (CER 2016). Ramp rate constraints and minimum stable generation levels are disregarded at this stage of modelling, without loss of generality. It is acknowledged that the lack of operational detail impacts on the results (flexibility is over estimated, curtailment is underestimated). However, for systems with very high shares of variable renewable generation, the importance of temporal representation dominates (Poncelet et al. 2016). Hence, the implemented model, with high temporal detail (hourly resolution) and the SNSP constraint, allows for wind generation and conventional generation levels to be estimated. Table 2 summarises the power system modelling assumptions considered in the current paper. The proposed model accounts for three future fuel and carbon price projections (low, central and high) for each scenario S. Future carbon and fuel costs (2020, 2030 and 2050) were obtained from DBEIS (2016) and these costs have been used in other comparable studies to date (O'Dwyer 2018). The SNSP limit for the Irish power systems generation mix in a 2020 scenario is assumed to be 0.75, as it is consistent with current penetration targets for 2020 (EirGrid and SONI 2015).

Heat Pumps

Heat pumps (HP) deliver a heating load multiple times their associated power consumption. In the current paper, the efficiency of a heat pump, also known as Coefficient of Performance (COP), is given by the relationship:

$$COP_k = COP_{input} + m_{COP}\left(T_{amb,k} - 7\right) \quad (7)$$

where COP_{input} is an input parameter and m_{COP} is a temperature-dependent function that linearises the otherwise non-linear COP dependency with respect to outdoor temperature. This function has been obtained via regression using manufacturer data (GlenDimplex 2017). Adopting the linearised COP function with a reference design value of 7 °C allows for the pre-calculation of COP values and thus its implementation in a mixed-integer building-to-grid linear program. A hot water delivery set-point of 45°C is assumed for the HP, which can be met using either resized larger conventional radiators or fan-assisted convector radiators.

Table 3 defines the space heating technologies adopted in the current paper. Direct resistive heaters (DRH) and four heat pump (HP) technologies are considered (HP_1 to HP_4). The maximum heat output $Q_{heat,max}$ (W) for the four HP technologies was taken from a commercial manufacturer (Dimplex 2018). In the case of the HP devices, the maximum heating rate corresponds to design conditions specified by the manufacturer (7°C air set-point and 45°C water delivery set-point) (see Table 3). The value of the COP (and thus the consumed power) varies throughout the simulation as per Equation 7. Low-temperature fan convective radiators (Rad) have been selected to have a heat output identical to the heat output available for DRH replacement (i.e., 1,200 W, see Table 3). The costs are estimated to be 765 EUR/kW for device

Table 2: Power systems modelling assumptions

Model Parameter	Symbol	Units	Price Projection	Scenario		
				2020	2030	2050
Peak Base Demand	D_{peak}	MW	All	5,425	7,430	11,102
Installed Wind Capacity	W_{cap}	MW	All	7,050	7,794	10,017
Carbon Price Cost	$Cost_{CO_2}$	EUR/MWh	Low	11.10	20.10	88.00
			Central	15.00	33.33	88.00
			High	19.10	40.60	88.00
Fuel costs (Natural Gas)	$Cost_{Fuel,S}$	EUR/MWh	Low	3.24	5.16	5.16
			Central	4.39	8.25	8.25
			High	6.70	9.53	9.53

costs and 1500 EUR for installation costs as per GlenDimplex (2017). Radiator costs must be added as existing high-temperature water radiators are replaced. The technology costs do not include maintenance costs, which could be considerable for heat pumps. DHR is added as a technology option which, when combined with an HP, could help satisfy heating capacity requirements.

