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Flexibility and Grid Services from Distributed Multi-energy System

A thesis submitted to The University of Melbourne for the degree of

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by

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School of Electrical and Electronic Engineering

Abstract

The energy system is in the transition towards a low carbon future. Large-scale renewable energy resources (RES) and distributed energy resources (DER) are replacing conventional generators, which places great challenges on the traditional energy systems. The intermittent and uncontrollable nature of RES and lack of visibility of DER create more imbalances of supply and demand, which increase the demand for frequency control. On the other hand, the withdrawal of synchronous generators which are traditional grid services providers, further reduces system security. Additional flexibility and new grid services providers need to be sought in order to successfully integrate these emerging technologies while maintaining the reliability and security of the system.

Although the significance of consumer participation is seen as the “the heart of the transition”, the flexibility from consumers, DER, and other energy vectors and sectors, is yet untapped. This thesis aims to study the potential and possible ways of exploiting flexibility from such distributed multi-energy systems (DMES), so as to aid the integration of RES. In this context, a comprehensive, integrated techno-economic modeling framework is developed, in order to identify, quantify and optimize the flexibility from DMES and develop new relevant business cases. This includes, a high-resolution multi-energy demand model to understand the “building block” of the energy system analysis, a multi-markets, multi-services co-optimization model for optimal DMES operation, and a business case assessment model and an investment model for planning DMES under uncertainty to support

new business cases. The power of the abovementioned contributions is demonstrated through various realistic case studies.

Declaration

I declare that

1. This thesis comprises only original work towards the PhD, and no portion of the work referred to in this thesis has been submitted in support of an application for another degree or qualification of this or any other university or other institutes of learning.
2. Due acknowledgment has been made in the text to all other material used,
3. The thesis is less than 100,000 words in length, exclusive of tables, maps, bibliography, and appendices.

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Preface

The research outcomes of this thesis, which are published or submitted for publication are listed in this section. This thesis contains only the original work of the author and where appropriate, references have been made to the source when established techniques are used. Overall, six journal papers, eight conference papers, and one technical report, have been produced, and are listed below.

Journal articles

J1. A. Lesage-Landry, **H. Wang**, I. Shames, P. Mancarella, and J. A. Taylor, "Online Convex Optimization of Multi-energy Building-to-grid Ancillary Services", *IEEE Transactions on Control Systems Technology*, DOI: 10.1109/TCST.2019.2944328.

- The first author involves in modeling, analyzing the results, and writing the paper. The second author involves in modeling, writing, and proofreading. The third author, fourth author, and fifth author involve in supervision and proofreading.

J2. **H. Wang**, S. Riaz, and P. Mancarella, "Integrated Techno-economic Modeling, Flexibility Analysis, and Business Case Assessment of an Urban Virtual Power Plant with Multi-market Co-optimization", *Applied Energy*, vol. 259, DOI: 10.1016/j.apenergy.2019.114142.

- The first author involves in modeling, analyzing the results, and writing the paper. The second author involves in modeling, writing, and proofreading. The third author involves in supervision and proofreading.

J3. J. Naughton, **H. Wang**, S. Riaz, M. Cantoni, and P. Mancarella, "Optimization of Multi-Energy Virtual Power Plants for Providing Multiple Market and Local Network Services", *Electric Power Systems Research*, to be published.

- The first author involves in modeling, analyzing the results, and writing the paper. The second author and third author involve in modeling, writing, and proofreading. The fourth author and fifth author involve in supervision and proofreading.

J4. R. R. Appino, **H. Wang**, JÁ González Ordiano, T. Faulwasser, R. Mikut, V. Hagenmeyer, P. Mancarella, "Energy-based stochastic MPC for integrated electricity-hydrogen VPP in real-time market", *Electric Power Systems Research*, to be published.

- The first author involves in modeling, analyzing the results, and writing the paper. The second author, third author involve in modeling, writing, and proofreading. The fourth author, fifth author, sixth author, and seventh author involve in supervision and proofreading.

J5. J. Naughton, **H. Wang**, M. Cantoni, P. Mancarella, "Value Stack Co-optimization of Market, Security, and Network Services for Virtual Power Plants Operating Under Uncertainty", *IEEE Transactions on Power Systems*, under review.

- The first author involves in modeling, analyzing the results, and writing the paper. The second author involves in writing and proofreading. The third author and fourth author involve in supervision and proofreading.

J6. H. Wang, I. Shames, P. Mancarella, "Optimal Operation and Investment for an Integrated Renewables-Hydrogen Energy Hub with Multi-market Co-optimization", *IEEE Transactions on Smart Grid*, under review.

- The first author involves in modeling, analyzing the results, and writing the paper. The second author and third author involve in supervision and proofreading.

Conference papers

C1. H. Wang, A. Saint-pierre, and P. Mancarella, "System Level Cost and Environmental Performance of Integrated Energy Systems: An Assessment of Low-Carbon Scenarios for the UK," in *2015 IEEE Eindhoven PowerTech*, Eindhoven, 2015, pp. 1-6.

- The first author involves in modeling, analyzing the results, and writing the paper. The second author involves in writing and proofreading. The third author involves in supervision and proofreading.

C2. H. Wang and P. Mancarella, "Towards Sustainable Urban Energy Systems: High Resolution Modelling of Electricity and Heat Demand Profiles," in *2016 IEEE International Conference on Power System Technology (POWERCON)*, Wollongong, NSW, 2016, pp. 1-6.

- The first author involves in modeling, analyzing the results, and writing the paper. The second author involves in supervision and proofreading.

C3. H. Wang, N. Good, P. Mancarella, and K. Lintern, "PV-Battery Community Energy Systems: Economic, Energy Independence and Network Deferral Analysis," in *2017 14th International Conference on the European Energy Market (EEM)*, Dresden, 2017, pp. 1-5.

- The first author involves in modeling, analyzing the results, and writing the paper. The second author involves in modeling, writing, and proofreading. The third author and fourth author involve in supervision and proofreading.

C4. H. Wang, N. Good, and P. Mancarella, "Modelling and Valuing Multi-Energy Flexibility from Community Energy Systems," in *2017 Australasian Universities Power Engineering Conference (AUPEC)*, Melbourne, VIC, 2017, pp. 1-6 (**Best paper award, 1st**)

- The first author involves in modeling, analyzing the results, and writing the paper. The second author involves in modeling, writing, and proofreading. The third author involves in supervision and proofreading.

C5. H. Wang, N. Good, and P. Mancarella, "Economic Analysis of Multi-service Provision from PV and Battery Based Community Energy Systems," in *2017 IEEE Innovative Smart Grid Technologies - Asia (ISGT-Asia)*, Auckland, 2017, pp. 1-6.

- The first author involves in modeling, analyzing the results, and writing the paper. The second author involves in modeling, writing, and proofreading. The third author involves in supervision and proofreading.

C6. H. Wang, N. Good, E. A. Martínez Ceseña, and P. Mancarella, "Co-optimization of a Multi-Energy Microgrid Considering Multiple Services," in *2018 Power Systems Computation Conference (PSCC)*, Dublin, Ireland, 2018, pp. 1-6.

- The first author involves in modeling, analyzing the results, and writing the paper. The second author and third author involve in modeling, writing, and proofreading. The fourth author involves in supervision and proofreading.

C7. S. Riaz, J. Naughton, H. Wang, P. Mancarella, "Flexibility and grid services from integrated electricity-hydrogen distributed energy systems," *2020 CIGRE Paris 2020*, in press.

- The first author involves in modeling, analyzing the results, and writing the paper. The second author and third author involve in modeling, writing, and proofreading. The fourth author involves in supervision and proofreading.

C8. Q. Gao, M. Demoulin, H. Wang, S. Riaz, P. Mancarella, "Flexibility characterization from thermal inertia of buildings at city level: A bottom-up approach," *Universities Power Engineering Conference (UPEC) 2020*, under review.

- The first author and second author involve in modeling, analyzing the results, and writing the paper. The third author involves in writing, and proofreading. The fourth author involves in supervision, writing, and proofreading. The fifth author involves in supervision and proofreading.

Reports

R1. P. Mancarella, S. Puschel, L. Zhang, **H. Wang**, M. Brear, T. Jones, M. Jeppesen, R. Batterham, R. Evans, and I. Mareels, *“Power System Security Assessment of the Future National Electricity Market,”* a report by the Melbourne Energy Institute at the University of Melbourne in support of *The Independence Review into the Future Security of the National Electricity Market* (the “Finkel Review”).

Dedicated with love and gratitude to my parents

Xiaohua Li and Xiaoming Wang,

and my grandparents

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Your unyielding love, support, and encouragement,

make me who I am today.

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Acronyms

AEMO	Australian Energy Market Operator
ASX	Australian Security Exchange
BoM	Bureau of Meteorology
CAES	Compressed Air Energy Storage
CCGT	Combined Cycle Gas Turbine
CEEP	Critical Exceed Electricity Production
CHP	Combined Heat and Power Plant
COP	Coefficient of Performance
CVPP	Commercial Virtual Power Plant
DA	Day-ahead
DER	Distributed Energy Resources
DG	Distributed Generation
DMES	Distributed Multi-energy System
DNSP	Distribution Network Service Provider
DR	Demand Response
DPP	Discounted Payback Period
EV	Electric Vehicles
FB	Fishermans Bend
FCAS	Frequency Control Ancillary Services
FFR	Fast Frequency Response
G2V	Grid to Vehicle
GCP	Grid Connection Point
GIS	Geographical Information System
GST	Good and Services Tax
HVAC	Heating, Ventilation, and Air Conditioning

ICES	Integrated Community Energy System
ICT	Information and Communication Technology
LWR	Least-worst Regret
MES	Multi-energy Systems
MILP	Mixed-linear Linear Programming
NEM	National Electricity Market
NER	National Electricity Rules
NLAS	Network Loading Ancillary Services
NSCAS	Network Support and Control Ancillary Service
NSP	Network Service Provider
NSW	New South Wales
NPV	Net Present Value
OCGT	Open Cycle Gas Turbine
OTC	Over the Counter
P2G	Power-to-gas
PFR	Primary Frequency Response
QLD	Queensland
RES	Renewable Energy Sources
RERT	Reliability and Emergency Reserve Trader
RET	Renewable Energy Target
RoCoF	Rate-of-change-of-frequency
RT	Real-time
SA	South Australia
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SGA	Small Generation Aggregator
SRAS	System Restart Ancillary Services

STPIS	Service Target Performance Incentive Scheme
TAS	Tasmania
TOSAS	Transient and Oscillatory Stability Ancillary Services
TVPP	Technical Virtual Power Plant
UoM	University of Melbourne
V2G	Vehicle to Grid
VCAS	Voltage Control Ancillary Services
VEET	Victorian Energy Efficiency Target
VIC	Victoria

Notations

Chapter 3

Index/Set

$c, \mathbf{C}$	Customer sector, set of customer sectors
$d, \mathbf{D}$	Day, set of days of the year
$p, \mathbf{P}$	Postcode, set of postcode areas
$r, \mathbf{R}$	Region, set of regions
$t, \mathbf{T}$	Half-hour settlement, set of half-hour settlements t

Parameter

$AE_{c,p}$	Postcode level annual electricity demand of customer sector cs for postcode area pcd (kWh _e)
$AE_{c,r}$	Regional annual electricity demand of customer sector cs for region reg (kWh _e)
$AH_{c,p}$	Postcode level annual heat demand of customer sector cs for postcode area pcd (kWh _{th})
$AH_{c,r}$	Regional annual heat demand of customer sector cs for region reg (kWh _{th})
$DE_{d,c,r}$	Regional daily electricity demand of customer sector cs for region reg (kWh _e)
$DH_{d,c,r}$	Regional daily heat demand of customer sector cs for region reg (kWh _{th})
$E_{t,c}$	Household level intraday electricity demand of customer sector cs (kW _e)
$E_{t,c,p}$	Postcode level intraday electricity demand of customer sector cs for postcode area pcd (kW _e)
$H_{t,c}$	Household level intraday heat demand of customer sector cs (kW _{th})
$H_{t,c,p}$	Postcode level intraday heat demand of customer sector cs for postcode area pcd (kW _{th})

$N_{c,p}$ Postcode level number of customers of customer sector c for postcode area p (integer)

Variables

$de_{d,c,p}$ Postcode level daily electricity demand of customer sector cs for postcode area pcd (kWh_{th})

$dh_{d,c,p}$ Postcode level daily heat demand of customer sector cs for postcode area pcd (kWh_{th})

$e_{t,c,p}$ Half-hourly electricity demand of customer sector cs for postcode area pcd at time t (kW_e)

$h_{t,c,p}$ Half-hourly heat demand of customer sector cs for postcode area pcd at time t (kW_{th})

Chapter 4

Index/Set

$a, \mathbf{A}$ Heating and cooling appliance, set of heating and cooling appliances

$b, \mathbf{B}$ BESS, set of BESS

$f, \mathbf{F}$ Fuel, set of fuels

$g, \mathbf{G}$ Generator, set of generators

$h, \mathbf{H}$ Electrolyzers, set of electrolyzers

$l, \mathbf{L}$ Building, set of buildings

$r, \mathbf{R}$ RES, set of RES

$v, \mathbf{Y}$ Reliability price bucket, set of reliability price buckets

$t, \mathbf{T}$ Settlement period, set of settlement periods

$th, \mathbf{TH}$ TES, set of TES

$\chi, \mathbf{X}$ FCAS product, set of FCAS products

Parameters

Δt Length of time step (h)

