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Complementarities of supply and demand sides in integrated energy systems

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***Abstract*— New small-scale demand-side technologies, such as micro combined heat and power technologies (µCHPs) and heat pumps (HPs), offer opportunities to increase system-wide efficiency. Furthermore, the technical and economic characteristics of demand-side technologies could also complement the supply side by providing system services, such as adequacy and flexibility, which are increasingly required due to high variable renewable energy penetration. A capacity expansion methodology that captures the interactions between the supply and demand sides is developed to find cost-optimal and adequate investment portfolios. For the case study presented, the integrated energy system leverages the technical and economic complementarities of different supply and demand-side technologies. As a result, system integration using demand-side technologies improves the value proposition for decentralization given that the technologies can provide heat demand, while also meeting electricity demand and providing adequacy and flexibility.**

***Index Terms*— Power system economics, power system planning, heating, energy systems integration, decentralization**

I. INTRODUCTION

THE existing energy system (e.g. oil, gas, electricity) is primarily a centralized supply infrastructure with one-directional energy flows to passive consumers. In such systems, large-scale extraction or conversion plants benefit from higher efficiencies at scale [1]. However, new small-scale generation technologies are now being installed on the demand-side motivated by a series of economic, technological and societal trends:

- Government subsidies and economies of scale in manufacturing of decentralized demand-side technologies have resulted in large cost reductions of technologies such as micro combined heat and power units (µCHP) and solar photovoltaics (PV) [2].
- Enabled by information and communication technology, the consumer is increasingly active in monitoring and controlling its energy production and usage [3].
- Large-scale supply infrastructure projects such as transmission grid expansion are hampered by lengthy and complicated planning and financing processes and local resistance to transmission [4].

New demand-side technologies are distributed and lead to decentralization of the energy system, which results in the convergence on the demand-side of different fuels (e.g. natural gas, electricity) and energy services (e.g. heating, cooling, transport). This could offer new system-wide efficiency improvement opportunities in particular by using multi-energy systems (MES) [5] or energy hubs [6] (e.g. µCHPs) to optimize the interaction between different fuels and services. Demand-side technologies can also be aggregated as virtual power plants that interact with the electricity market [7]. The growing deployment of variable renewable energies (VRE) (e.g. wind) increases the need for both adequacy and flexibility (i.e. ramping capability) [8].

In supply-side electricity design, optimal investments typically include a mix of technologies and/or fuels with different capital and operational cost structures to meet a varying demand. More capital-intensive technologies (e.g. coal power plants) are typically cheaper to run and are therefore base loaded, while less capital-intensive technologies (e.g. open cycle gas power plants) are more expensive to run and are consequently peak loaded. This premise implies that a range of technologies – a portfolio - is deployed to ensure cost-effective generation planning and this premise should be valid for demand-side technologies as well. A considerable difference between supply and demand-side portfolios is the larger number of small-scale players involved on the demand side. These players have a multitude of motivations not limited to profit-making, but also including, for example, the desire to be self-sufficient or green [9].

The existing literature has not shown the system-wide value of demand-side technologies, such as MES and HP, in an integrated energy system. Vuillecard *et al.* [10] show that µCHP units installed in the residential sector can support electric load management, but the analysis is limited to local impacts of 40 dwellings only and does not consider cost-optimal planning and interaction with large-scale supply plants. Capuder and Mancarella [11] demonstrate the potential of individual MES technologies to provide flexibility necessary to facilitate system balancing. However, cost-effective planning with a large population of MES and interaction with large-scale supply plants is not analyzed. Moeini-Aghtaie *et al.* [12] show how the deployment of MES in distribution systems can also improve reliability for certain operating strategies, but do not analyze system-wide

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complementarities between the demand and supply side. Other literature analyzes the interaction between supply and demand sides using least-cost optimization methods, but these studies focus solely on the electricity system. For example, You *et al.* [7] and Strbac *et al.* [8] analyze the interaction of the demand-side with the large-scale market by providing energy, as well as adequacy and flexibility. Other studies [13-15] are also limited to the electricity system only and do not consider residential heat, which represents roughly 80% of final energy use in buildings in Europe and 60% in the United States [16]. Residential heat is traditionally generated with natural gas-fueled decentralized technologies, such boilers.

The objective of this paper is to assess the role of demand-side technologies in an integrated electricity-residential heat system by capturing technical and economic complementarities, which are not covered in the existing literature. To establish complementarities in least-cost investment portfolios, a novel capacity expansion methodology is developed that represents the large-scale supply and distributed demand sides in the integrated electricity-residential heat system. This enables the discovery of cost-optimal planning portfolios that consider interactions/complementarities between technologies on the demand and supply sides, while technical adequacy and flexibility requirements are met. The electricity transmission and distribution networks are ignored to keep the study focused and tractable.

The paper is structured as follows: Section II presents the methodology and Section III the case study used. The results are discussed in Section IV, before concluding in Section V.

II. METHODOLOGY

The methodology presented in this paper covers the supply and the demand sides (e.g. µCHP and HP) of the integrated electricity-residential heat system (Fig. 1). The methodology is based on a least-cost optimization algorithm, which minimizes the total investment and operational cost for electricity and heat technologies (Eq. 1). The resulting optimal decision variables will determine the most efficient operating schedules and investment capacities for integrated electricity and heat technologies.

The demand and supply-side interactions as well as the interactions between different demand-side technologies are modelled in this paper. This is in contrast to Heinen *et al.* [17] where the interactions between demand-side technologies are not represented and the technology choice is not an endogenous decision variable of the model. The objective function (Eq. 1) of the proposed capacity expansion methodology includes both investment and operational cost for heat and electricity for technologies on the demand and supply sides over a time period, typically a year. Operational variability between time steps t is also captured, which is important in systems with high penetration of variable renewable energies (i.e. wind) and/or shares of electric heat given their variation over days, weeks and seasons [18].