Table 3: Operational parameters and cost per electrified heating technologies

Device Model	P_{max} [W]	$Q_{heat,max}$ [W]	Device Cost [EUR]	Installation Cost [EUR]
HP_1	1,364	6,000	4,590	1,500
HP_2	2,195	9,000	6,885	1,500
HP_3	2,570	12,000	9,180	1,500
HP_4	3,810	16,000	12,240	1,500
DRH	-	1,200	200	100
Rad	-	1,200	530	100

System-Wide Cost-Optimal ECM Decision Making

Techno-economic retrofit decision-making analysis often assumes that forecasted energy cost savings are offset against capital investments in envelope and heating system ECMs costs (e.g., Asaee et al. 2017). This approach does not necessarily reflect the effects of aggregated retrofit decision-making at scale. A *system-wide* building-to-grid ECM decision-making framework seeks to identify the potential savings in forecasted electricity generation costs after retrofitted dwellings are added at scale. The current formulation focuses only on generation costs, but system-wide savings can also be identified in other areas of electricity generation, transmission and distribution such as capacity expansion or network upgrades. The current section shows how to calculate pre-retrofit (or business-as-usual) costs and the formulation of the system-wide cost-optimal ECM decision-making problem.

Business as Usual Costs

The costs for each electricity generation scenario $S = \{2020, 2030, 2050\}$ are computed using Equation 8 and the appropriate fuel and carbon price projections (Table 2). The generation costs between the scenarios S corresponds to a linear interpolation. The generation costs can be described by the following equations:

$$GenCosts_{yr+1} = GenCosts_{yr} + \Delta Yr_{1,2} \tag{8}$$

$$\Delta Yr_1 = \frac{GenCosts_{2030} - GenCost_{2020}}{10} \tag{9}$$

$$\Delta Yr_2 = \frac{GenCosts_{2050} - GenCost_{2030}}{20} \tag{10}$$

where ΔYr is the additional generation costs per year. ΔYr_1 is used for years between 2020 and 2030, whereas ΔYr_2 is used for years between 2030 and 2050. The business-as-usual costs BAU_{costs} for the pre-retrofit integrated building-to-grid model for N_{years} years of investment is defined by the equation:

$$BAU_{costs} = \sum_{yr=1}^{N_{years}} GenCosts_{BAU,yr} \tag{11}$$

subject to the generation costs and power system model dynamics (Equations 1-6) and the building model:

$$x_{k+1} = F_0\, x_k + G_0\, P_k + H_0 d_k, \tag{12}$$

$$T_{r,k} = Z x_k, \tag{13}$$

$$SP_k \leq T_{r,k} \tag{14}$$

where F_0, G_0 and H_0 represent the dynamics of a pre-retrofit building energy model, T_r is the room temperature, Z is a transformation matrix and SP is the thermostatic setpoint. $GenCosts_{BAU,yr}$ represents the business-as-usual generation costs for year yr, which in the current paper are interpreted as the generation costs if electrified heating is added with direct resistive heating prior to retrofits.

Retrofit Decision-Making for Individual ECM Configurations

The retrofit investment problem that minimises the generation costs for a single ECM configuration i while identifying the cost-optimal electrified space heating technology is expressed as the Net Present Value (NPV) problem:

$$NPV = \sum_{yr=1}^{N_{years}} \frac{GenCosts_{BAU,yr} - GenCosts_{ECM,yr}}{(1+r)^{yr-1}} - Envelope_{costs,i} - Tech_{costs,i} \tag{15}$$

where $Envelope_{costs}$ represents the investment in envelope ECMs and $Tech_{costs,i}$ represents the investment in technology ECMs (e.g., heating systems). The post-retrofit generation costs $GenCosts_{ECM,yr}$ corresponds to the generation costs when the building dynamics in Equation 12 features post retrofit dynamics (i.e., matrices F_i, G_i and H_i for one of the retrofitted models extracted using the Ensemble Calibration approach). A discount rate for investment r of 4% is selected. This discount rate is used by the Irish Government in cost-benefit analysis of public sector projects (CEEU 2012) and thus is suitable for the analysis of retrofit investments at scale, as shown in AECOM (2013). A solution via enumeration (or brute force) consists of solving the NPV returns estimation problem for every possible ECM configuration and identifying the configuration which maximises the NPV. The procedure guarantees the identification of a globally optimal solution. However, this approach becomes computationally intensive given the need to calculate multiple times the solution to the building-to-grid model.