$\overline{\Delta T}_l^{set}$	Max up variation from set temperature for building l ($^{\circ}\text{C}$)
$\underline{\Delta T}_l^{set}$	Max down variation from set temperature for building l ($^{\circ}\text{C}$)
C_l	Building thermal capacitance of building l ($\text{kWh}_{\text{th}}/^{\circ}\text{C}$)
C_{th}^{tes}	TES thermal capacitance of TES th ($\text{kWh}_{\text{th}}/^{\circ}\text{C}$)
$H_{t,l}^{met}$	Metabolic heat gain of building l at time t (kW_{th})
$H_{t,l}^{sol}$	Solar heat gain of building l at time t (kW_{th})
M	Arbitrarily large number
$O_{t,l}$	Building occupancy level of building l at time t (integer)
$\overline{P}^-$	GCP maximum import power (kW_e)
$\overline{P}^+$	GCP maximum export power (kW_e)
$\underline{P}_b^{bes-}$	BESS minimum charge power (kW_e)
$\overline{P}_b^{bes-}$	BESS maximum charge power of BESS b (kW_e)
$\underline{P}_b^{bes+}$	BESS minimum discharge power of BESS b (kW_e)
$\overline{P}_b^{bes+}$	BESS maximum discharge power of BESS b (kW_e)
$\underline{P}_g^{gen}$	Generator minimum output power of generator g (kW_e)
$\overline{P}_g^{gen}$	Generator maximum output power of generator g (kW_e)
$\underline{P}_h^{hp}$	Electrolyzer minimum output power of electrolyzer h (kW_e)
$\overline{P}_h^{hp}$	Electrolyzer maximum output power of electrolyzer h (kW_e)
$P_{t,r}^{res}$	RES maximum power output of RES r at time t (kW_e)
P_t^{FFR}	FFR obligation at time t (kW_e)
$\underline{P}_{l,a}^{app}$	Heating and cooling appliance minimum cooling output power of heating and cooling appliance a at building l (kW_e)
$\overline{P}_{l,a}^{app}$	Heating and cooling appliance maximum cooling output power of heating and cooling appliance a at building l (kW_e)
$\underline{P}_{l,a}^{app}$	Heating and cooling appliance minimum heating output power of heating and cooling appliance a at building l (kW_e)
$\overline{P}_{l,a}^{app}$	Heating and cooling appliance maximum heating output power of heating and cooling appliance a at building l (kW_e)

R_l	Building thermal resistance of building l ($^{\circ}\text{C}/\text{kWh}_{\text{th}}$)
R_{th}^{tes}	TES thermal resistance of TES th ($^{\circ}\text{C}/\text{kWh}_{\text{th}}$)
T_t^{out}	Outdoor temperature at time t ($^{\circ}\text{C}$)
T_l^{set}	Building set temperature of building l ($^{\circ}\text{C}$)
$\underline{T}_{th}^{tes}$	TES minimum temperature of TES th ($^{\circ}\text{C}$)
$\overline{T}_{th}^{tes}$	TES maximum temperature of TES th ($^{\circ}\text{C}$)
$\underline{X}_b^{bes}$	BESS minimum energy level of BESS b (kWh_e)
$\overline{X}_b^{bes}$	BESS maximum energy level of BESS b (kWh_e)
$\underline{X}_f^{fuel}$	Fuel storage minimum energy level of fuel f (kWh_e)
$\overline{X}_f^{fuel}$	Fuel storage maximum energy level of fuel f (kWh_e)
W	Winter binary indicator (binary)
$\Phi_{h,f}^{hp}$	Electrolyzer fuel output indicator of electrolyzer h and fuel type f (binary)
$\Phi_{g,f}^{gen}$	Generator fuel input indicator generator g and fuel type f (binary)
$e_{\chi,a}^{app}$	Heating and cooling appliance FCAS participation indicator of heating and cooling appliance a for FCAS product χ (binary)
$e_{\chi,b}^{bes}$	FCAS participation indicator of BESS b for FCAS product χ (binary)
$e_{\chi,g}^{gen}$	FCAS participation indicator of generator g for FCAS product χ (binary)
$e_{\chi,h}^{hp}$	FCAS participation indicator of electrolyzer h for FCAS product χ (binary)
$e_{\chi,r}^{res}$	FCAS participation indicator of RES r for FCAS product χ (binary)
$call^{DR}$	Demand response call length (h)
$call_{\chi}^{FCAS}$	FCAS call length for FCAS product χ (h)
λ^{cap}	Cap upfront payment ($\$/\text{kW}_e/\text{h}$)
λ^{DR}	DR upfront payment ($\$/\text{kW}_e$)
λ_t^{elec-}	GCP electricity import prices at time t ($\$/\text{kWh}_e$)
λ_t^{elec+}	GCP electricity export prices at time t ($\$/\text{kWh}_e$)

$\lambda_{t,f}^{fuel-}$	GCP fuel import prices of fuel f at time t (\$/kWh _{fuel})
$\lambda_{t,f}^{fuel+}$	GCP fuel export prices of fuel f at time t (\$/kWh _{fuel})
$\lambda_{t,\chi}^l$	Lower FCAS prices of FCAS product χ at time t (\$/kWe/h)
$\lambda_{t,\chi}^r$	Raise FCAS prices of FCAS product χ at time t (\$/kWe/h)
$\lambda_{t,v}^{rel}$	Reliability services prices for price bucket v at time t (\$/kWe/h)
λ^{peak}	Peak demand charge (\$/kWe/month)
γ_g^{gen}	Generator operational costs of generator g (\$/kWh _e)
γ_g^{SD}	Generator shut-down costs of generator g (\$/kWh _e)
γ_g^{SU}	Generator start-up costs of generator g (\$/kWh _e)
ω_t^{cap}	Cap contract call window at time t (binary)
ω_t^{DR}	Demand response window at time t (binary)
ρ_b^{bes}	BESS round trip efficiency of BESS b
ρ^{blind}	Blind exclusion efficiency
ρ_g^{gen}	Generator efficiency of generator g
ρ_h^{hp}	Electrolyzer efficiency of electrolyzer h
ρ^{DR}	DR rolling schedule factor
ρc_a^{app}	Heating and cooling appliance cooling efficiency of heating and cooling appliance a
ρh_a^{app}	Heating and cooling appliance heating efficiency of heating and cooling appliance a

Variables

$e_{t,f}^-$	Fuel import at GCP level of fuel f at time t (kWh _{fuel})
$e_{t,f}^+$	Fuel export at GCP level of fuel f at time t (kWh _{fuel})
$h_{t,l}^{sc}$	Space cooling demand for building l at time t (kWh _{th})
$h_{t,l}^{dhw}$	Domestic hot water demand of building l at time t (kWh _{th})
$h_{t,l}^{sh}$	Space heating demand for building l at time t (kWh _{th})
$h_{t,th}^{in}$	TES heat energy input of TES th at time t (kWh _{th})

$h_{t,th}^{out}$	TES heat energy output of TES th at time t (kWh _{th})
p_t^-	Electricity import at GCP level at time t (kW _e)
p_t^+	Electricity export at GCP level at time t (kW _e)
$\bar{p}^{GCP}$	Maximum import power at GCP (kW _e)
p^{cap}	Cap contract commitment (kW _e)
p^{DR}	Aggregated demand response commitment (kW _e)
$p_a^{DR,app}$	Heating and cooling appliance demand response commitment of heating and cooling appliance a (kW _e)
$p_b^{DR,bes}$	BESS demand response commitment of BESS b (kW _e)
$p_g^{DR,gen}$	Generator demand response commitment of generator g (kW _e)
p_t^{FFR}	Aggregated FFR commitment at time t (kW _e)
$p_{t,b}^{FFR,bes}$	BESS FFR commitment of BESS b at time t (kW _e)
$p_{t,h}^{FFR,hp}$	Electrolyzer FFR commitment of electrolyzer h at time t (kW _e)
$p_{t,r}^{FFR,res}$	RES FFR commitment of RES r at time t (kW _e)
$p_{t,b}^{bes-}$	BESS charge power of BESS b at time t (kW _e)
$p_{t,b}^{bes+}$	BESS discharge power of BESS b at time t (kW _e)
$p_{t,r}^{curt}$	RES curtailment of RES r at time t (kW _e)
$p_{t,g}^{gen}$	Generator output power of generator g at time t (kW _e)
$p_{t,h}^{hp}$	Electrolyzer operating power of electrolyzer h at time t (kW _e)
$p_{t,\chi}^l$	Aggregated lower FCAS commitment for FCAS product χ at time t (kW _e /h)
$p_{t,\chi,a}^{l,app}$	Heating and cooling appliance lower FCAS commitment of heating and cooling appliance a for FCAS product χ at time t (kW _e /h)
$p_{t,\chi,b}^{l,bes}$	BESS lower FCAS commitment of BESS b for FCAS product χ at time t (kW _e /h)
$p_{t,\chi,g}^{l,gen}$	Generator lower FCAS commitment of generator g for FCAS product χ at time t (kW _e /h)
$p_{t,\chi,h}^{l,hp}$	Electrolyzer lower FCAS commitment of electrolyzer h for FCAS product χ at time t (kW _e /h)

$p_{t,\chi,r}^{l,res}$	RES lower FCAS commitment of RES r for FCAS product χ at time t (kW _e /h)
$p_{t,\chi}^r$	Aggregated raise FCAS commitment for FCAS product χ at time t (kW _e /h)
$p_{t,\chi,a}^{r,app}$	Heating and cooling appliance raise FCAS commitment of heating and cooling appliance a for FCAS product χ at time t (kW _e /h)
$p_{t,\chi,b}^{r,bes}$	BESS raise FCAS commitment of BESS b for FCAS product χ at time t (kW _e /h)
$p_{t,\chi,g}^{r,gen}$	Generator raise FCAS commitment of generator g for FCAS product χ at time t (kW _e /h)
$p_{t,\chi,h}^{r,hp}$	Electrolyzer raise FCAS commitment of electrolyzer h for FCAS product χ at time t (kW _e /h)
$p_{t,\chi,r}^{r,res}$	RES raise FCAS commitment of RES r for FCAS product χ at time t (kW _e /h)
$p_{t,r}^{res}$	RES output power of RES r at time t (kW _e)
p_t^{rel}	Aggregated reliability services commitment at time t (kW _e /h)
$p_t^{rel,D}$	Reliability services commitment dummy variable (kW _e /h)
$p_{t,v}^{rel}$	Reliability services commitment for price bucket v at time t (kW _e /h)
$p_{t,b}^{rel,bes}$	Reliability services commitment of BESS b at time t (kW _e /h)
$p_{t,g}^{rel,gen}$	Reliability services commitment of generator g at time t (kW _e /h)
$p_{t,r}^{rel,res}$	Reliability services commitment of RES r at time t (kW _e /h)
$pc_{t,l,a}^{app}$	Heating and cooling appliance cooling power of heating and cooling appliance a at building l at time t (kW _e)
$ph_{t,l,a}^{app}$	Heating and cooling appliance heating power of heating and cooling appliance a at building l at time t (kW _e)
$u_{t,l,a}^{app}$	Heating and cooling appliance heating/cooling binary indicator of heating and cooling appliance a at building l at time t (binary)
$u_{t,b}^{bes}$	BESS charge/discharge binary indicator of BESS b at time t (binary)
u_t^{elec}	GCP electricity import/export binary indicator at time t (binary)
$u_{t,g}^{on}$	Generator on/off binary indicator of generator g at time t (binary)
$u_{t,h}^{on}$	Electrolyzer on/off binary indicator of electrolyzer h at time t (binary)

u_t^{rel}	Reliability services binary indicator at time t
$u_{t,v}^{rel}$	Reliability services price buckets binary indicator of price bucket v at time t
$u_{t,g}^{SD}$	Generator shut-down binary indicator of generator g at time t (binary)
$u_{t,h}^{SD}$	Electrolyzer shut-down binary indicator of electrolyzer h at time t (binary)
$u_{t,g}^{SU}$	Generator start-up binary indicator of generator g at time t (binary)
$u_{t,h}^{SU}$	Electrolyzer start-up binary indicator of electrolyzer h at time t (binary)
$v_{t,l}^{met}$	Degree of ventilation of metabolic heat gains of building l at time t
$v_{t,l}^{sol}$	Degree of ventilation of solar heat gains of building l at time t
$x_{t,b}^{bes}$	BESS energy level of BESS b at time t (kWh _e)
$x_{t,f}^{fuel}$	Fuel storage energy level of fuel type f at time t (kWh _e)
$x_{t,th}^{loss}$	TES energy loss to the environment of TES th at time t (kWh _{th})
$x_{t,th}^{tes}$	TES energy level of TES th at time t (kWh _{th})
$\tau_{t,l}$	Building temperature of building l at time t (°C)

Chapter 5

Index/Set

$i, \mathbf{I}$	Candidate technology, set of candidate technologies
$s, \mathbf{S}$	Scenario, set of scenarios
$t, \mathbf{T}$	Settlement period, set of settlement periods
$y, \mathbf{Y}$	Project year, set of project years
$\chi, \mathbf{X}$	FCAS product, set of FCAS products

Parameter

Δt	Length of time step (h)
$c_{i,s}$	Investment cost of technology i for scenario s (\$/kW)

N^{DR}	Total DR call length (h)
r	Discount rate
θ_i	Maximum number of units that can be installed over a year of technology i (integer)
$\bar{\theta}_i$	Maximum number of units that can be installed over the project life of technology i (integer)
λ_s^{cap}	Cap upfront payment under scenario s (\$/kW _e /h)
$\bar{\lambda}_s^{cap}$	Cap strike price under scenario s (\$/kW _e /h)
λ_s^{DR}	DR upfront payment under scenario s (\$/kW _e)
$\bar{\lambda}_s^{DR}$	DR call payment under scenario s (\$/kW _e)
$\lambda_{t,s}^{elec-}$	GCP electricity import prices at time t for scenario s (\$/kWh _e)
$\lambda_{t,s}^{elec+}$	GCP electricity export prices at time t for scenario s (\$/kWh _e)
$\lambda_{t,f,s}^{fuel-}$	GCP fuel import prices of fuel f at time t for scenario s (\$/kWh _{fuel})
$\lambda_{t,f,s}^{fuel+}$	GCP fuel export prices of fuel f at time t for scenario s (\$/kWh _{fuel})
$\lambda_{t,\chi,s}^l$	Lower FCAS prices of FCAS product χ at time t for scenario s (\$/kW _e /h)
$\lambda_{t,\chi,s}^r$	Raise FCAS prices of FCAS product χ at time t for scenario s (\$/kW _e /h)
λ_s^{peak}	Peak demand charge under scenario s (\$/kW _e /month)
$\gamma_{i,s}^{fixed}$	Generator fixed operational costs of generator g for scenario s (\$/kW/year)
γ_{agg}^{fixed}	Fixed operational costs of aggregation (\$/year)
γ_{agg}^{var}	Variable operational costs of aggregation (\$/kW/year)
$\gamma_{g,s}^{gen}$	Generator variable operational costs of generator g for scenario s (\$/kWh _e)
$\gamma_{g,s}^{SD}$	Generator shut-down costs of generator g for scenario s (\$/kWh _e)
$\gamma_{g,s}^{SU}$	Generator start-up costs of generator g for scenario s (\$/kWh _e)