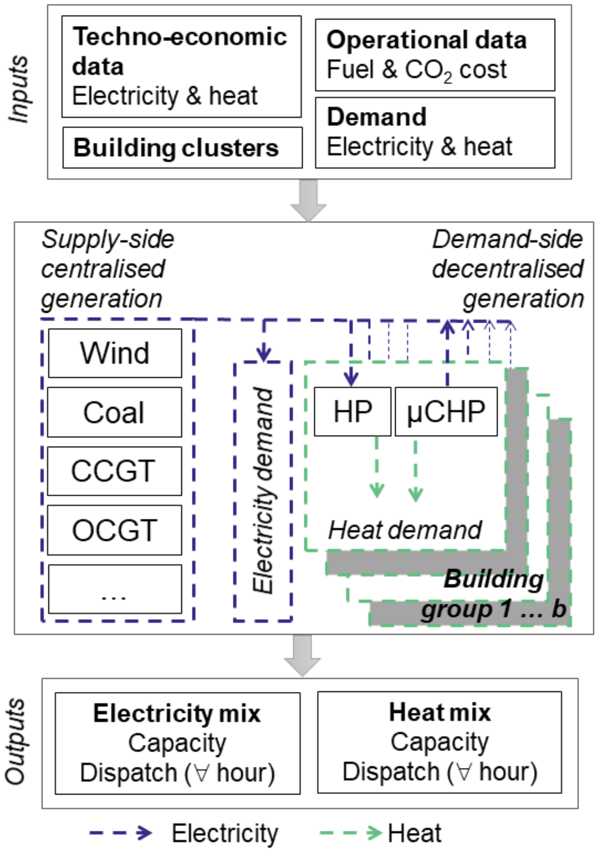

Fig. 1. Overview schematic of the methodology and the integrated electricity-residential heat system analyzed. Note: CCGT is a combined-cycle gas turbine and OCGT is an open-cycle gas turbine

$$\min \left(\sum_{ptech} \left(\underbrace{\left(\frac{IC_{ptech}^{elec}}{\alpha^{elec}} + OMFix_{ptech}^{elec} \right) \cdot C_{ptech}^{elec,new} +}_{investment \quad elec} \underbrace{\sum_{t=1}^{TS^{\max}} \left(\begin{array}{l} \dfrac{FP_{ptech}}{\eta_{ptech}} + OMVar_{ptech}^{elec} \\ + FCO_{2\,ptech}^{\;elec} \cdot CP \end{array} \right) \cdot E_{ptech}^{elec}(t)}_{opererational \quad cost \quad elec \quad (incl. \quad HP \quad heat)} \right) \cdot + \sum_{b} N(b) \cdot \left(\underbrace{\sum_{htech=HP,\mu CHP} \left(\frac{IC_{htech}^{eheat}}{\alpha^{heat}} \right) \cdot C_{htech}^{heat}(b)}_{investment \quad cost \quad heat} + \underbrace{\sum_{t=1}^{TS^{\max}} \left(\frac{FP_{\mu CHP}}{\eta_{\mu CHP}^{therm}} + \mathrm{FCO}_{2\,\mu CHP}^{\;heat} \cdot CP \right) \cdot \left(E_{\mu CHP}^{heat}(b,t) + E_{\mu CHP}^{heat,vent}(b,t) \right)}_{opererational \quad cost \quad \mu CHP} \right) \right) \tag{1}$$

The indexes t and b in Eq. 1 refer to time steps and building groups respectively. The parameters in Eq. 1 are specific investment cost IC, fixed and variable operation and maintenance (O&M) cost ($OMFix$ and $OMVar$), fuel prices FP, CO_2 emission factors FCO_2, carbon price CP, number of residential households *N(b)* for each building group *b*, and an annuity factor α. The indices *ptech* and *htech* refer to electricity and heat related technologies. Micro CHPs are included with heat-related technologies. Decision variables are both capital investment (capacity *C*) and dispatch (energy *E*) of supply and demand technologies. A superscript, *elec* or *heat*, is added to differentiate between electricity and heat-related decision variables. The decision variables are formulated in terms of output and are subject to constraints (Eq. 2 to Eq. 15) that are described in the following paragraphs.

The integrated system (Fig. 1) spans across two different scales: large-scale supply plants (MW scale) at national level and small-scale demand-side technologies at residential level (kW scale). Residential demand-side technologies are therefore aggregated into building groups, indexed *b,* that represent a number *N(b)* (e.g. thousands) of similar buildings with the same heating technology within each building group. This reduces the level of granularity and dimensionality of the building sector while also capturing load diversity. Load diversity results in the peak demand of a building group is at least lower than the sum of individual coincidental peaks of individual buildings. This characteristic needs to be captured to evaluate the impact the aggregated demand on the centralized large-scale system. Integer constraints are required to ensure only one type of demand-side heat technology (µCHP or HP) is installed per individual building group. In other words, all buildings within a group install the same technology and operate it in an identical way. Hence, a binary variable $u_{htech}(b)$ for each heat technology *htech* (i.e. HP and µCHP) and building group *b* is introduced.

$$\sum_{htech} u_{htech}(b) = 1 \ \forall b \tag{2}$$

If a technology is chosen by the algorithm ($u_{htech}(b)=1$), then the capacity of the respective heat technology $C_{htech}(b)$ in Eq. 3 can take any value lower than a theoretical maximum chosen to be sufficiently large $C^{heat,max}$. If the binary value is set to 0, then $C_{htech}(b)$ is set to 0. This formulation (Eq. 3) is also referred to as big-M method in literature [19]

$$C_{htech}(b) \le u_{htech}(b) \cdot C^{heat,\max} \ \forall htech, \forall b \tag{3}$$

The integer constraints (Eq. 2-3) ensure that in the following constraints (Eq. 4-5), only an HP or µCHP within a single building group *b* can meet energy demand $D^{heat}(t,b)$ (Eq. 4) and peak heat capacity $P^{heat}(b)$ (Eq. 5).