Retrofit Decision-Making for Multiple ECM Configurations

As shown in Andrade-Cabrera et al. (2020), the retrofitted models extracted using an Ensemble model can be reformulated as the bi-linear building model dynamics which can be expressed as:

$$x_{k+1} = F_0 x_k + G_0 P_k + H_0\, d_k + \left(\sum_{i=1}^{n_{comb}} \bar{F}_i\, x_{lin} \delta_i + \sum_{i=1}^{n_{comb}} \bar{G}_i\, u_{lin} \delta_i + \sum_{i=1}^{n_{comb}} \bar{H}_i\, d_k \delta_i \right) \quad (17)$$

where the matrices $\bar{F}_i$, $\bar{G}_i$ and $\bar{H}_i$ represent the variation of dynamics of the ith retrofit configuration and decision variable δ_i represents one of the n_{comb} possible ECM configurations. The bi-linear problem is linearised using trajectories x_{lin} and u_{lin}. The NPV problem of the integrated building-to-grid investment model for multiple ECM configurations becomes:

$$NPV = \sum_{yr=1}^{N_{years}} \frac{GenCosts_{BAU,yr} - GenCosts_{\mathrm{ECM,yr}}}{(1+r)^{yr-1}} - \sum_{i=1}^{n_{comb}} Envelope_{Costs,i} \delta_i - Tech_{costs} \quad (18)$$

The variables that require optimisation are the heating load estimation variables u_k and the ECM decision variables δ_i. The ECM decision variables require a mutual exclusion constraint which can be expressed as:

$$\sum_{i=1}^{n_{comb}} \delta_i = 1 \quad (19)$$

Thus the integrated NPV problem (Equation 18) becomes a tractable (albeit suboptimal) MILP problem. The linearization trajectories x_{lin} and u_{lin} are obtained by solving the Business-as-Usual problem (Equation 11) for any ECM configuration. The reader is directed to Andrade-Cabrera et al. (2020) for a detailed explanation of the linearisation heuristic algorithm required to solve this problem.

Results

System-Wide Cost-Optimal ECM Configuration

The current section describes the results of applying the cost-optimal ECM decision-making and power systems integration mechanism in the case where only 25% of the target dwellings are retrofitted, under the assumption of a central fuel price projection (Table 2). An Ensemble model was computed for the detached house model archetype using the retrofit configurations described in Andrade-Cabrera et al. (2020), Table 1. The current paper uses the simplified retrofit index notation described in Andrade-Cabrera et. al. 2020, Table 2. Table 4 summarises five selected ECM configurations highlighted in Andrade-Cabrera et al. (2020) which will be used throughout the current paper.

Figure 2 identifies the system-wide cost-optimal ECM configuration via a brute force approach (i.e., the cost-optimal solution for each building-to-grid scenario). The cost-optimal configuration is the same as in Andrade-Cabrera et al. (2020) (i.e., {1,2,4,1} or 50 mm of internal insulation and 300 of ceiling insulation). The yellow circles correspond to ECM configurations where HP_2 (i.e., a 9 kW HP) is part of the cost-optimal solution.

Table 4: Selected ECM configurations

ECM Configuration	Description
Cost Optimal ECMs {1,2,4,1}	50 mm of internal insulation, 300 mm of ceiling insulation
AECOM (2013) {1,3,4,3}	100 mm of internal insulation, 300 mm of ceiling insulation, double glazing (argon filled uPVC windows)
Ahern et al (2013) {3,1,4,1}	200 mm of external insulation, 300 mm of ceiling insulation
Highly Efficient ECMs (e.g., {3,1,4,4})	200 mm of external wall insulation, 300 mm of ceiling insulation, triple glazing
Inefficient ECMs (e.g., {1,1,4,2})	300 mm of ceiling insulation, double glazing (uPVC windows)

The blue circles correspond to ECM configurations where HP_1 (i.e., a 6 kW HP) corresponds to the cost-optimal electrified heating configuration. The addition of low-temperature radiators has an impact on the potential NPV savings. All ECM configurations required 5 low-temperature radiators, except for the inefficient ECM configurations (shown in yellow circles in Figure 7.2), which require 7 - 8 radiators.