Variable

c_s^{agg}	Aggregation controlled technology capacity for scenario s (kW)
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$e_{t,f,s}^-$	Fuel import of fuel f at time t for scenario s (kWh _{fuel})
$e_{t,f,s}^+$	Fuel export of fuel f at time t for scenario s (kWh _{fuel})
$p_{t,s}^-$	Electricity import at time t for scenario s (kW _e)
$p_{t,s}^+$	Electricity export at time t for scenario s (kW _e)
p_s^{cap}	Cap contract commitment for scenario s (kW _e)
p_s^{DR}	Demand response commitment for scenario s (kW _e)
$p_{t,\chi,s}^l$	Lower FCAS commitment for FCAS product χ at time t for scenario s (kW _e /h)
$p_{t,\chi,s}^r$	Raise FCAS commitment for FCAS product χ at time t for scenario s (kW _e /h)
$u_{y,i,s}$	Number of units of technology i at year y for scenario s (integer)

Function

c_s	Operational cost at year y for scenario s (\$/year)
$npv_{y,s}$	Net present value at year y for scenario s (\$)
p_s	Annual operational profits at year y for scenario s (\$/year)
r_s	Operational revenue at year y for scenario s (\$/year)

Chapter I. Introduction

1.1 Background and motivations

The energy systems are experiencing unprecedented transformations. To fight against climate change and fossil fuel depletion, the system operators are shifting their focuses from the “*energy dilemma*”, i.e., balancing the energy cost and reliability, to the “*energy quadrilemma*” [1], [2], i.e., balancing the energy cost, reliability, sustainability which is related to carbon emissions and natural resources usages, as well as social acceptability. This essentially leads to changes in the way how electricity is produced, delivered, and consumed. The traditional power system, which is a one-way system that heavily relies on conventional power plants, is shifting towards a low carbon, integrated energy system, as Figure I-1 shows.

At the supply side, the grid-scale renewable energy resources (RES), such as wind power and solar photovoltaics (PV), are replacing traditional synchronous generators worldwide. The global RES capacity has reached 2,350 GW in 2018 [3], accounting for one-third of the world's total generation capacity. The RES capacity has doubled in the past decade, compared with a total capacity of 1,136 GW in 2009, and is predicted to keep growing by one fifth in the next five years. The RES expansions are mainly based on the weather-dependent renewable sources, noticeably as variable RES. Due to their intermittent and non-synchronous nature, the integration of RES has placed great challenges on the traditional power system operation. The generation of RES is highly dependent on the primary resources, which may fluctuate in the order of seconds. This variability and uncertainty of

the RES require greater and faster reserves in the power system in order to maintain the balance between demand and supply. Meanwhile, the increasing penetration of RES and the withdrawal of synchronous generators further reduce the system inertia, leading to faster frequency dynamics. The primary frequency response (PFR) that is traditionally provided by conventional generators might not be able to be sufficient for these faster frequency fluctuations.

Concurrently, there is also rapidly increasing penetration of distributed energy resources (DER) at the demand side, e.g., rooftop solar photovoltaic (PV), combined heat and power (CHP) units, battery energy storage systems (BESS), and thermal energy storage (TES), motivated by increased economic feasibility [4], [5]. For example, the cumulative household PV capacity reached 7,982 MW in Australia by the end of 2018, with more than 2 million installations [6]. Moreover, there are also increasingly large loads from electrifications of other energy sectors including heating, cooling, and transportation, through the use of technologies such as electric heat pumps (EHP), electric heaters, and electric vehicles (EV). This is occurring at multiple network levels, but it is particularly notable at a neighborhood or district level, given the low base for such technologies. This dramatic uptake of DER has brought opportunities to improve energy system efficiency by avoiding transmission and distribution losses and reducing the network footprint. It also opens up the possibility of economic benefits for consumers, who, as DER owners, can become “prosumers”, and suppliers of flexibility services to various energy system actors. However, the integration of DER is also challenging the traditional operation of power systems. As the distributed RES, such as rooftop PV, tends to cluster geographically, the excessive generation from DER might lead to greater distribution network strain [7], [8], while network reinforcement might be

needed to accommodate surplus generation without any flexibility options. Moreover, currently, most of the DER that are installed “behind the meter” are not visible to the system operator [7]. This lack of visibility places a direct impact on the traditional power system operation, as it reduces the system operator’s ability of load forecasting which increases the demand for frequency control in order to maintain system frequency. The invisibility of the DER also affects the power system operation under extreme operation conditions, which further reduces the reliability and security of the system.

From an economic perspective, the integration of RES and DER also results in a more volatile electricity market. The increasing power output from RES and DER will potentially result in decreases in the capacity factors for conventional power plants. As a result, the conventional generators may increase their marginal prices or shut down the plants so as to stay profitable [9]. Capacity support from small and expensive generators may be needed for system operators during peak demand periods, contributing to more volatile electricity prices.

All the aforementioned developments and changes add challenges and complexities in the traditional power system operation, which call for additional flexibility in the power system, from generation, transmission and distribution systems, storage, and potentially flexible demand-side resources. Meanwhile, the increasing interactions between various energy sectors, such as electricity, heating and cooling, gas, and transportation, also calls the need for developing so-called multi-energy systems (MES). In this context, the following sections elaborate on the concept of MES, flexibility, the sources for flexibility, and grid services.

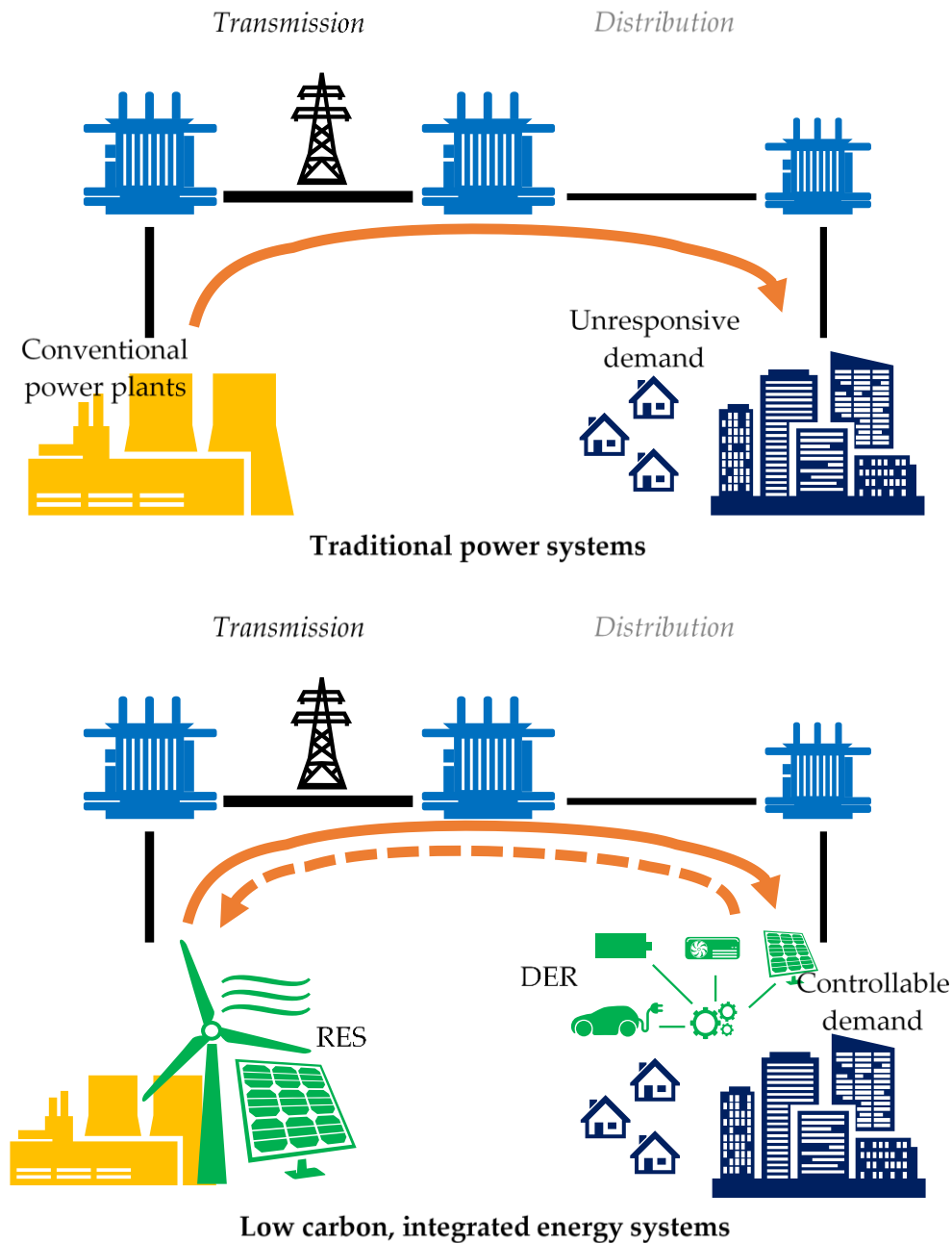


Figure I-1. Power systems transition, from a conventional power system towards a low carbon, integrated energy systems

1.1.1 Multi-energy systems

In the traditional paradigms of energy system planning and operation, the energy sectors such as electricity, heating, cooling, transportations, and fuels, are planned and operated separately with minor interactions. In recent years, increas-

ing interactions and interdependencies between different sectors have been experienced, especially at the district level, due to the development of distributed multi-generation and electrification of multiple energy demands including heating, cooling, and transportation. This started with the integration of co-generation technologies, such as combined heat and power plant (CHP) units, which generate electricity and useful heat concurrently from a certain fuel [10], [11]. As an extension of cogeneration, trigeneration systems such as combined heat, cooling and power (CHCP) units, are designed to provide electricity, heating and cooling simultaneously [11]–[13], which often combine traditional CHP units with cooling production equipment, which can cover multi-energy demand of the consumers. As efficient and economic alternatives of conventional gas boilers to provide space heating demand, EHP systems have further increased the interdependencies between electricity, heating and cooling sectors [11], [14]. Furthermore, the development of power-to-gas (P2G) technologies, and the rising number of electric vehicle (EV) as well as hydrogen-based transport, also increase the interactions between electricity, transportation, and fuels [15], [16].

In response to these undergoing changes in the energy system transformation, and to improve the efficiency, flexibility, reliability, and affordability of the energy system, the concept of *multi-energy systems* (MES), which is also noted as *integrated energy systems*, are developed [14], [17], [18]. An MES enables optimal operation and planning across all interdependent energy sectors, such as electricity, heating, cooling, fuel, and transportation, at different scales. For example, at a building level, within a district, at a city, a region or a country level.

It is well recognized in the literature that coupling multiple energy sectors can bring numerous benefits to the energy systems from technical, economic and environmental points of view, from both operational and planning stages. By coupling CHP and EHP with thermal energy storage (TES), significant flexibility can be offered by shifting electricity consumption and generation [19], [20]. Similarly, when enabling building temperature flexibility, i.e., allowing the building temperature to deviate from the set temperature for a short amount of time, heating, ventilation, and air conditioning (HVAC) systems are able to contribute to the grid flexibility [21]. This can be done by shifting the electricity consumption through pre-cooling or pre-heating of the building and store the thermal energy in the building fabric [22], or by reducing and increasing the electricity consumption for a short period of time. Furthermore, Capuder and Mancarella discuss the techno-economic and environmental benefits of different distributed multi-generation options, which show that replacing conventional gas boilers with a combination of CHP and EHP coupled with TES to provide heating demand brings significant cost savings from both operational and investment perspectives, while reduces the primary energy consumption [20]. From an environmental point of view, the integrated option of CHP and EHP with the support of TES also results in the reduction of carbon emissions [20]. However, the ability of them contributing to the decarbonization of the heat sector is highly dependent on the power system decarbonization. Moreover, P2G technologies, which are developed to absorb the excess generation of RES and store the energy in the form of hydrogen or synthetic natural gas, are also proven to be a substitute to the electrical network reinforcement in the network area which is struggling to accommodate excessive RES generation [23].

1.1.2 Flexibility¹

Operational flexibility seen in the power system is the technical ability of the power system to respond to the changes in demand and supply [24]. The operational flexibility is required in order to eliminate the imbalance between supply and demand, which may be caused by the disturbance from load and generation, and any kind of outages that creates imbalances in power flows [25]. The operational flexibility in the power system includes both “upward flexibility”, which refers to the increase of power generation or decrease in the demand, and “downward flexibility”, which refers to the decrease in power generation or increase in the demand.

Various sources are available to provide power system operational flexibility [24], [26], [27], as illustrated in Figure I-2. The operational flexibility can be provided by changing the output of the dispatchable generation such as conventional power plants. The operational flexibility can also be obtained from RES, either through curtailment or through operating the RES at a curtail mode. Moreover, flexible demand-side resources can also contribute to power system operational flexibility, for instance, by shifting, curtailing, or substituting the flexible demand from domestic, commercial and industrial sectors, and altering the operation of distributed generation and distributed storages. Operational flexibility can also be provided by stationary energy storage, such as pumped hydro storage, compressed air energy storage (CAES), and BESS. Furthermore, the flexibility can be obtained from importing electricity from or exporting electricity to other grid

¹ This thesis mainly focuses on active power flexibility. However, the reactive power flexibility also plays a certain role in the power system operation which can be provided by a wide range of technologies such as conventional generator, RES, BESS, P2G, EV, and DER.

zones through interconnectors. Additional flexibility can be attained from other energy sectors, for example, the transportation sector through the EV, or gas sector using P2G technologies.