$$\sum_{htech} E^{heat}_{htech}(t,b) \cdot = D^{heat}(t,b) \quad \forall t, \forall b \tag{4}$$

$$\sum_{htech} C^{heat}_{htech}(b) \cdot = P^{heat}(b) \quad \forall b \tag{5}$$

The operational capacity constraints for HPs and µCHPs differ (Eq. 6-7). For HPs, the energy $E^{heat}_{HP}(t,b)$ produced during the duration *TS* of one time step *t* needs to be lower than its installed capacity $C^{heat}_{HP}(b)$ (Eq. 6).

$$E^{heat}_{HP}(t,b) \le C^{heat}_{HP}(b) \cdot TS \quad \forall t, \forall b \tag{6}$$

Micro CHP operation is different to HP operation given that µCHPs can produce both heat and/or electricity. We assume µCHPs can operate in two different modes: dual-mode (heat and electricity) or electricity-only mode. In dual mode heat and electricity are coupled. In electricity-only mode, the µCHP can fully vent the generated heat into the atmosphere via a heat release valve and operate like a small-scale electricity generator. Therefore, electricity and heat are fully decoupled in electricity-only mode. The heat and electricity output schedules of µCHPs are determined through the least-cost formulation in Eq. 1. To model the electricity-only mode, a second auxiliary heat generation variable $E^{heat,vent}_{\mu CHP}$ is introduced that represents electricity generated while heat is vented into the environment. The energy generation variable $E^{heat}_{\mu CHP}$ depicts the dual mode where both electricity and heat are utilized. The sum of both energy generation variables needs to be lower than the capacity of the µCHP (Eq. 7)

$$\begin{aligned} & E^{heat}_{\mu CHP}(t,b) + E^{heat,vent}_{\mu CHP}(t,b) \\ & \quad \le C^{heat}_{\mu CHP}(b) \cdot TS \quad \forall t,\ \forall b,\ \forall \mu CHP \end{aligned} \tag{7}$$

Only $E^{heat}_{\mu CHP}$ can contribute to meeting heat demand (Eq. 4), but both $E^{heat}_{\mu CHP}$ and $E^{heat,vent}_{\mu CHP}$ do contribute in the electricity balance equation (Eq. 8) by conversion to electricity, along with supply-side electricity plants E^{elec}_{ptech}. Electricity generated from µCHPs can be derived from heat generation variables $E^{heat}_{\mu CHP}$ and $E^{heat,vent}_{\mu CHP}$ using the µCHP's thermal and electric efficiencies, $\eta^{therm}_{\mu CHP}$ and $\eta^{elec}_{\mu CHP}$. For each time step, electricity supply needs to be balanced with total electricity demand $D^{elec,total}(t)$, which is composed of electricity demand for non-heat applications $D^{elec,non\text{-}heat}(t)$ and electricity demand from heat pumps across all buildings, which can be expressed as HP heat generation $E^{heat}_{HP}(t,b)$ by division with the HP efficiency η_{HP}.

$$\begin{aligned} & \sum_{ptech} E^{elec}_{ptech}(t) + \sum_{b} N(b) \cdot \sum_{\mu CHP} \frac{\eta^{elec}_{\mu CHP}}{\eta^{therm}_{\mu CHP}} \left(\begin{aligned} & E^{heat}_{\mu CHP}(t,b) \\ & + E^{heat,vent}_{\mu CHP}(t,b) \end{aligned} \right) \\ & = \underbrace{\left(\begin{aligned} & D^{elec,non-heat}(t) \\ & + \sum_{b} N(b) \cdot \frac{1}{\eta_{HP}(T_{Amb}(t))} E^{heat}_{HP}(t,b) \end{aligned} \right)}_{D^{elec,total}(t)} \quad \forall t \end{aligned} \tag{8}$$

The dependency of the HP efficiency $\eta_{HP}(T_{Amb}(t))$ on ambient temperature $T_{Amb}(t)$ can be pre-computed using a linear relationship (Eq. 16, Section 0.

At all times, a capacity adequacy constraint ensures a system adequacy margin δ in relation to demand is respected, while considering the capacity credit *CCredit* of each generation technology *ptech* and µCHP technology (Eq. 9) [15].

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$$D^{elec,total}(t)\cdot\left(1+\delta\right)\le\sum_{ptech}CCredit_{ptech}\cdot C^{elec}_{ptech}$$
$$+\sum_{b}\sum_{\mu CHP}N(b)\cdot\frac{\eta^{elec}_{\mu CHP}}{\eta^{therm}_{\mu CHP}}\cdot CCredit_{\mu CHP}\cdot C^{heat}_{\mu CHP}(b)\quad\forall t \qquad (9)$$

µCHPs can also provide adequacy to the electricity system, so their capacity is included in the capacity margin constraint (Eq. 9). The full decoupled operation of µCHPs means that µCHPs can provide capacity during all times of the year, independently if heat demand is low or high.

Energy generated by each technology during *TS* one time step cannot exceed its capacity (Eq. 10). Energy generated by each technology must not be greater than the installed capacity multiplied by its availability *Av* to account for plant outages and maintenance (Eq. 11).

$$E^{elec}_{ptech}(t)\le C^{elec}_{ptech}\cdot TS\quad\forall t,\forall ptech \qquad (10)$$

$$\sum_{t=1}^{TS^{\max}}E^{elec}_{ptech}(t)\le C^{elec}_{ptech}\cdot Av_{PTech}\quad\forall ptech \qquad (11)$$

Total generation capacity is composed of existing and new built capacity (Eq. 12).

$$C^{elec}_{ptech}=C^{elec,existing}_{ptech}+C^{elec,new}_{ptech}\quad\forall ptech \qquad (12)$$

Electricity generated from VRE (e.g. wind) $E^{elec}_{VRE}(t)$ is limited by resource availability, defined by hourly capacity factors $CF_{VRE}(t)$ and the installed capacity C^{elec}_{VRE} (Eq. 13), and by operational system constraints (Eq. 14). To represent the operational system constraints, an approach used by the Irish grid operator is applied, which limits the system non-synchronous penetration (*SNSP*) (i.e. VRE energy generation and HVDC imports relative to demand)

$$E^{elec}_{VRE}(t)\le CF_{VRE}(t)\cdot C^{elec}_{VRE}\ \forall t,\forall VRE \qquad (13)$$

$$\sum_{VRE}E^{elec}_{VRE}(t)\le SNSP\cdot D^{elec,total}\quad\forall t \qquad (14)$$

A ramp-up and down constraint for base load plants is put in place to capture technical ramping limitations.