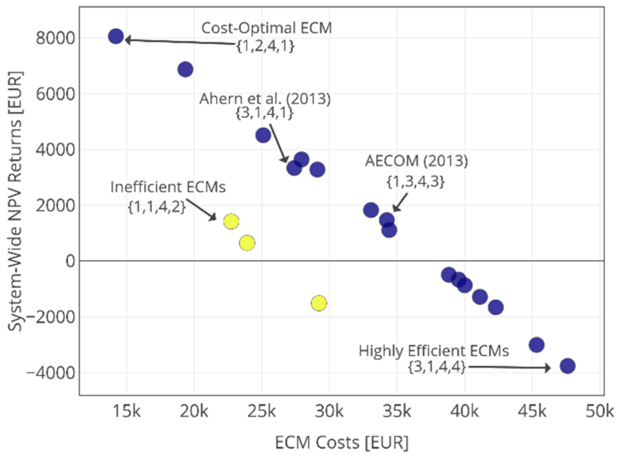

Figure 2: ECM costs vs system-wide NPV returns

The forecasted NPV returns are smaller than the expected results as forecasted with a fixed price signal (Andrade-Cabrera et al. (2020), Table 5). In that scenario, the end-user NPV savings with storage heating and a fixed price-signal yielded forecasted returns of 40,870 EUR. In the current scenario (system-wide NPV savings), the cost-optimal configuration {1,2,4,1} (i.e., 50 mm of internal insulation, 300 mm of ceiling insulation) results in NPV returns of 11,208 EUR. The key difference is that the study of Andrade-Cabrera et al. (2020) calculated NPV returns using a night-tariff price signal which accounts for electricity generation, transmission and distribution as well as commercial costs. Whereas, in the proposed system-wide formulation, only the expenditure in generation costs is considered. Generation costs accounted for only up to 41% of the retail price of electricity in 2015 as per SEAI (2017). Hence the lower forecasted NPV returns. Future generation scenarios will likely see a shift towards a higher share fixed costs and lower share of variable costs (primarily comprised of fuel costs), as systems shift from conventional generation to variable renewable generation. Such aspects are left outside of the scope of the current paper.

Figure 3 describes the carbon emissions reduction of each ECM configuration studied in the current section. The emission reduction is calculated as a percentage of the forecasted emissions as described in the reference scenario (1.27 GtCO2/year, as per Table 1). The dotted red line indicates the target emissions reduction (i.e., at least 80% decarbonisation in buildings by 2050, as per European policy (ECF 2010)). Figure 3 shows that a considerable number of ECM configurations (in grey sector) achieve a decarbonisation above 80% for all power system scenarios (i.e., 2020, 2030 and 2050). These configurations correspond to comprehensive ECM configurations featuring a mix of internal/external insulation, ceiling insulation and window glazing.