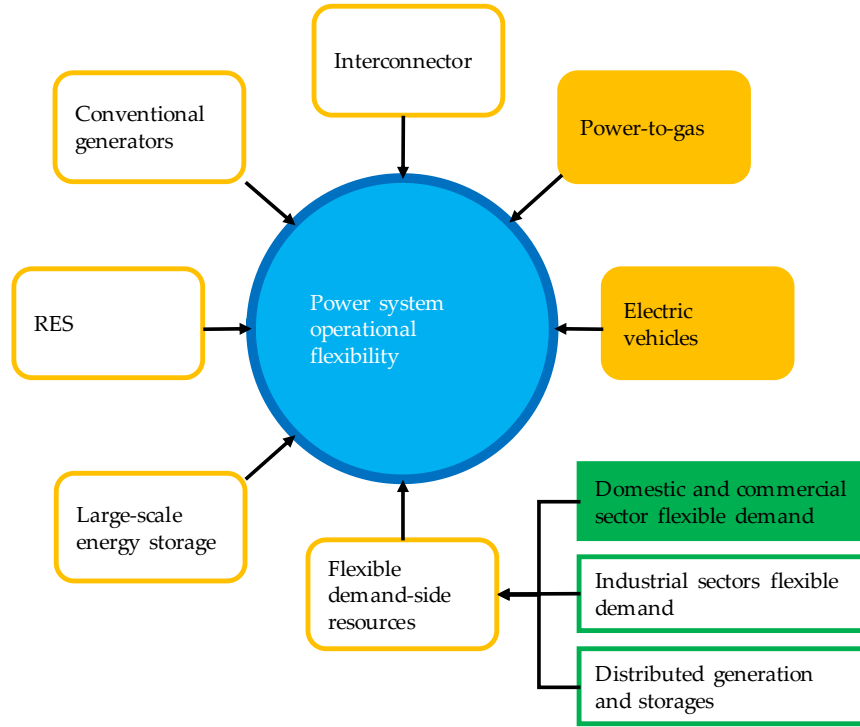


Figure I-2. Available sources of operational flexibility

Operational flexibility is often associated with a cost deviation, which can be expressed as *economic flexibility*. The economic flexibility indicates the ability of a party to vary its behavior within a given cost, given a certain incentive. In another word, economic flexibility can be seen as the willingness of a party to deviate from its normal operating points, from economic points of view. Operational flexibility is a requirement for economic flexibility. However, having operational flexibility does not guarantee economic flexibility.

The operational flexibility is normally traded in two forms, i.e., as *energy products* in the electricity market, or as *reserve products* in ancillary service markets [25].

Based on [25], the operational flexibility resources can be classified into *potential*

flexibility resources, actual flexibility resources, flexibility reserves, and market-available flexibility reserves. The *potential flexibility resources* refer to the whole feasible operation region that the resources can achieve, without considering the controllability and observability (or predictability) of the resources, while the *actual flexibility resources* are the potential flexibility resources that can be used when considering the controllability and observability of the resources. The *flexibility reserves* are the actual flexibility resources that can be used economically, which depends on the resources' economic flexibility. Furthermore, the *market-available flexibility reserves* are the flexibility reserves that are gained from electricity and/or ancillary services markets, as the ability of flexibility reserves participating in markets may be limited due to the structure of ancillary service products. This showcases the importance to evaluate both technical flexibility, which plays a vital role influencing the potential flexibility resources and actual flexibility resources, and economic flexibility when assessing the flexible resources, which determine the flexibility reserves and market-available flexibility reserves.

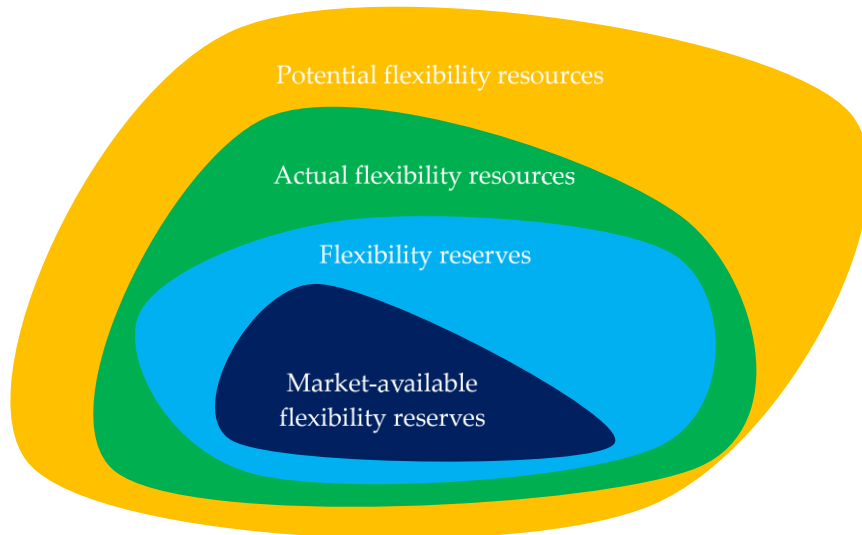


Figure I-3. Classification of operational flexibility [25]

1.1.3 Sources of flexibility

Operational flexibility has various key characteristics, such as the *quantity of flexibility*, the *speed of flexibility*, the *duration of flexibility*, and the *cost of flexibility* [28]. The quantity of flexibility represents the peak amount of flexibility that can be provided by the technologies. The speed of flexibility is how quickly the technologies can respond, which includes how fast can the technologies increase or decrease without start-up and shut-down, and how long it takes to start-up and shut-down. The duration of flexibility determines how long can the provision of flexibility be sustained. The cost of flexibility includes the operational costs for providing flexibility, as well as the capital cost for investing the technologies, which helps to determine the economic flexibility. Understanding those technical and economic characteristics is essential to determine the suitable technologies to meet the structural flexibility requirements and responding to certain contingency events. This section compares different flexibility resources, listing their advantages and disadvantages.

1.1.3.1 Conventional power plants

In traditional power systems, conventional power plants have the responsibility to provide operational flexibility. The widely used conventional power plants include coal-fired power plants, combined cycle gas turbines (CCGT)², and open cycle gas turbines (OCGT)³. The quantity of the flexibility of a conventional power plant is determined by its operating range, which is limited by its installed power

² A CCGT consists of both a gas turbine which is powered by natural gas, and a steam turbine which is powered by the exhaust heat from gas turbine [30], [191].

³ A OCGT powers the turbine by using the expansion of the combustion gases [30], [191], which is often used to meet the peak-load demand.

capacity, as well as its minimum load, i.e., the minimum power required for a generator to operate reliably, which is often represented as the percentage of its capacity. The minimum loads of coal-fired power plant, CCGT, and OCGT vary within a range of 40% to 50% [29], [30], resulting in operating ranges of 50% to 60% of their capacities, which can be used to provide flexibility when the generators are online. Ramping up and ramping down rates (i.e., defined as the percentage of installed capacity per minute), together with start-up and shut-down times of the conventional power plants determine the speed of flexibility. The coal-fired power plants are considered as the least flexible generation units among the three, due to their long periods of time required for start-up and slow ramping rate. It takes 3 hours to 6 hours for a coal-fired power plant to start up, and a ramping up/down rate of 2%/minute [29], [30]. The CCGT are more flexible compared to the coal-fired power plants and are suitable for load-following operation, which take about 1.5 hours to 2 hours to start, with common ramping rates of 4%/minute [29], [30]. The OCGT are considered as fast start units which take less than 0.1 hours to start, with ramping rates around 12%/minute [30]. The duration of the flexibility of conventional power plants is dependent on the fuel storage capacity, which is often not restricted. The provision of flexibility often influences the overall efficiency of all the conventional power plants, which leads to the increase of their operational costs such as fuel costs and maintenance costs. Moreover, the costs are also highly dependent on fuel costs. In general, the base-load power plants, such as coal-fired power plants, are often inflexible but have low operational costs. Load following power plants, such as CCGT units, which are more flexible and can adapt daily variation of demand and supply, are more expensive. The peaking units, which

are the most flexible units such as OCGT units, often have the highest operational costs than the other two.

It can be concluded that the advantage of conventional power plants in providing flexibility is that they often do not have limitations on the duration of flexibility. However, the major limitation of conventional power plants from the technical perspective is the speed of flexibility (except for OCGT units), which may not be able to provide flexibility within a short period of time in order to meet today's requirement. Moreover, there are also economic barriers underlaying the provision of flexibility from conventional power plants, such as increasing variable costs as a result of flexible operation.

1.1.3.2 Renewable energy resources

RES can contribute to operational flexibility through active power control⁴, i.e., altering the RES output power. By curtailing the output power, the RES can provide downward flexibility, while by operating below the maximum possible power output the RES can provide upward flexibility [31].

Most of the RES installed have the technical capability to change its power output over the course of milliseconds or seconds [31]. Nevertheless, the amount of flexibility and duration of flexibility are highly uncertain due to the stochastic nature of their resources. From an economic perspective, the marginal cost of RES is neglectable, thus the active power control of RES can be seen as a cost-effective way to provide flexibility to the system. However, curtailing the RES power output or operating them below its maximum power output might reduce the potential

⁴ RES can also contribute to reactive power flexibility through reactive power control.

economic benefits from participating in energy markets, thus reduce the willingness of RES to provide flexibility.

1.1.3.3 Interconnection

The quantity of the flexibility available from interconnection is specific to the capacity of the interconnector, the flexibility available at the other grid zones. The capacity of the interconnector is a function of ambient conditions, such as temperature, wind speed and direction, and solar insolation. In general, there is no technical time restriction on the speed of flexibility from interconnection, which can be considered to be able to provide flexibility at a very fast speed. The cost of interconnectors is driven by their capital costs, which is mainly dependent on the distance of the interconnector. The high capital costs of infrastructures also arise the economic barriers of importing flexibility.

1.1.3.4 Energy storage

The energy storage refers to the technologies that are able to charge, hold and discharge energy, which have great potential to attribute to system operational flexibility, providing varying grid support services such as load shifting, short term balancing services, as well as fast act instantaneous services [32]. Common storage technologies including pumped hydro storage, CAES, and BESS. The pumped hydro storage store energy in the form of the gravitational potential energy of water. By using electricity to pump water from lower reservoirs to higher reservoirs, i.e., operating at the charge mode, the pumped hydro storages can provide downward flexibility to the grid, while upward flexibility can be provided by releasing the water flowing back to the turbine to generate electricity, i.e., operating at the discharge mode. The CAES store energy in the form of compressed air,

which can be heated and expanded in the gas turbine to produce electricity [33]. The BESS refer to the electrochemical energy storage systems, which can store electricity in the form of chemical potentials (i.e., charge mode) and convert them back to electricity when needed (i.e., discharge mode) [30], [34]. BESS can provide upward flexibility by increasing its discharge power output or decreasing its charge power output while providing downward flexibility by increasing its charge power output or decreasing its discharge power output.

The amount of flexibility from energy storage is determined by its charge/discharge power capacity. Moreover, the energy storages are also able to provide flexibility instantaneously, due to their fast ramping rates and short start up time. For the pumped hydro storages and CAES, it takes around 0.1 hours to start [29], [30]. Moreover, the pumped hydro storages can reach a ramping up/down rate of 40%/minute [29], [30]. The CAES have a typical ramping rate of 20% in the charging mode, while a typical ramping rate of 10% every 3 seconds when in discharge mode [29], [30]. Furthermore, BESS can provide very fast response, in the course of milliseconds [35]. The duration of flexibility for energy storage is highly constrained by their energy capacities. For pumped hydro storage, the energy capacity may also vary seasonally. In general, energy storages have a comparably low operational and maintenance costs, which makes them economically viable to provide flexibility. However, the capital costs are high which creates economic barriers of integrating energy storage in the energy system.

The energy storages have great potential to provide operational flexibility with a very fast ramping rate. This is the major advantage of energy storage especially in a low inertia system, where the fast speed responses are desired to maintain the

reliability. However, the major limitation of the energy storage to provide flexibility is their energy capacities, which place constraints on the duration of the flexibility, thus they cannot sustain the services for an extended period of time. From an economic perspective, investment costs are the main barriers to invest in new energy storage technologies, which requires the development of new business models to make them profitable.

1.1.3.5 Electric vehicles

The EV can contribute operational flexibility to the system in two operation mode, i.e., grid to vehicle (G2V), during when the EV demand can be seen as a flexible demand which can be shifted, and vehicle to grid (V2G), where the EV batteries can be discharged to feed electricity to the grid. The EV are able to provide both upward flexibility and downward flexibility. When operating in G2V mode, EV can provide upward flexibility by decreasing charge power, while providing downward flexibility by increasing charge power. When operating in V2G mode, EV are able to provide upward flexibility by increasing discharge power while contributing to downward flexibility by decreasing discharge power.

The quantity of flexibility depends on the capacity of EV that is connected to the grid, while the duration of flexibility often depends on the energy content of the EV battery, and the users charging behavior. For example, the EV are often connected to the grid during the night-time which enables them to provide flexibility for a long period of time. Thus, the electrification of transport can greatly increase the potential of shifting electricity demand, especially within-day electricity profiles [26]. The quantity and duration of EV are highly dependent on the transportation demand which is inherently uncertain.

1.1.3.6 Power-to-gas

P2G refer to the energy storage technologies that use electricity as input fuel to generate gas in the form of methane and/or hydrogen [16], which can be used as fuel for transportation or conventional generators. P2G have great advantages in improving the environmental performances of energy systems in terms of utilizing excess electricity production generated from intermittent energy conversion technologies in high RES scenarios [36] [37]. By modifying the input power, the P2G are able to provide both upward flexibility (by decreasing power input) and downward flexibility (by increasing power input). Due to the low COP (e.g., 30% to 45%), P2G are often only operated to absorb excessive RES generation. The quantity of flexibility that can be provided by P2G depends on the capacity of the technologies. From an economic point of view, the quantity of flexibility from P2G also depends on the excess RES generation at a specific time. The reaction time of P2G can vary from seconds to minutes. The duration of flexibility depends on the fuel storage capacity and the fuel demand from transportation sectors and the conventional power plants. However, the main obstacle in implementing P2G is the high operational costs in particularly in terms of transporting and storing hydrogen [37].

1.1.3.7 Flexible demand-side resources

The consumers' participation is seen as "the heart of the transition" [38], which is a valuable source in providing operational flexibility to the power system. However, the potential flexibility from demand-side resources is yet untapped. The flexible demand-side resources include distributed generation, distributed storages, and flexible multi-energy demand.