The capital payments are annualized using an annuity factor α which is defined by a discount rate *r* and the economic lifetime β of the investment:

$$\alpha=\frac{1-\left(1+r\right)^{-\beta}}{r} \qquad (15)$$

III. CASE STUDY

A detailed case study is presented in this section. It is used in Section IV, Results and Discussion, to illustrate the cost-optimal portfolios that result from the application of the methodology (Section II).

Ireland serves as case study given its limited interconnections to other systems and at the same time, a high penetration of wind energy (currently approximately 25 % electricity generation from wind and a target of 40% electricity generation from wind by 2020), which requires flexibility to balance supply and demand. The extensive lifetime of energy technology investments means that a significantly long-time horizon needs to be analyzed to capture changes in the generation mix. The study year is 2030 which is long enough for the capacity mix to evolve and make realistic assumptions around technology and policy development. As previously discussed, the variability of renewable energies and heat can impact the capacity portfolio [18]. An hourly representation *t* of all 8760 hours (TS^{max}) of the year is chosen to capture daily, weekly and seasonal variability.

Investments in supply technologies are discounted at 6%. Assumed lifetimes are summarized in Table I. For demand-side technologies (e.g. HP and µCHP), a discount rate of 10% is applied to represent the higher financing costs compared to large supply-side generation investors [20]. A lifetime of 15 years is assumed.

TABLE I
TECHNO-ECONOMIC CHARACTERISTICS OF POWER GENERATION PLANTS IN 2030

		Coal	CCGT	OCGT	Oil-CT	Wind
Unretired capacity 2030	MW	570	2270	200	0	2300
Efficiency	%	35	58	40	35	100
Investment cost	10^6€/MW	2.2	0.83	0.65	0.7	0.95
O&M fix	10^3€/MW/year	30	12	6.8	9.4	34
O&M var	€/ MWh	3	3.1	12.4	16.5	0
Carbon emission	kgCO$_2$/MWh	951	312	477	721	0
Capacity credit	%	99	99	99	99	15
Availability	h	7500	7500	7500	7500	/
Lifetime	years	30	25	25	25	20

Note: Wind (onshore wind), O&M fix (fixed O&M cost), O&M var (variable O&M cost), operational characteristics apply to new and existing plants.

The detailed elements of the case study include supply-side technologies (Section III.A), demand-side technologies (Section III.B), heat and electricity load profiles (Section III.C), fuel and carbon costs (Section III.D) and, finally, the MIP optimality settings (Section III.E).

A. Supply-side technologies

The existing electricity generation portfolio of the Irish energy system still operating by 2030 is expected to be mainly composed of wind (2300 MW), coal (570 MW), combine cycle gas (CCGT) (2270 MW) and open cycle gas (OCGT) (200 MW). Hydro is neglected here as its role is small (<2%). Capacity credits for generation technologies in the Irish system were sourced from Doherty [15]. The technical and economical parameters are collected from [21, 22] and summarized in Table I.

A transmission charge of 12 € per MWh, based on the current residential tariff in Ireland [23], is added to reflect electricity transportation cost. A capacity margin δ of 7% is assumed in Eq. 9. This is based on Doherty [15] and corresponds to a loss of load expectation of 8 hours per year, which is the reference adequacy standard in Ireland [30]. The SNSP level in Eq. 14 provides operational stability at high VRE penetrations and is set to 75%, which is the Irish SNSP target by 2020 [24].

B. Demand-side technologies

The different demand-side technologies include two µCHP technologies (Section III.B.1)) and HPs (Section 0).

1) Residential µCHP technologies

The µCHP technologies considered include fuels cells (FC) and internal combustion engines (ICE). These technologies are assumed to be fueled by natural gas. The capacity credit for non-decoupled operation was estimated between 62% and 92% for different market penetrations and technologies by Hawkes and Leach [25]. As described in Section II, µCHPs are modelled here such that their heat and electricity output can be fully decoupled. The capacity credit is therefore assumed to be high (95%), albeit lower than conventional generation (99%) to reflect the reality that the O&M service may be slightly inferior in residential setting (Table II).

The main difference between these µCHP technologies is their electrical efficiency and - related to that - thermal conversion efficiency. For a technology of energy input, FCs produce more electricity than ICEs (higher electricity efficiency) and consequently produce less heat (lower thermal efficiency) compared to ICEs. The technical and economical parameters of demand-side technologies FC and ICE are represented in Table II.

TABLE II
CAPITAL COST AND EFFICIENCY OF DEMAND-SIDE TECHNOLOGIES ANALYZED

	Capital cost	Capital cost	Therm. eff.	Elec. eff.	Capacity credit
	€/kW$_{th}$	€/kW$_{el}$	%	%	%
FC	2750 to 3500	3360 to 4280	50	45	95
ICE	1000 to 1500	3200 to 4800	70	25	95
HP	750 to1000	/	300	/	/

2) Heat pumps

Heat pumps only require electricity to drive a compressor that moves heat from a cold source (e.g. ambient air) to the warm sink (e.g. indoor air in buildings). The process efficiency is typically expressed as the coefficient of performance (COP). The COP decreases when the temperature difference between heat source and heat sink increases. This means that HPs are less performing at colder ambient temperatures, which is important to consider when determining the capacity of a HP. The HP dependence on ambient temperature is pre-computed using the following linear relationship with slope m based on performance data from [26].

$$\eta_{HP}(T_{Amb}(t)) = COP(T_{Amb}(t)) = m \cdot (T_{Amb}(t) - 280.15) + COP_{inp} \tag{16}$$

COP$_{inp}$ is defined by the COP measured at 280.15 K (7°C) as per EU performance regulations (EN 14511). The performance data for the HP are chosen for a supply temperature of 45°C which is used in low-temp radiators to provide space heating. HP investment cost are assumed to be between 750 and 1000 €/kW$_{th.}$

C. Demand load profile

1) Electricity load profile

Hourly electricity demand data is sourced from the Irish transmission system operator EirGrid [24]. The demand curve is inflated to a forecasted annual electricity demand of 34.4 TWh by 2030. The average daily demand resulting from this hourly data set is shown in Fig. 2.