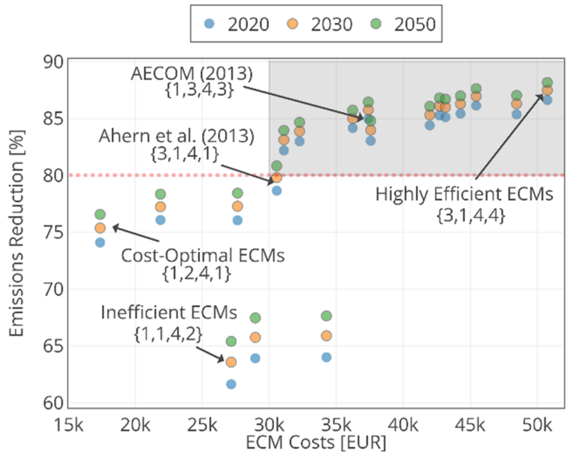

Figure 3: ECM costs vs emissions reduction

Highly efficient ECM configurations such {3,1,3,4} (i.e., 200 mm external insulation, 300 mm ceiling insulation and triple glazing) achieve 88% decarbonisation when a 6 kW HP is included as part of the ECM configuration. However, the retrofit costs associated with this configuration are evidently the highest. In fact, Figure 2 shows that this ECM configuration results in a loss (-3,760 EUR) over the investment period. On the other hand, the cost-optimal solution results in significant carbon abatement (76% emissions reduction) while resulting in the smallest ECM costs (17,368 EUR). These ECM costs are slightly less than one third than the costs associated with the highly efficient ECM configuration {3,1,4,4} (50,758 EUR). Interestingly, the ECM configuration identified in Ahern et al. (2013) (i.e., {3,1,4,1}) can reach 81% emissions reduction in a 2050 scenario, if the space heating requirements are met with a 6kW HP. The original study reported 65% emissions reduction when older inefficient oil boilers were replaced with more efficient condensing natural gas boilers.

Figure 4 describes the potential system-wide NPV savings after capacity expansion savings are accounted. The savings are computed post-optimisation as their integration within the proposed framework would require a formulation outside of the scope of the current paper (e.g., constraint programming with respect to generation capacity). In Heinen (2017), the approximate price of installing an efficient conventional generation plant was given as 0.8 million EUR/MW. The expected savings on capacity generation were computed for each electricity generation scenario (2020, 2030 and 2050) and the total expected savings (i.e., the sum of all scenarios) were divided by the number of houses (i.e., 47,335 dwellings, or 25% of the target stock).

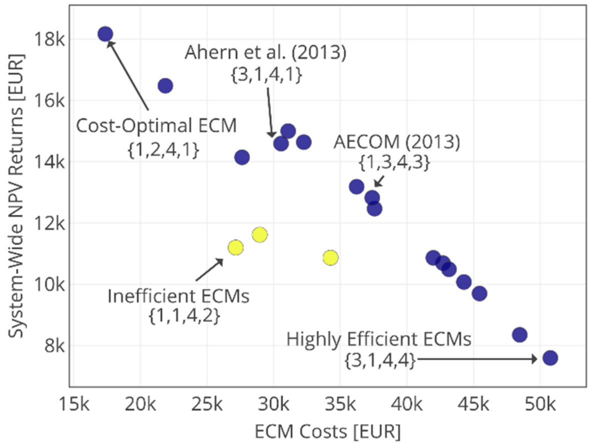

Figure 4: ECM costs vs system-wide NPV returns (capacity expansion costs included)

Hence the NPV savings shown in Figure 4 have two components: the savings associated with forecasted electricity generation (Figure 2) and the savings associated with reduced capacity expansion requirements. The cost-optimal configuration {1,2,4,1} results in the largest aggregated savings associated with capacity expansion and fuel savings (16,757 EUR). Table 6 shows that comprehensive ECM configurations have the potential to maximise capacity expansion savings. For example: an efficient ECM configuration such as {3,1,4,4} (i.e., 200 mm external wall insulation, 300 mm ceiling insulation and triple glazing) results in savings of 470.8 MEUR. This implies that no capacity has been installed in the system, as the baseline capacity costs were 470.8 MEUR (i.e., 100% savings). The cost-optimal solution (i.e., {1,2,4,1}, 50 mm of internal insulation and 300 mm of ceiling insulation) requires some minor level of investment on capacity, and thus only 411.7 MEUR of investment are deferred through this ECM configuration (i.e., 87% of potential savings). However, once fuel generation costs are added, the cost-optimal configuration remains the optimal solution of the system-wide ECM decision-making problem. Table 6 also shows an ECM configuration whereby only HP is considered as a retrofit measure. Table 6 shows that the large reduction in capacity expansion (72%) is driven by adopting efficient space heating technologies (i.e., HP) in lieu of resistive heaters. This finding underlines the importance of adopting HP in post-retrofit dwellings at scale.