Distributed generation, such as rooftop PV, CHP, and distributed energy storage, such as BESS and TES, have substantial potential to provide operational flexibility to the system. PV, CHP, and BESS can provide operational flexibility directly by changing their operations, while TES can contribute to operational flexibility when coupled with other technologies such as CHP, EHP, or electric boilers. The speed of the flexibility from distributed generation and distributed storages are considerably high. More specifically, a small-scale CHP can often start within 5 minutes with a typical ramping rate of 5%/minute to 20%/minute [30], while the inverter-based technologies such as PV and BESS can change their operation in the course of milliseconds. The duration of the flexibility is technology dependent. For example, the flexibility from PV is highly uncertain and is determined by the solar isolations, while for BESS the duration of flexibility is constrained by the energy content. The CHP can provide operational flexibility for a longer period of time as it is determined by the fuel storage which has less restriction than the BESS and PV. The costs of flexibility from PV and BESS can be considered minor due to their low operational costs, while for the CHP it is highly dependent on the fuel prices. Although distributed generation and storages have great values when providing operational flexibility, they are too small to participate in the markets or provide grid services alone, which calls for the need of aggregations.

The flexible demand may be divided into several groups, 1) the electricity demand that can be shifted, 2) the electricity demand that can be curtailed, and 3) the electricity demand that can be substituted by other types of fuel. More specifically, shifting electricity consumption can be done by shifting industrial process time, shifting heating and cooling time by utilizing the thermal storage in the buildings, or shifting base load consumption such as dishwashers and washing machines.

Moreover, some demand can be curtailed if needed, in the trade of economic benefits. For example, by changing the set temperature of the building for a limit of time, electricity demand can be reduced with minor impacts on the users' thermal comfort [39]. Furthermore, electricity consumption for heating can sometimes be substituted by using the technologies that require other types of fuels. For example, instead of using EHP for space heating, gas boiler and CHP can be used.

In recent years, there are growing new large loads from the electrifications of space heating and cooling demand, such as electric heater, and EHP, from the domestic sector. Domestic buildings have great potential to provide operational flexibility to the grid, by shifting their electricity demand, and by substituting the electricity consumption with other fuels such as natural gas. The quantity of flexibility from the domestic sector flexible load is time-varying, depends on the heating and cooling demand from the residential buildings. The speed of flexibility from flexible loads in the domestic sector can be seen as very quick, i.e., 100%/min. The operational cost of shifting heating and cooling load is minor, which makes them economical resources to provide flexibility. However, barriers from the social aspect, including the consumers' concerns of privacy and security, as well as the willingness of consumers to change their demand, further limit the potential flexibility that can be contributed from domestic sector flexible loads. Moreover, the potential from flexible demand is also uncertain, which requires a comprehensive understanding and modeling of the demand.

The profile of industrial demand varies among different industries, depending on the specific industrial processes. Some industrial loads have the potential to

provide operational flexibility, by shifting part of their loads by changing the processing time. The industrial sector can provide upward flexibility by lowering its demand while providing downward flexibility by increasing its demand. The duration of flexibility can vary from one hour to a day, depending on the industrial process and the demand for the products. The operational cost and investment cost of implementing demand response using industrial load can be very low.

1.1.4 Grid services

Electricity is a passive commodity which is difficult and expensive to store. Due to this characteristic of electricity, the system operator needs to dispatch generation in order to match the demand in a real-time manner, so as to deliver electricity to consumers while maintaining the grid operated in a reliable and secure manner. Electricity demand naturally fluctuates over the course of hours and days, while unexpected changes can often happen in real-time. In addition, unpredicted outages of power plants, non-scheduled outages of transmission lines and distribution lines, and the variabilities of RES, create more challenges and complexities of power system operation. In order to “keep the light on”, grid services, also known as “ancillary services”, are introduced as the services and functions to aid the grid operator to operate the grid within its defined technical limitations, such as frequency control and voltage support, and maintain the reliability and security of the grid. In general, the ancillary services operate on a time scale from sub-second to one day. The timeline of the grid operating and planning functions in the context of the Australian National Electricity Market (NEM) based on [40] is illustrated in Figure I-4, in which the ancillary services are shown on the left side of Figure I-4.

The ancillary services have three main functions, that is, providing flexibility to balance supply and demand, maintaining the frequency close to the normal operating frequency, and providing voltage support. Traditionally, the ancillary services are exclusively provided by conventional power plants. The withdrawal of conventional power plants calls for the needs of new services providers to provide both active power and reactive power flexibility. Furthermore, the increasing penetration of inverter-based technologies and the decreasing percentage of the synchronous generators leads to a higher rate-of-change-of-frequency (RoCoF), that is, the rate of changes in frequency after a contingency event. This increases the requirement on the speed of the flexibility, while more fast-act technologies are desired. Ancillary services may include a wide range of services, such as frequency control ancillary services, voltage control ancillary services, system restart ancillary services, and demand response. With the increasing penetration of the DER and the concept of aggregation, new forms of ancillary services specifically featuring distributed multi-energy systems (DMES) may be developed. For example, the distribution network reliability services [41]–[43] is a potential service that can be provided by the grid-connected microgrid. By using its DER, the microgrid is able to provide reliability service to its internal consumers during the contingency, while helping with restoring the neighborhood customers after contingency. However, different from the existing forms of ancillary services, the distribution network reliability services are not very well defined.

As discussed before, various resources are suitable for providing flexibility with fast response. Particularly, the demand-side resources, which are seen as untapped flexibility, can provide ancillary services with affordable costs. Exploiting flexibility from demand-side resources requires understanding the nature of the

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demand and overcoming the social barriers. Other technologies such as large-scale storages, P2G, and RES are also suitable candidates as grid service providers. Business cases need to be developed for such technologies to overcome economic barriers.

Besides using ancillary services as a means to maintain the reliability of the grid in the short term, it is also essential to maintain grid reliability over the long run. The planning reserve, which also referred to as resource adequacy, ensures that the excess power generation is available in the future if it is needed [44]. The planning reserves are illustrated on the right side of Figure I-4. This thesis mainly focuses on short term ancillary services.

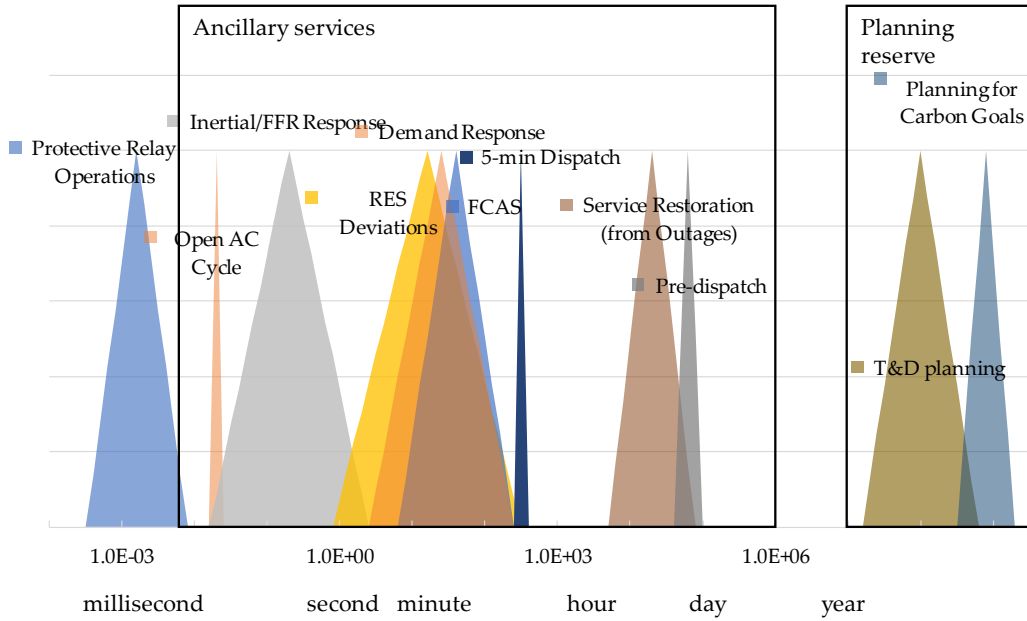


Figure I-4. Time scale of grid operation and planning functions in the context of Australia

1.2 Opportunities and challenges

In order to successfully integrate emerging low-carbon technologies while maintaining the reliability and security of the system, new grid service providers,

as well as greater and faster flexibility are required. As introduced in the previous section, great opportunities are seen from the potential flexibility embedded in multiple energy sectors and vectors, for example, demand-side resources and P2G. From a technical perspective, those technologies often have the capability of providing significant flexibility at a very fast speed. From an economic perspective, they also have the potential to provide flexibility at reasonable costs. However, deploying the flexibility from multi-energy sectors and vectors, especially from demand-side resources, has not been fully investigated in the literature, which is complex and leads to several challenges.

First of all, there is a lack of understanding of when and where the flexibility can be extracted from the demand-side resources at different levels, which can provide a holistic view of the potential flexibility from both temporal and spatial perspectives. The flexibility potential from demand-side resources is highly dependent on the consumers' behavior, which often leads to uncertainties in multi-energy demand, such as space heating and cooling demand, and hot water demand. This requires, firstly, detailed modeling of buildings and occupants' behavior so as to accurately represents different building types and users' behavior; and secondly, appropriate aggregation methodologies using widely available information.

Moreover, providing flexibility from multiple sectors and vectors creates complexity as it increases the coupling of different energy sectors and markets. For instance, substituting electrical heating with gas boiler increases the gas demand while decreases the electricity demand. The development of P2G further tightens the interactions between the electricity sector and the gas sector. Moreover, more

complexities are added in the operation of the technologies, due to the introduction of energy storages such as BESS, TES, and building thermal storage. Different from traditional load following operation strategy, the operation of technologies is now more flexible. On the one hand, this flexible operation could potentially contribute to the operational flexibility of the system, and on the other hand, it may also exacerbate the problems that are already faced in the systems. For instance, without proper controlling or coordinating, the prosumers may choose concentrated electricity export electricity at the same time, which may place greater strain on distribution networks. These growing complexities require proper technical models that are able to optimize multiple energy sectors and vectors as a whole and considers a wide range of technologies.

Thirdly, the economic value of the flexibility from multi-energy sectors and vectors is not yet clear, as a result, the quantity of the flexibility that can be extracted is often underestimated. Participating in various markets and provide grid services leads to economic benefits, which may boost the economic flexibility of consumers of aggregators, so as to incentivize them to provide flexibility using available resources. However, when considering multiple market participation and grid service provision, conflicts or synergies may arise. This, firstly, calls for a comprehensive review of existing and potential markets and services and investigations of the commercial agreements and economic value of the markets and services. Moreover, a powerful tool that is able to truly capture the value of flexibility from multi-energy sectors considering all potential revenue streams from market participation and service provision, is also desired.

Lastly, there are needs for developing business models for technologies such as DER and P2G. The business cases should be assessed when the value of flexibility is fully exploited. As discussed before, this requires detailed modeling from both technical and economic perspectives. It is also important to develop investment strategies for various technologies when facing uncertainties, especially the uncertainties coming from market price variations.

1.3 Research aims and objectives

Focusing on the demand-side resources in DMES, this thesis aims to study the potential and possible ways of exploiting flexibility from multiple energy vectors and sectors through DER and consumer participation, which requires detailed modeling from both technical and economic perspectives. Boosting the flexibility potential from multiple energy sectors to contribute to system reliability and security requires, firstly, understanding multi-energy demand, secondly, understanding characteristics and technical requirements of flexible resources from multiple energy sectors, thirdly, systematically considering the economic value from various markets and grid services, and lastly, assessing the business cases and investment strategies for flexible resources under uncertainty. Thus, the following objectives are defined:

- Identify the existing and grid services that the multi-energy flexible resources can participate in, and their associated values as well as commercial agreement. Identify potential markets specifically featuring DMES, which may not yet be well defined.

- Determine a methodology to model multi-energy demand from both temporal and spatial perspectives, which provides fundamental information for understanding the flexibility from the consumers' demand, and when and where this flexibility could be extracted from multiple energy sectors.
- Develop a methodology to quantify the value of flexibility from multi-energy sectors, considering technical and economic constraints of a wide range of technologies featuring multiple energy sectors. This includes proper modeling of all relevant technologies, consideration of different objectives, as well as simultaneous participation in different markets and provision of different grid services.
- Develop a methodology to assess optimal investment strategies for DMES under long-term uncertainty and develop suitable associated business cases.

1.4 Contributions

In order to achieve the aims and objectives of this research, a comprehensive, novel, integrated techno-economic modeling framework is proposed, in order to identify, quantify, and optimize the flexibility and develop relevant business cases, while addressing different areas related to flexible demand-side resources. An overview of the contributions of this thesis is illustrated in Figure I-5.

First of all, the existing and potential markets and grid services that are relevant to demand-side resources are identified and reviewed in Chapter II. This includes the values that can be extracted from participating in multiple markets and

providing grid services, as well as the commercial agreements. This review provides underlying knowledge of commercial modeling as well as business case assessment of demand-side resources. Particular contributions can also be found in the study on the distribution network reliability services, which is a potential new service that can be provided by the DMES.

Secondly, in order to understand the nature of the demand, a novel multi-energy demand model is proposed and presented in Chapter III. This model is able to conduct high-resolution electricity and heat demand from both temporal and spatial aspects, using a bottom-up approach with top-down validation. This model showcases the relationship between multiple energy sectors, which also plays a vital role in understanding where and when can the flexibility come from multiple energy demands. Moreover, based on the multi-energy demand model, a city-level MES model is developed, which aims to assess the techno-economic and environmental performances of future energy scenarios. The output of the multi-energy demand model – temporal and spatial heat and electricity demand profiles – are used to support the development of the DMES operation model.