2) Heat load profile

A quarter of Irish residential buildings (400 000 buildings) are represented as six aggregated building groups with index b. Buildings are very diverse in terms of their detailed characteristics but can be categorized based on their main physical properties. Detached houses represent roughly 50 % of the Irish building stock and are therefore the focus of this paper [27]. All 400 000 homes modelled here, are therefore assumed to be detached houses, which are divided into b groups. Heat demand in residential houses is composed of water heating and space heating. For an individual building, total annual heat demand is estimated to be 15000 MWh for space heating (94 kWh/year/m^2) and 3200 MWh for hot water by 2030, which reflect energy efficiency improvements.

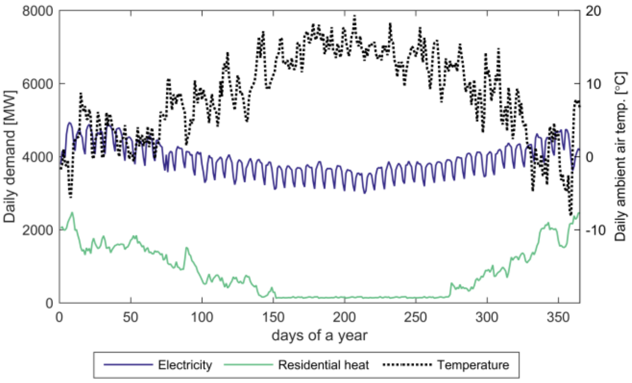

Fig. 2 Average daily electricity demand for Ireland in 2030, residential heat demand for 400 000 Irish homes and ambient air temperature.

The hourly aggregated heat profile is produced from metered data collected during a smart meter trial in Ireland covering 2000 households between 2009 and 2010 [28]. The data records household gas demand, so space and water heating were separated by assuming that the space heating season is limited between October and May [29] and that the monthly water profile is identical throughout the year. The use of metered data reflects the diversity of load and depicts a representative peak load that directly impacts generation capacity investments. It has been assumed that the data for these 2000 households can be scaled to represent larger sets of households. The resulting heat demand curve for 400 000 Irish households, shown for daily average in Fig. 2, highlights the strong seasonality of heat demand.

On an individual building level, heaters are sized to meet the heat peak demand which is assumed to be 13.7 kW for both water and space heating combined [30].

D. *Fuel and carbon prices*

To account for some of the future uncertainty in the variables, different fuel and carbon prices are analyzed. For natural gas, a low price of 8 €/GJ and high price of 12 €/GJ is assumed. The low natural gas price is roughly equal to the average natural gas price in 2015 in Europe. A coal price is set to 2.4 €/GJ and the oil price to 15 €/GJ [31]. To represent different carbon and environmental policies, a low price of 0 €/ton CO_2 and high price of 30 €/ton CO_2 are assumed. Table III summarizes the gas and carbon price scenarios.

TABLE III
GAS AND CARBON PRICE SCENARIOS

	Low carbon	High carbon
Low gas	8 €/GJ	8 € /GJ
	0 €/t CO_2	30 € /t CO_2
High gas	12 €/GJ	12 €/GJ
	0 € /t CO_2	30 € /t CO_2

E. *MIP optimality*

A MIP optimality gap – a relative termination tolerance criterion - of 0.01%. The optimization is implemented in GAMS (v. 25.5.4) and uses CPLEX as the solver. For all the input parameters presented in this case study, the solver finds a solution to the linear mixed integer problem in less than 30 minutes (on a computer with a 2.6 GHz processor and 16 GB RAM).

IV. RESULTS AND DISCUSSION

The methodology presented in Section II is applied to the case study introduced in Section III to determine cost-optimal portfolios that highlight the complementarities between supply and demand sides. The portfolios are made up of the unretired capacity, presented in Table I in the case study section (Section III), plus additions (including wind) and demand-side technologies.

The results are first presented for the electricity and heat system in isolation. The electricity system is modelled in isolation by setting heat demand to zero (Section IV.A); and, *vice versa*, by setting electricity demand for non-heat demand to zero the heat system is modelled in isolation (Section IV.B). The complementarity effect of the integrated system is then assessed for the integrated system (Section IV.C), which includes both electricity and heat demand. The comparison between isolated and integrated system reveals the complementarities between demand side and supply side technologies.

In the following, μCHP investment cost assumptions, in particular in several figures, are presented in terms of euros per thermal units ([€/kW_{th}]) in order to facilitate comparisons, even if thermal demand is zero (Section IV.A). A conversion to electricity-specific investment cost is available in Table II.

A. *Electricity-only Demand*

The results show that least-cost portfolio for 2030 with electricity-only demand (i.e. no heat demand) will have no demand-side investments (i.e. FC and ICE), whenever additional new supply-side thermal capacity (i.e. coal, CCGT and OCGT) can be built (see bar labelled 'supply allowed' in each subfigure in Fig. 3.). This reveals that demand-side investments for electricity-only demand are uneconomical compared to supply-side options. The least-cost portfolios for 'supply allowed' include a significant wind contribution, but its contribution is significantly higher if a higher carbon price of the order of 30€/tCO_2 is considered. To meet the adequacy constraint (Eq. 9), the total capacity increases with wind penetration due to the lower capacity credit of wind compared to thermal generators. Coal investment expands in most cases except when low gas and high carbon prices are applied, in which case no new coal generation is built.