Table 6: System-wide NPV returns with capacity expansion savings

ECM Configuration	Scenario			Total Capacity Expansion Savings [MEUR]	Expansion Costs per Dwelling [EUR]	System-Wide NPV Returns (Fuel Only) [EUR]	System-Wide NPV Returns [EUR]
	2020	2030	2050				
Cost Optimal ECMs {1,2,4,1}	401.1	10.6	0	411.7 (87%)	8,699	8,058	16,757
AECOM (2013) {1,3,4,3}	460.2	10.6	0	470.8 (100%)	9,946	1,465	11,411
Ahern et al (2013) {3,1,4,1}	455.3	10.6	0	465.9 (98%)	9,843	3,335	13,179
Highly Efficient ECMs (e.g., {3,1,4,4})	460.2	10.6	0	470.8 (100%)	9,946	-3760.42	6,186
Inefficient ECMs (e.g., {1,1,4,2})	367.1	10.6	5.8	343.4 (80%)	7,977	1,418	9,397
No Retrofit (HP only)	332.8	10.6	0	343.4 (72%)	7,254	-	-

Computational Performance and Convergence

Figure 5 shows the computational performance of the results shown in Figures 2 - 4. The speed-up of the linearisation algorithm when compared to a brute force approach increases when a power systems model is considered. In Andrade-Cabrera et al. (2020) it was shown that the linearisation algorithm results in a speed-up of 6.74 times, when a price signal is used as a proxy for a detailed power systems model. Figure 5 shows that the brute force algorithm results in 18.03 hours, whereas the linearisation algorithm is solved in 1.71 hours. Therefore, when a full detailed power systems model is considered, the linearisation algorithm results in a speed-up of 10.53 times (i.e., the proposed algorithm is 10.53 times faster than a solution via brute force).

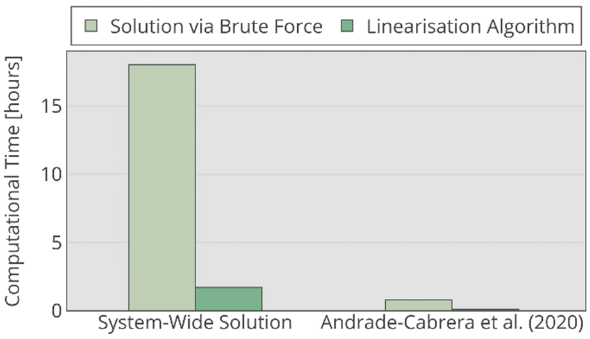

Figure 5 Computational performance of the proposed linearisation algorithm versus solution via brute force

Conclusions and Future Work

The current paper demonstrates that achieving the decarbonisation goals (i.e., 80-95% decarbonisation of the residential stock in Ireland) can be achieved with comprehensive envelope ECMs, coupled with electrified space heating retrofits. There is a considerable monetary gap between what is required at the societal level (i.e., highly efficient ECMs) and what is in the best interest of the end-user (i.e., the cost-optimal solution). Figure 2 suggest that a minimum investment of 30K in envelope ECMs and space heating technologies is required to achieve the emission targets. The cost-optimal solution achieves a significative carbon abatement (76% with respect to business-as-usual) and the required envelope ECMs are in line with what would be expected from end-users given the current level of incentives in Ireland.

The proposed system-wide cost-optimal ECM decision-making formulation benefits both end-users and electricity companies. Under the proposed framework, power systems operators could be able to integrate new flexible demand, with the potential for wind curtailment reduction and other potentially profitable benefits (e.g., distributed energy storage, deferral of network investment, provision of ancillary services).

The simplified power model is deemed sufficient for the purposes of the approximative calculations hereby introduced. While the generation costs are accurate and benchmarked against more detailed models (O'Dwyer 2018), the dynamics and diversity of the system are not fully captured, which may have some impact on the emissions results. A higher detailed model would allow for a better estimation of the emissions. The systematic handling of envelope uncertainties (e.g., window and wall U-values) as well as other uncertainties (e.g., energy prices, weather, retrofit costs) requires the development of methodologies beyond the scope of the current work. Uncertainties could be formulated as additive terms of a continuous-time Ensemble model (e.g., additional wall resistance for variations in wall U-value). Then, the model could be discretised for energy evaluation in a Bayesian framework (Andrade-Cabrera et al. 2018). Further work is also required in refining the Ensemble Calibration framework to improve tractability.

Acknowledgement

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 646116 (RealValue). The authors gratefully acknowledge the financial support of the Electricity Research Centre (ERC), University College Dublin, for this research.

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