A novel multi-markets multi-services co-optimization model for DMES operation is developed and is introduced in Chapter IV. The proposed model uses the mixed-integer linear programming (MILP) technique, aiming to find the optimal solutions for DMES with regards to multi-market participation, multi-service provision, and devices' operation, so as to maximize the techno-economic benefits from integrated customer participations. As the first contribution, this model considers a diverse range of technologies that features multiple energy sectors, for example, generator, RES, energy storage (i.e., BESS, TES, and thermal storage in

buildings), and P2G. Moreover, the model optimizes multiple energy sectors such as electricity, heating and cooling, and gas, as a whole. The second contribution is that the technical and economic constraints are modeled simultaneously. More specially, the technical constraints subject to the technical characteristics of the technologies and network, while the commercial constraints take into consideration the values of markets and services and associated commercial agreements. The proposed model is able to showcase the technical flexibility and economic flexibility of DMES, which is further demonstrated through case studies.

Last but not least, a modeling framework for developing business cases for investing DER and facilitating the aggregation concepts, is developed and presented in Chapter V. The business case of a project is assessed using cost benefit analysis (CBA) metrics, under a time of value principle. A novel investment model specifically for DMES is developed, considering the long-term uncertainties of market prices. The proposed investment model is able to find the optimal investment strategy throughout the planning horizon. The DMES operation model that is previously introduced in Chapter IV is deployed, while the information about multi-market participation, multi-service provision, and devices' operation from the DMES operation model is used to assess the business cases and finding the optimal investment strategy.

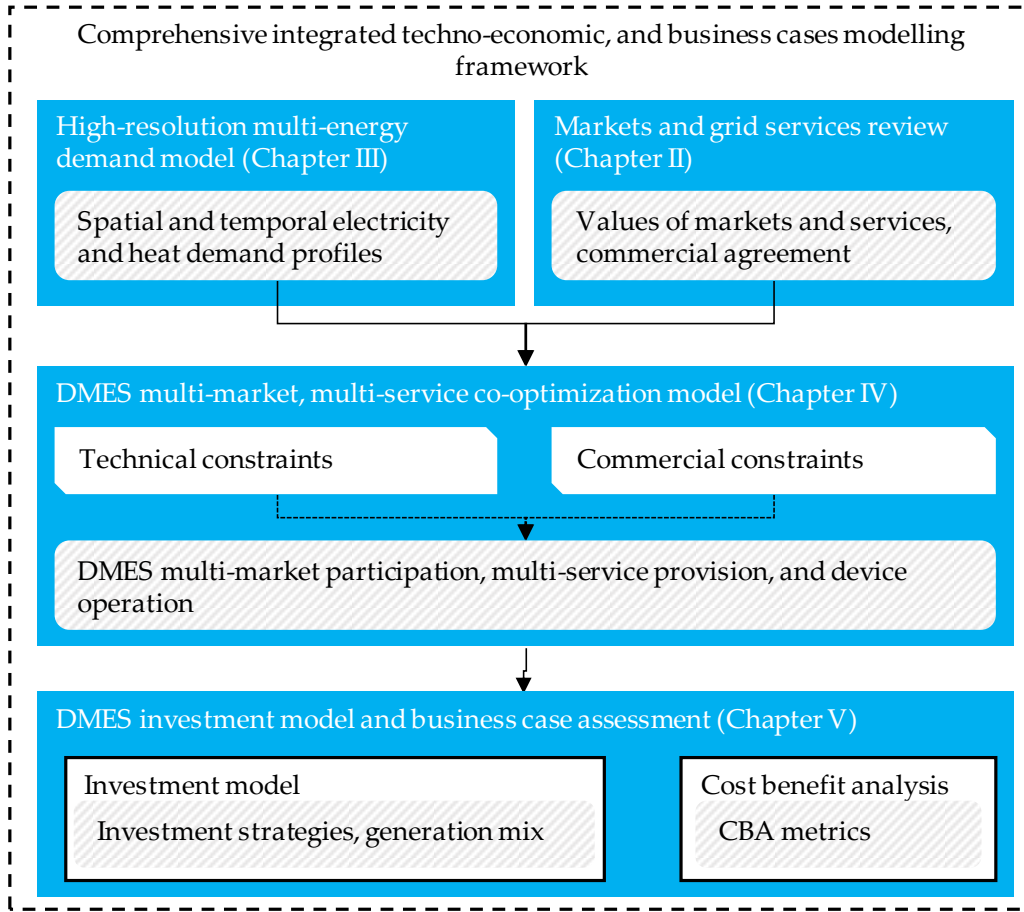


Figure I-5. Overview of contributions of this thesis

1.5 Thesis structure

The rest of the thesis is structured as follows:

Chapter II contains reviews of the literature on the means of exploiting flexibility, as well as the markets and grid services and their associated values. Moreover, Chapter III introduces the city-level high-resolution multi-energy demand model. Furthermore, Chapter IV elaborates on the multi-market multi-services co-optimization model for DMES optimal operation. Chapter V describes the DMES investment model and business case assessment framework. Lastly, Chapter VI concludes the work done in this research and highlights the contributions of this research.

Chapter II. Literature review

DMES is seen as a potential way to provide well-needed flexibility to a RES-rich power systems by utilizing demand-side resources. The business cases of DMES providing flexibility can be boosted by participating in various markets and grid services. In this chapter, a review of DMES, and existing and potential markets and grid services that are relevant to demand-side resources is carried out. This Chapter provides underlying knowledge of commercial modeling and business case assessments.

2.1 Distributed multi-energy systems

DMES are likely to play a more important role in energy transitions due to the increasing number of distributed multi-generation, multi-energy storages, and multi-energy demand. Those small-scale technologies and demand are traditionally seen as “passive” in the power system operation, which is arising the challenges for system operators to manage the power system operation and planning, including increasing energy price volatility, additional demand for ancillary services, and greater distribution network strain [7], [8]. To integrate DER and demand into power system operation and tap the potential flexibility in the demand-side resources, several aggregation concepts are carried out, [45], such as virtual power plant (VPP), and microgrids, and integrated community energy systems (ICES).

Virtual Power Plant: A VPP is an aggregation concept which controls and coordinates generation, storages, and/or loads. By controlling and coordinating DER, a VPP is able to participate in the energy market and provide various grid services,

similar to a large-scale conventional power plant [46]. The concept of VPP is firstly carried out by the authors in [47], as a ‘virtual utility’, which is able to collaborate independent entities, as well as providing grid services, without owning the corresponding assets and large-scale fundamental infrastructure upgrades. The VPP is classified into two different roles in [48], that is, commercial VPP (CVPP) and technical VPP (TVPP). Specifically, the CVPP considers a commercial aggregation of a portfolio of DER and participate in different markets, with no restriction on the geographic locations of the DER. The TVPP aggregates the DER from the same local distribution network and considers network constraints, so as to increase the visibility of DER to system operators. The VPP mainly rely on software systems to optimize the operation of technologies and remotely dispatch DER, thus they do not require large-scale fundamental infrastructure upgrades [49]. By aggregating existing DER, VPP deliver extra revenue streams to the consumers from market participation. Meanwhile, VPP contribute to the reliability and security of the system by providing ancillary services. Compared with the traditional conventional power plants, depending on its portfolio of DER, a VPP may be able to react considerably faster by changing consumers' load, dispatching distributed generators and storage.

Microgrids: A microgrid can be defined as an integrated energy system containing distributed generation, storages, and multiple loads that is able to operate as an autonomous grid, either connected or disconnect to the upstream grid [49]. One of the distinct features of microgrids is the ability of microgrids to be separated from the grid during the blackouts, which is as known as their “islanding” feature. After separated from the grid, i.e., with the islanded operation mode, the DER are operated to supply the demand and maintain a certain level of reliability

to the consumers within the microgrids. Furthermore, after the disturbances are cleared, the microgrids are able to reconnect to the grid autonomously [50]. Besides providing reliability services to the internal consumers, the microgrids are also able to provide ancillary services using their on-site generation and storages to the upstream grid at a relatively low cost [49]. Furthermore, microgrids have the potential to contribute to the reliability of the distribution networks, by restoring the power services of consumers outside the microgrids after distribution network contingencies [41], [42], [51].

Integrated community energy systems: Traditionally, the energy demand of local communities is granted by the centralized energy system. However, this top-down architecture is changing with the increasing integration of DER, to a combination of both top-down and bottom-up systems [52]. The concept of ICES is carried out in response to the changes in the local energy systems. The ICES is a complex socio-technical system featuring multi-sources and multi-product [52], which integrates different energy sectors such as electricity, heating and cooling, and transportations, and allows engagement of the consumers. The ICES consist of local generation of heat and electricity, multi-energy flexible demand, and multi-energy storages, which can range from multiple buildings of a block to an entire district. The ICES is also able to provide grid services to the neighborhood or to the upstream grid, using the flexible resources within the ICES.

Considering DER and demand within the district as a whole brings more economic benefits than considering the individual technology separately [53]. Furthermore, aggregations can also contribute to the energy services provision from the district by shifting the demand from different technologies and energy sectors

[54]. Moreover, aggregations also benefit from the natural diversity of energy demand [2]. Aggregations also enable visibility of DER to the system operator, allowing them to contribute to the system management activities and provide grid services [46]. From an economic perspective, aggregations arise the opportunities for DER to participate in various markets, which they are not able to participate in when considered individually.

Although by aggregating DER additional flexibility can be sought, without consideration of the available markets and exposure to price signals, the true potential of the DMES for maximizing local benefits and provide operational flexibility to the system cannot be exploited [2]. Optimizing DMES in electricity-related market participation (such as day-ahead (DA) and real-time (RT) electricity market) has been explored within several works, such as [55], [56], [65]–[68], [57]–[64]. However, the electricity-related market is only one of the various components of the revenue streams that are available for DMES. By exploiting the flexibility within the district, a DMES have potential to participate in the flexibility-related market, such as ancillary services market [41], [69]–[73], and DR [74]–[76]. Moreover, DMES may also provide hedging products for retailers to hedge the risk of facing volatile wholesale spot prices. The abovementioned studies only consider part of the available markets and services. Therefore, a modeling framework to quantify the flexibility from DMES is required, which should be able to capture the values from all potential revenue streams including participating in the markets and providing grid services.

2.2 Markets and grid services descriptions and values

The available flexibility from DER that can contribute to the system depends on both technical flexibility and economic flexibility. Thus, exploiting the flexibility from DER requires an understanding of their technical characteristics which determine how much operational flexibility they can potentially provide, as well as the value of the flexibility which has a great impact on their willingness to change their operation to provide flexibility, i.e., their economic flexibility.

In order to properly quantify the value of flexibility, all potential revenue streams, which relate to the participation of multiple markets and the provision of grid services, need to be understood. In general, flexibility can be traded as either power products in the energy markets, or traded as flexibility products, such as ancillary services and DR. As shown in Figure II-1, in the context of NEM, various electricity-related markets and flexibility-related markets are available for different types of participants, including the wholesale electricity spot market, ancillary services, DR market, and hedging contract market. This section provides an overview of the available electricity-related and flexibility-related markets and the grid services, in the context of Australia NEM, and their associated values.

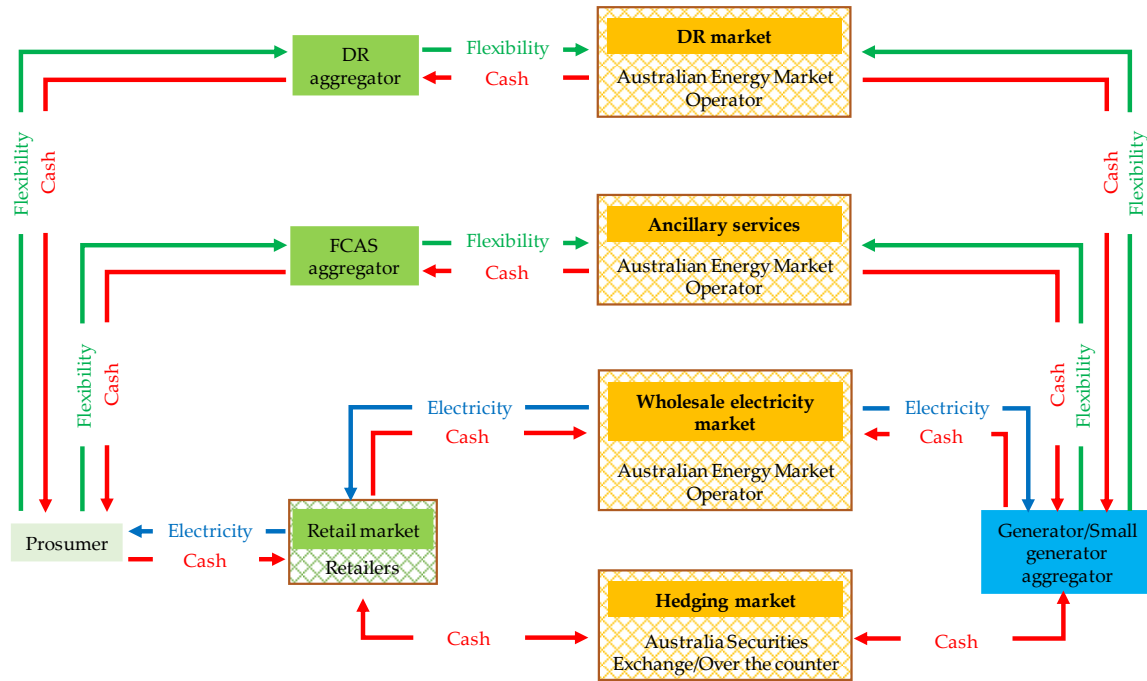


Figure II-1. Overview of electricity-related and flexibility-related markets in NEM [77]

2.2.1 Market participants in the National Electricity Market

In Australia, the NEM operates power systems of five interconnected regions, consisting of Queensland (QLD), New South Wales (NSW), Victoria (VIC), South Australia (SA), and Tasmania (TAS), which is managed by Australian Energy Market Operator (AEMO), as shown in Figure II-2.