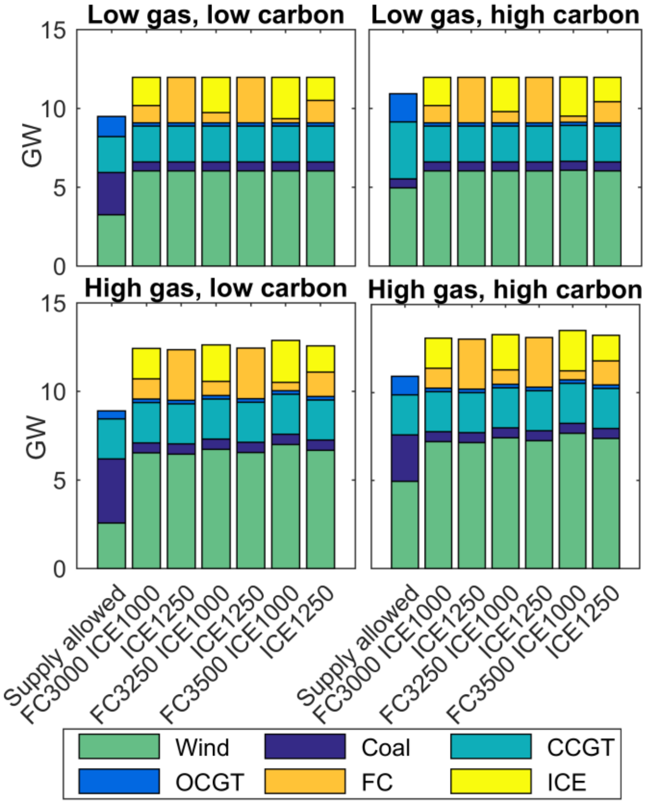

Fig. 3 Least-cost investment portfolios for different gas prices, carbon prices, FC and ICE investment costs for electricity-only demand. (Investment cost assumptions on x-axis in terms of euros per thermal units [€/kW_{th}]. The numeric values for gas and carbon prices are shown Table III.)

Future technology cost reductions or policy support for demand-side generation technologies or non-economic motivations, such as the desire to be self-sufficient, might however lead to deployment of demand-side technologies. To reflect this, new thermal supply-side capacity additions (coal, CCGT, OCGT) are not allowed i.e. constrained. The results are shown the Fig. 3 for different FC and ICE investment cost (in terms of €/kW_{th}). If thermal supply-side generation is constrained (all bars in Fig. 3, except the one labelled 'supply

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allowed') and limited to the thermal plants still in operation in 2030, the optimal capacity mix in 2030 will include demand-side technologies, namely FCs and ICEs. The portfolios where supply-side thermal generation is constrained also include a larger share of wind generation. Wind is providing low-cost energy, but requires the FCs and ICEs to support adequacy given the lower capacity credit of wind. Also, both FCs and ICEs, which have no ramping constraints over the hourly time resolution used, are providing flexibility in order to compensate for the wind variability. Wind contributed between 44% and 49% of the energy depending on the gas and carbon price. Micro CHPs contribute up to 37% in the low gas and carbon scenario, but in all other scenarios it is less than 7%, meaning that they mainly provide adequacy (i.e. reserve margin) to support wind generation.

For some µCHP investment costs, a mix of both demand-side technologies is used rather than a single technology (Fig. 3), which highlights the complementarity of the two technologies. FCs have lower operational costs due to their higher efficiency, but, for some cases, ICEs have lower investment costs (also in terms of €/kW$_{el}$). In order to meet a varying electricity demand, the optimal portfolio includes therefore a mix of both technologies: the more capital cost expensive FC (with lower operational cost) is operated more frequently, and the lower cost ICE is operated very sporadically (as a result of its high operational cost). This result is a mere translation of the known supply-side portfolio effect on the demand-side.

To summarize, the electricity-only system showed that µCHPs are not cost-competitive with supply-side generation. However, they can support wind integration by providing adequacy and flexibility, when the supply side is restricted. Just as for supply-side technologies, an optimal portfolio exists between the different µCHP technologies. Apart from providing electricity, µCHPs can also be used for heat provision.

B. Heat-only Demand

Electricity demand for non-heat demand is set to zero and only heat demand is considered to understand how the different heating technologies interact in a portfolio. Heat technologies include FCs and ICEs fueled by natural gas and HPs fueled by electricity either from the supply-side generators or from demand-side FCs and ICEs. For all the inputs considered, the least-cost portfolios do not include FCs due to their low thermal efficiency (45%), as opposed to ICEs (72.5%) and HPs (COP of 3).

For the six different building groups (as introduced previously in Section III.C.2.), only HPs are deployed in all building groups or a portfolio of HPs and ICEs is interacting across building groups (Fig. 4) for the wide range of gas, carbon and technology cost considered. Higher gas prices favor the use of HPs, but higher carbon prices make no notable difference. The relative cost between HPs and ICEs impacts the heater portfolio chosen: For high ICE (or low HP) cost, all building groups will use HPs. For low ICE (or high HP) costs, some buildings will install ICEs, while the majority of building groups (four out of six, or 67%) still maintain HPs. Interestingly the transition from all six building on HPs (100%) to four on HPs (67% on HPs) is very abrupt at one point when the difference between ICEs and HP investment cost is decreased by just 50 €/kW$_{th}$. However, if this cost difference grows further the number of building groups on HPs does not decrease below four (67%). This indicates a robust portfolio where HPs and ICEs complement each other well. In other words, the constant number of two ICEs (i.e. 33% or HP share is 67% in Fig. 4) in the optimal portfolio must get value from the fact that the remaining building groups use HPs or a full transition to an ICE-only portfolio would occur.

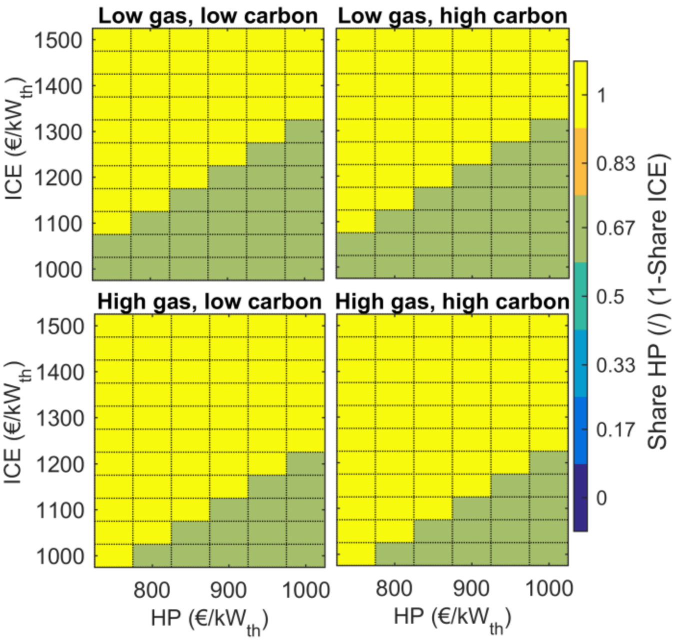

Fig. 4 Least-cost demand-side portfolios in six building groups *b* totaling 400k buildings as function of HP and ICE cost for heat-only demand. (The numeric values for gas and carbon prices are shown Table III.)

The underlying reason is the complementarity between ICE electricity production and HP electricity demand. An ICE is operated to meet a given heat demand and, at the same time, generates electricity as a by-product. This electricity generated by an ICE matches the electricity input required to fuel a HP in a different building group (Fig. 5), which reveals the complementarity between the different technologies across building groups. If ICE cost further decreases, the share of ICEs in the building groups does not change beyond the 33% (i.e. four HPs and two ICEs). This 2:1 ratio between the number of HP and ICE building groups is important to note. If installed in a 1:1 ratio, ICEs would produce an excess electricity outside of the space heating season (i.e. June to September, see right graph of Fig. 5). This excess is due to the higher COP of HPs during summer (when ambient temperatures are higher) and the resulting lower HP electricity demand, also revealing the importance of modelling the COP temperature dependence. A 2:1 ratio avoids any excess electricity during the summer. In reality and beyond the scope

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of this paper, there are cases when transmission systems are constrained and thus supply-side electricity generation is not fully realizable. In this case, a 1:1 ratio of HP and ICE building groups in districts connected through distribution networks could ensure adequate and reliable heat provision.

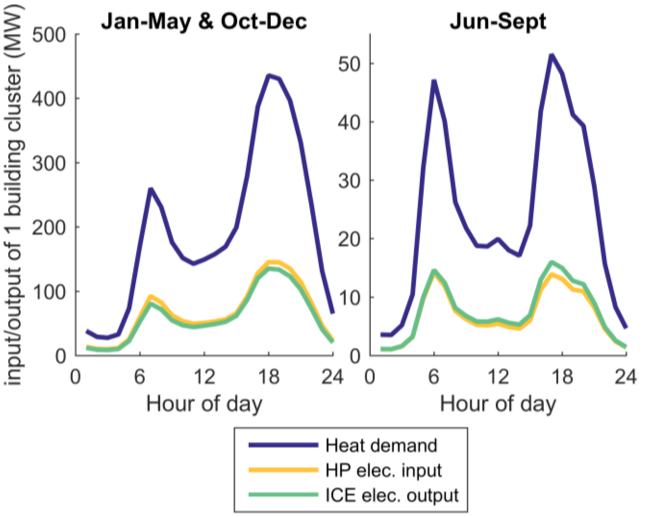

Fig. 5 Operational complementarity between HP and ICE in two different building groups *b* (one with HP and one with ICE) illustrated for an average day within the space heating season (left figure i.e. Jan-May & Oct-Dec) and outside the space heating season (right figure i.e. Jun-Sept).

To summarize, the value of ICEs is limited in a heat-only system: an increasing ICE penetration will create an excess of electricity that cannot be used, which would increase the cost of ICE heat production and degrade the value of the ICE. In an integrated system, however, this excess electricity can be utilized in the electricity system and increase the system value of ICEs.

C. Integrated Electricity-Heat System

In an integrated system, the µCHP units (i.e. FCs and ICEs) can contribute to meeting both energy demand services (i.e. electricity and heat) as well as electricity system services (i.e. adequacy and flexibility).

The optimal electricity portfolio in the integrated electricity-residential heat system includes a mix of supply and demand-side technologies that complement each other. Most interestingly, for certain ICE technology cost inputs, investments in demand-side ICE units are now preferred to supply-side generation expansion and prove to be optimal (Fig. 6). At high gas prices, ICEs though only contribute if their investment costs are the same as HPs. Wind capacity tends to be higher in cases where no ICEs are installed, in which case heat demand is entirely met by HPs.

The fact that demand-side ICE units are preferred for certain cost inputs is in stark contrast with Section IV.A, (i.e. optimal portfolio with electricity-only demand), where no µCHPs (FCs nor ICEs) were deployed unless the supply-side generation was constrained. The deployment of ICEs when both electricity and heat demand are considered highlights that the integrated energy system perspective improves the value proposition of demand-side technologies. ICE's role in the optimal portfolio is due to its system-wide value. From a heat generation perspective, ICEs are considerably less efficient (72.5%) than HPs with a coefficient of performance (COP) of 3. However, in the integrated system, ICEs also contribute to meeting electricity demand, including non-heat demand and HP demand, while also providing generating capacity and system flexibility (fast ramping capability).