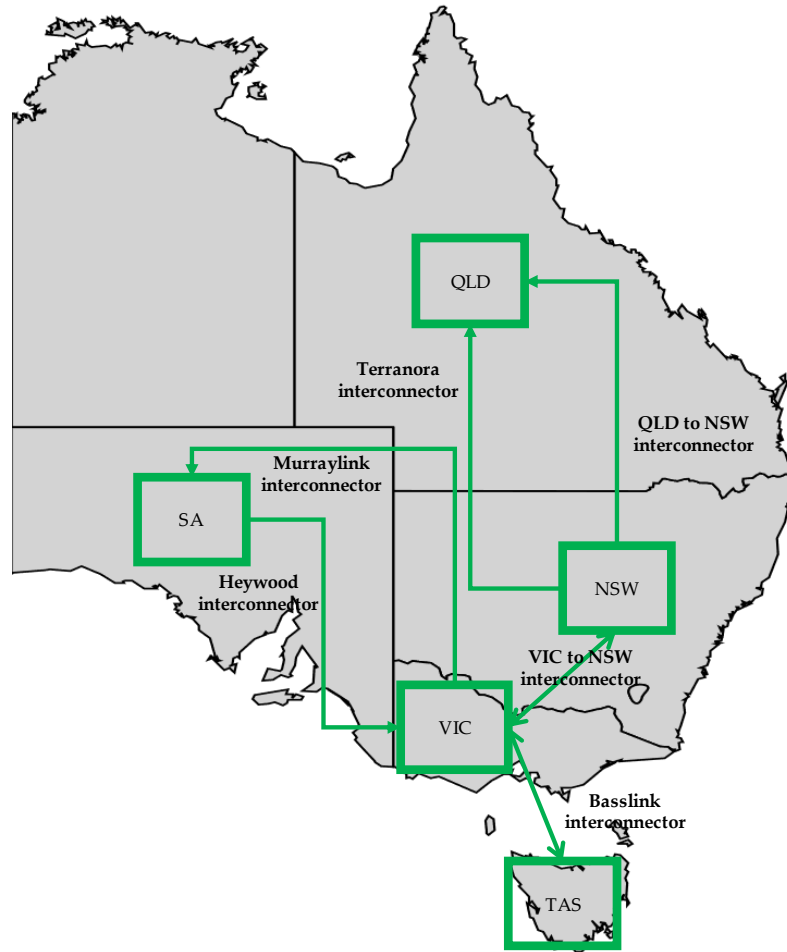


Figure II-2. Australia National Electricity Market map diagram.

In order to participate in electricity and ancillary services markets, the participants (e.g., generators, retailers, and aggregators) must register. The participant categories in the NEM are shown in Table II-1. More specifically, the major participant categories including generators, customers, small generation aggregators, and network service providers. The generators and customers are grouped into market generators/customers, and non-market generators/customers, depending on whether they participate in the wholesale market or not, i.e., buying or selling electricity in the wholesale spot market, or providing market ancillary services. Moreover, a small generation aggregator (SGA) aggregates generation units that are too small to register as a market generator, allowing them to participate in

wholesale markets and provide ancillary services. Lastly, the network service provider either own, operate or control a transmission network, i.e., transmission network service provider (TNSP), or a distribution network, i.e., distribution network service provider (DNSP), which is obligated to provide network services while obtaining incomes from either regulated incomes or market incomes.

Table II-1. Participant categories in NEM [78]

Generator	Market generator Sells electricity in the wholesale spot market and receives the payment from AEMO based on the spot prices	Scheduled generator - Has a total capacity that is greater than 30 MW, with partially or all electricity generation sold in the spot market - Participates in central dispatch process by AEMO
		Non-scheduled generator - Has a total capacity between 5 MW and 30 MW, with partially or all electricity generation sold in the spot market - Does not participate in the central dispatch process
		Semi-scheduled generator - Has intermittent output and a total capacity greater than 30 MW, with partially or all electricity generation sold in the spot market - The generation output can be limited occasionally by AEMO due to network constraints
		Ancillary services generating unit Generators that participate in one of the eight ancillary services markets
	Non-market generator All electricity generation is purchased by local retailers or customers	Scheduled generator - Has a total capacity that is greater than 30 MW - Does not participate in the wholesale spot market, and all electricity generation is purchased by local retailers or customers
		Non-scheduled generator - Has a total capacity that is less than 30 MW - Does not participate in the wholesale spot market, and all electricity generation is purchased by local retailers or customers
		Semi-scheduled generator - Has intermittent output and a total capacity that is less than 30 MW - Does not participate in the spot market, and all electricity generation is purchased by local retailers or customers

		• The generation output can be limited occasionally by AEMO due to network constraints	
Customer	Market customer	• Customers that buy electricity from the wholesale spot markets	
	Non-market customer	First-tier customer	• Customers who purchase electricity through local retailers • Does not participate in the spot market
		Second-tier customer	• Customers who purchase electricity through a market customer who is not the local retailer. • Does not participate in the spot market
Small generation aggregator (SGA)			
• Aggregates small generation units that are under 30 MW and supply electricity to a transmission or distribution system • Sell and purchase electricity from wholesale spot market			
Network service provider (NSP)			
• Own, operate, or control a transmission or distribution systems • NSPs either earn revenue from a regulated income or from spot markets by providing network services			

2.2.2 Electricity market

2.2.2.1 Wholesale market

In NEM, the electricity is traded through a real-time wholesale spot market, which is a commodities-type pool with a five-minute dispatch interval [79]. The market generators [78] submits their bids for a certain amount of energy over a set time period (i.e., a set of five-minute blocks) with specified prices. Moreover, the generator is required to submit their bid in five-minute blocks, up to one and a half days before, which can be changed at any time before the start of the dispatch process of the five-minute interval. The supply and demand are balanced in a real-time manner, where the scheduled market generators are dispatched every five-minutes under an economic dispatch approach, i.e., delivering electricity using the mix of a generation with the lowest costs. The spot price is determined based on the marginal cost of electricity generation, i.e., the most expensive electricity gen-

erating unit that is selected to run. The generators are paid for their electricity generation with the regional spot price. On the other hand, the market customers (i.e., the customers that are registered to purchase electricity from the spot markets), buy electricity from the market with the spot prices.

The average wholesale electricity prices from 2010 to 2018 are shown in Figure II-3, based on the data provided by AEMO [80]. What stands out is that the daily average wholesale electricity prices for all five states are nearly doubled in the past decade, partly due to the retirement of old coal-fired power plants and the integration of RES. Moreover, Figure II-3 also shows the seasonal fluctuations in wholesale electricity prices. In general, wholesale electricity prices are higher in the summer than in other seasons. This is a result of several factors such as high demand periods to fulfill space cooling requirements, associated with comparably low wind generation.

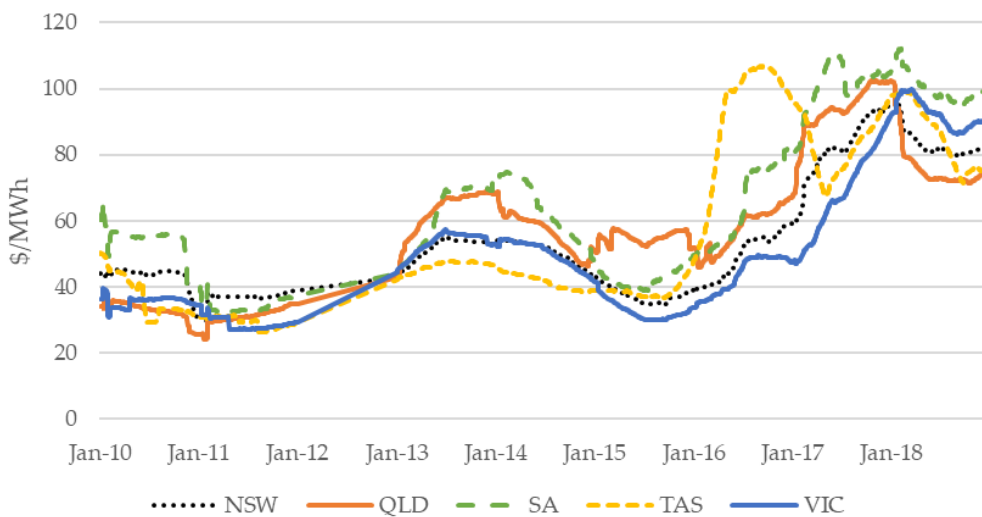


Figure II-3. Wholesale electricity market daily average prices for five states, from 2010 to 2018

The wholesale electricity price can be extremely volatile, as illustrated in Figure II-4 which shows the five-minute wholesale electricity prices for five states on

24th January 2019, based on the price data provided by AEMO [80]. The wholesale electricity prices range from the -\$1,000/MWh (i.e., Market Floor Price) to \$14,200/MWh (i.e., Market Price Cap). This volatility creates great risks, as well as opportunities to generators and to the retailers.

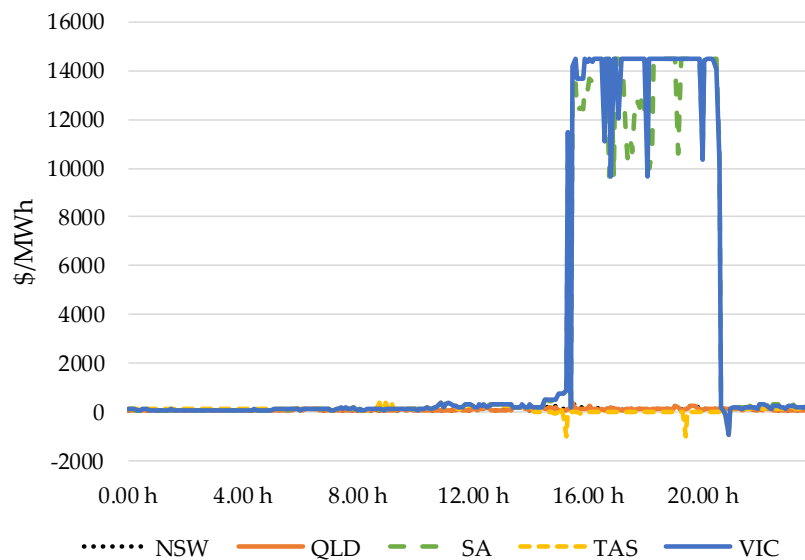


Figure II-4. Five-minute wholesale electricity prices for five states on 24th January 2019

2.2.2.2 Retail market

The retail market acts as an interface between retailers and their consumers, which allows retailers to sell electricity, gas, and energy services to consumers. The retailers purchase electricity from the spot market, and then resell electricity to their consumers with retail tariffs. The retail tariff reflects a number of different costs, including network-related charges that consist of standard network services charges and network policy costs, wholesale electricity costs which is a reflection of wholesale energy prices, retail policy costs, and good and services tax (GST), as shown in Table II-2.

Table II-2. Annual bill component of a residential electricity customer in Victoria using 4,000 kWh (without electric off-peak hot water)

Bill component		
Network related charges	Standard network services	Distribution Transmission
	Network policy costs	Interval and smart (AMI) metering Feed-in tariffs
Wholesale electricity and retail services charges	Retail policy costs	Victorian Energy Efficiency Target (VEET) Renewable Energy Target (RET) Carbon price
	Wholesale energy and retailer costs	
GST		

The retail tariffs are often made of two components, i.e., fixed charges and variable charges. The variable charges are based on the quantity of electricity consumption. Depending on the types of the tariff, the variable charges might also be charged based on when the electricity is consumed and the user's peak demand. On the contrary, the fixed charges are not related to energy usage but are charged based on a daily, monthly, or annual basis.

2.2.3 Ancillary services

Ancillary services are used by AEMO as means to maintain the security and reliability of the power system [81]. AEMO can purchase ancillary services from market participants, by using either *market ancillary service* agreements, or *non-market ancillary service* agreements [81]–[83].

The ancillary services in NEM are grouped into three categories, i.e., frequency control ancillary services (FCAS), network support and control ancillary services (NSCAS), and system restart ancillary services (SRAS). Among all three ancillary services, FCAS is market ancillary services, while NSCAS and SRAS are non-market ancillary services. The categories of ancillary services are illustrated in Figure II-5, while their descriptions and value are detailed in the following sections.

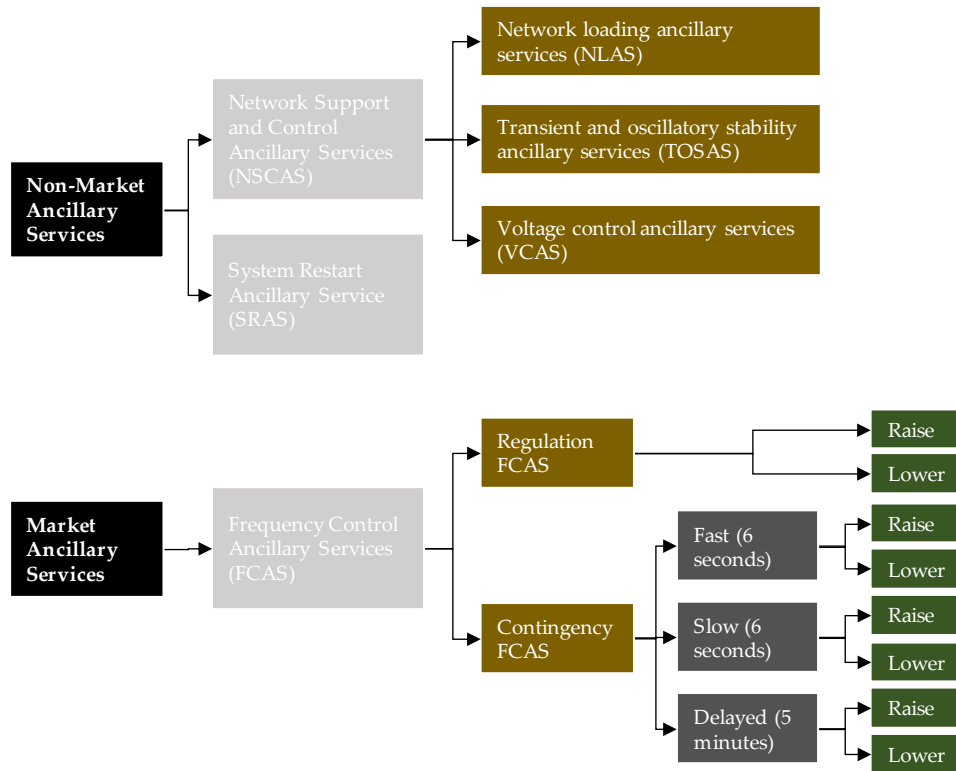


Figure II-5. Categories of ancillary services

2.2.3.1 Market ancillary services – Frequency Control Ancillary Services

FCAS is used as a means to monitor the system's frequency, by keeping the balance between supply and demand. There are two types of services, namely, raise FCAS and lower FCAS. Raise FCAS is used to correct frequency drops in the systems, by increasing the generation or lowering the demand. on the contrary, lower FCAS is used to lower the system frequency, by increasing the demand or decreasing the generation.