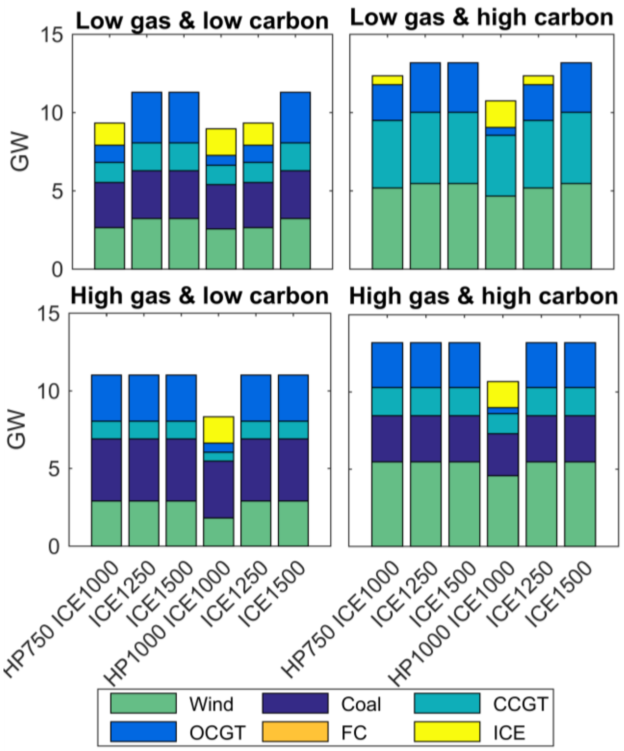

Fig. 6 Least-cost electricity investment portfolios for different gas prices, carbon prices, HP and ICE investment costs with both electricity and heat demand.(Investment cost assumptions on x-axis in terms of euros per thermal units [€/kW$_{th}$]. The numeric values for gas and carbon prices are shown Table III.)

The heat demand in the integrated system is met by both HPs and ICEs. FCs are not deployed due to their higher capital cost and lower thermal efficiency. For certain technology costs, an optimal portfolio with both HPs and ICEs exists, similar to the heat-only case (Section IV.B). However, compared to the heat-only case (Fig. 4), the cost difference between ICE and HP at which ICEs start to enter the portfolio is smaller, for all gas and carbon prices. This is due to the lower cost electricity available from supply-side generation for HPs, which makes them more cost-competitive. This is reflected graphically in Fig. 7 compared to Fig. 4 with the line above which only HPs are installed shifting along the x-axis to higher HP investment costs. However, if the investment cost of ICEs compared to HPs progressively decreases, then eventually all building groups shift to ICEs (i.e. HP share is 0% in Fig. 7). In the heat-only case (Fig. 4), this did not happen as ICEs needed HPs in the portfolio to increase their value by supplying excess electricity. In the integrated case, ICEs are displacing supply-side generation in delivering non-heat electricity demand. This means that when ICE investment cost progressively decreases (relative to HPs), more ICEs are installed as their value increases until eventually all buildings shift to ICEs.

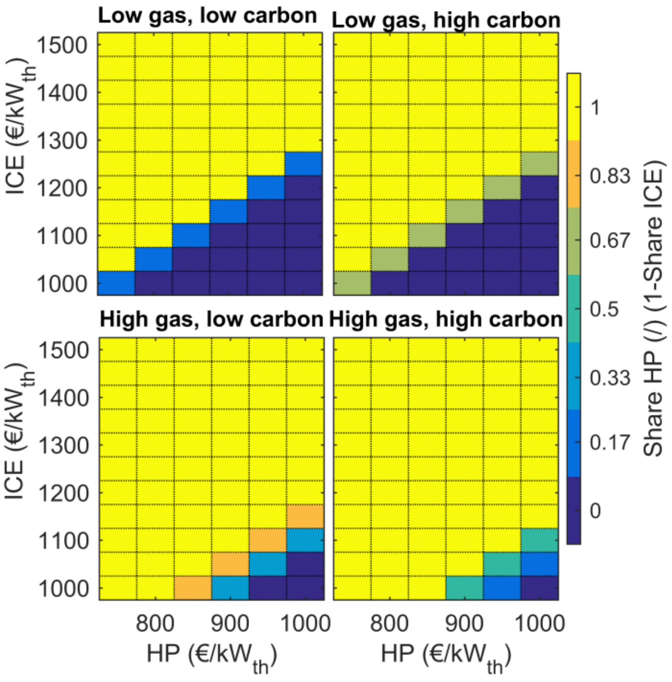

Fig. 7 Least-cost demand-side portfolio in building groups as function of HP and ICE cost for electricity and heat demand combined. (Investment cost assumptions on x-axis in terms of euros per thermal units [€/kW$_{th}$]. The numeric values for gas and carbon prices are shown Table III.)

D. Outcomes and Impact

The results from the integrated heat-electricity system (Section IV.C.) show that a multi-energy system, such as an ICE, can only reveal its full value when active in multiple markets simultaneously, as opposed to electricity-only (Section IV.A) and heat-only systems (Section IV.B) Additionally, only in the integrated energy system (Section IV.C) are demand-side ICEs preferred to supply-side generation, which demonstrates that integration unleashes the value proposition of demand-side technologies or, in general terms, of decentralization. Given the diversity of the demand-side in terms of users and the number of demand-side technologies beyond the ones analyzed here (e.g. solar PV and electric vehicles), the potential of designing markets that reflect the right investment signals is a complex task that needs to be further explored.

The methodology presented can be implemented by planners, investors and policymakers to assess the value of different supply and demand-side technologies in an integrated energy system. Different demand-side control mechanisms could also be assessed by modelling different levels of building aggregation and different demand-side decision-making processes other than the least-cost formulation used here.

V. CONCLUSION

The least-cost portfolio model proposed in this paper enabled the assessment of complementarities between technologies on the demand and supply sides in an integrated energy system. Electricity-heat integration was shown to improve the value proposition for energy system decentralization due to the complementarities. In an electricity-only system, demand-side technologies (i.e. ICEs) need to be mandated by not allowing supply-side expansion or requiring policy support. In heat-only systems, ICEs' cost-competitiveness for heat provision relies on selling excess electricity. In an integrated system though, ICEs' value proposition is leveraged more completely since they can sell excess electricity to the electricity market and can complement the supply side by providing adequacy and flexibility. Therefore, an integrated perspective can improve the value proposition for demand-side technologies. This also highlights the need on the demand-side for market design frameworks that reflect system investment requirements to aggregators and/or consumers.

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