The FCAS markets can be grouped into two categories, i.e., regulation FCAS and contingency FCAS, as detailed in Table II-3 [81]–[87]. Regulation FCAS is used to continuously correcting the minor frequency deviation, which is dispatched through Automatic Generation Control (AGC) following AEMO's signal every

four seconds so that to maintain the frequency within the normal frequency operating band. Contingency FCAS is used to correct major frequency deviations following contingency events. This type of FCAS is provided by the technologies that are able to detect frequency deviation and can respond to correct the system frequency. Contingency FCAS is further grouped into fast, slow, and delayed contingency FCAS. The fast contingency FCAS respond within 6 seconds and provide an orderly transition to slow FCAS, the slow contingency FCAS respond within 60 seconds and provide an orderly transition to delayed FCAS, and the delayed contingency FCAS respond within 5 minutes after contingency and retain the services for 10 minutes or notified by central dispatch.

Table II-3. FCAS categories in NEM [81]–[87]

Services		Main technical requirements	Criteria for activation	Recovery
Regulation FCAS	Regulation raise FCAS	Continuously correcting minor frequency deviations, so as to maintain system frequency within 49.9 Hz and 50.1 Hz	Minor frequency drops, i.e., 49.85 - 50.0 Hz	Loads and generators pay
	Regulation lower FCAS		Minor frequency raises, i.e., 50.0 - 50.15 Hz	Loads and generators pay
Contingency FCAS	Contingency fast raise FCAS (6 seconds)	Respond within the first 6 seconds of the frequency disturbance, and provide an orderly transition to contingency slow FCAS (60 seconds)	Frequency changes below 49.85 Hz	Generators pay
	Contingency fast lower FCAS (6 seconds)		Frequency changes above 50.15 Hz	Loads pay
	Contingency slow raise	Respond within the first 60 seconds of a major	Frequency changes below 49.85 Hz	Generators pay

Chapter II. Literature review

	FCAS (60 seconds)	frequency disturbance, and provide an orderly		
	Contingency slow lower FCAS (60 seconds)	transition to contingency delayed FCAS (5 minutes)	Frequency changes above 50.15 Hz	Loads pay
	Contingency delayed raise FCAS (5 minutes)	Respond within first 5 minutes of a major frequency disturbance, and sustain the response	Frequency changes below 49.85 Hz	Generators pay
	Contingency delayed lower FCAS (5 minutes)	for 10 minutes or notified by central dispatch	Frequency changes above 50.15 Hz	Loads pay

In the context of NEM, the FCAS are traded through the wholesale spot market, with five-minute dispatch intervals. The price for each of the eight FCAS markets is determined every five-minute. Similar to the wholesale electricity market, the participants are required to submit their bids in a five-minute time interval up to one and a half days before and can modify the bids at any time before the dispatch process starts. FCAS providers are paid for the capacity that is made available for FCAS, based on the market prices. This payment is made based on availability, regardless of whether the services are called or not.

The payments of FCAS are recovered from market participants, as detailed in Table II-3. The recovery of contingency raise FCAS payments is made by generators, while the contingency lower FCAS payments are recovered from customers. The regulation FCAS payments are recovered on a “causer pays” basis, i.e., the costs of regulation FCAS are recovered by the market participants who are responsible for causing the need for the services [83].

The five-minute FCAS prices for eight FCAS market of VIC on 24th January 2019 is shown in Figure II-6, while the average FCAS prices in VIC for the year 2018 is illustrated in Figure II-7. The price data is based on [80]. It can be seen that the regulation FCAS markets have the highest value among all. Moreover, for contingency FCAS, the raise contingency FCAS markets have higher values than lower contingency FCAS markets. Furthermore, the fast raise FCAS holds the highest value among all contingency raise FCAS markets.

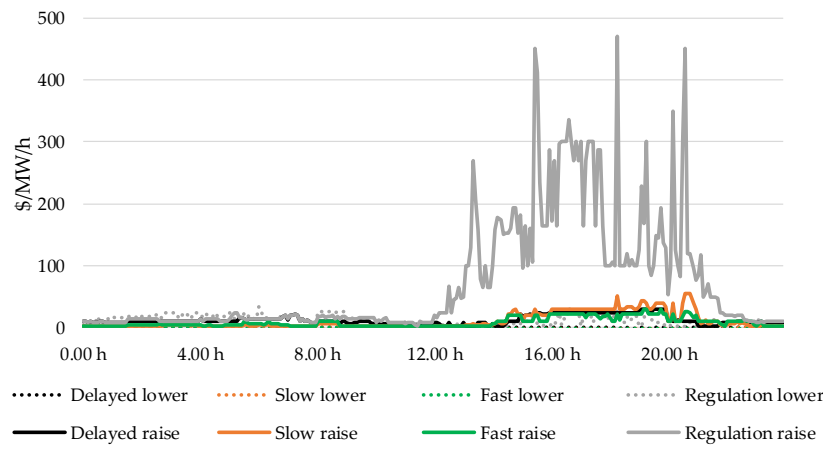


Figure II-6. Five-minute FCAS prices in VIC on 24th January 2019

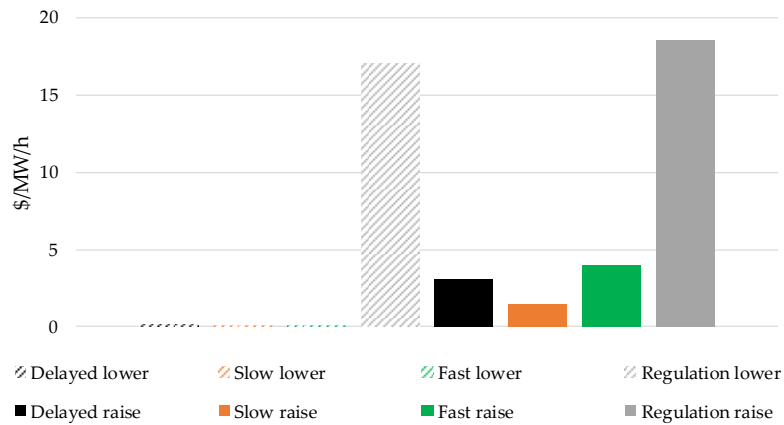


Figure II-7. Average FCAS prices in VIC in 2018

2.2.3.2 Non-market ancillary services

As mentioned before, the non-market ancillary services consist of NSCAS and SRAS.

The NSCAS is designed to maintain the reliability and security of the power system, as well as to maintain or to increase the transmission network's power transfer capability. The NSCAS are grouped into Voltage Control Ancillary Services (VCAS), Network Loading Control Ancillary Service (NLCAS), and Transient and Oscillatory Stability Ancillary Services (TOSAS). More specifically, VCAS is used to maintain the voltage within the prescribed standards; NLCAS controls the power flow to be within the physical limits of the network elements; TOSAS maintains transient and oscillatory stability within the power system after major events.

The SRAS is used as reserves to restart the system after a complete or partial system blackout. This is often provided by the generators which are able to start without drawing power from the grid after a major supply disturbance and can deliver the power for a certain period of time [88].

Both NSCAS and SRAS are traded through long-term ancillary service contracts. The payments that are made to the non-market ancillary service participants are a mixture of enablement payments, availability payments, testing payments, and usage payments. The enablement payments are paid when the service is enabled, while the availability payments are made when the service is available. Furthermore, the testing payments are paid to cover the costs of annual testing, while the usage payments are made for when the service is delivered. However, the values of NSCAS and SRAS are not publicly known.

2.2.4 Fast frequency response

The uptake of the inverter-based technologies such as wind and solar and the decrease of synchronous generation lead to a higher RoCoF. A high RoCoF following contingency events can lead to rapid frequency deviations, which creates risks to manage the power systems. This highlights the needs of a faster FCAS, in order to maintain the reliability and security of the power system with a high RoCoF. In this context, fast frequency response (FFR) is seen as a new potential way to efficiently manage the fast frequency dynamics in SA, which has a high RoCoF due to the large penetration of wind and solar.

FFR can be defined as a fast increase or decrease of active power from generators or loads, in response to a drop or raise in system frequency, within a timeframe of two seconds [89]. FFR can be provided by a range of technologies, such as wind, solar, batteries, flywheels, supercapacitors, and demand response.

There are currently no FFR-related markets in the context of Australia. However, the AEMO is considering creating a new FFR market while placing FFR obligations on the new RES generation [90] in the state of SA. This could potentially be another valuable revenue stream for DER.

2.2.5 Distribution network reliability services

Nationwide, under the National Electricity Rules (NER), the DNSP are incentivized to improve their service performance in terms of *reliability of supply, quality of supply, customer services, and guaranteed service level*, under the Service Target Performance Incentive Scheme (STPIS) [91]. Both bonuses and penalties may be applied to the DNSP depending on their service performances, which can be as high as 7% of their annual revenue [91]. The DNSP are also required to compensate the

consumers experienced with the service performances worse than the lower limit. In terms of the reliability of supply, the widely used standards to measure reliability performances of the DNSP are *System Average Interruption Duration Index* (SAIDI), and *System Average Interruption Frequency Index* (SAIFI) [92]. SAIDI represents the average length of the interruptions in a year, while SAIFI indicates the average number of interruptions each year. The DNSP are required to set their own reliability target in terms of SAIDI and SAIFI.

Distribution network reliability services may also be provided by grid-connected microgrids. As discussed in the previous section 0, a microgrid has the ability to ride through the contingency event by operating as an island. Besides providing reliability services to the internal consumers, microgrids also have the ability to restore neighborhood consumers after a contingency, using its surplus generation [42], [43], [51]. This can potentially help the DNSP to restore consumers in a shorter amount of time to help with improving their SAIDI.

The distribution networks are often designed with several kinds of redundancy at a medium voltage level. In urban areas, the distribution network is often operated as an open-loop via switches [91], as shown in Figure II-8. The “normally open point” (NOP) allows the consumers to be connected to an alternative point of supply after contingency, so as to improve the reliability of the network. An example is shown in Figure II-8, which represents an urban distribution network under a) normal, b) contingency, and c) emergency operation conditions. After the contingency occurs at a feeder, all consumers connected to this feeder are discounted, in this case, C1, C2, and C3. After isolating the contingency, the consumers, that can be reconnected to their original feeder, i.e., C1, are restored (see Figure

II-8.b). In order to restore the consumers that are isolated from their original feeder, i.e., C3, the NOP is closed, in order to connect C3 to an alternative supply (see Figure II-8.b). Consumers C2 may be reconnected to the neighborhood or the original feeder after isolating the contingency (see Figure II-8.b).

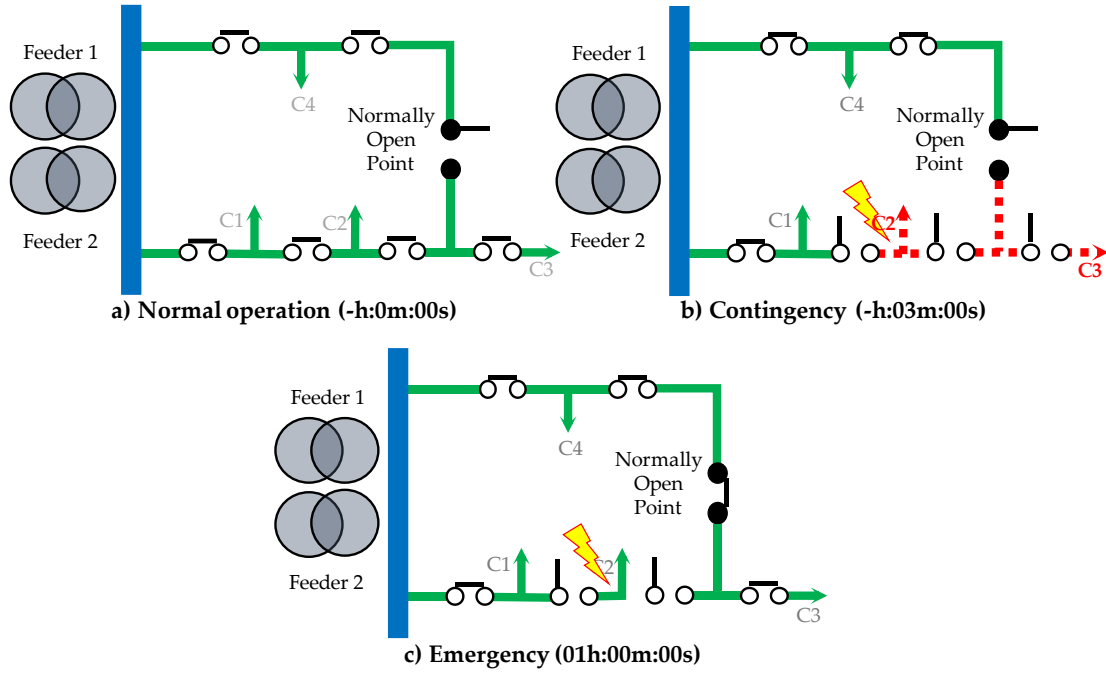


Figure II-8. Distribution network under a) normal operation condition, b) contingency operation condition, and c) emergency operation condition [41]

Unlike FCAS and FFR, which can be provided by a wide range of technologies, the distribution network reliability services that can be provided by a grid-connected microgrid is subject to the characteristics of the technologies within the microgrid, the location of the microgrid, and the location of the contingency [41]–[43]. An example of microgrid providing reliability services to the DNSP is shown in Figure II-9, where the contingency happens at two locations, i.e., Figure II-9.b and Figure II-9.c, respectively. In the first contingency location, i.e., Figure II-9.b, the microgrid is able to supply consumers C3 for a few minutes before the NOP is

closed. In the second contingency location, i.e., Figure II-9.c, the microgrid may be able to supply consumers C3 for a few hours, until the contingency is cleared.

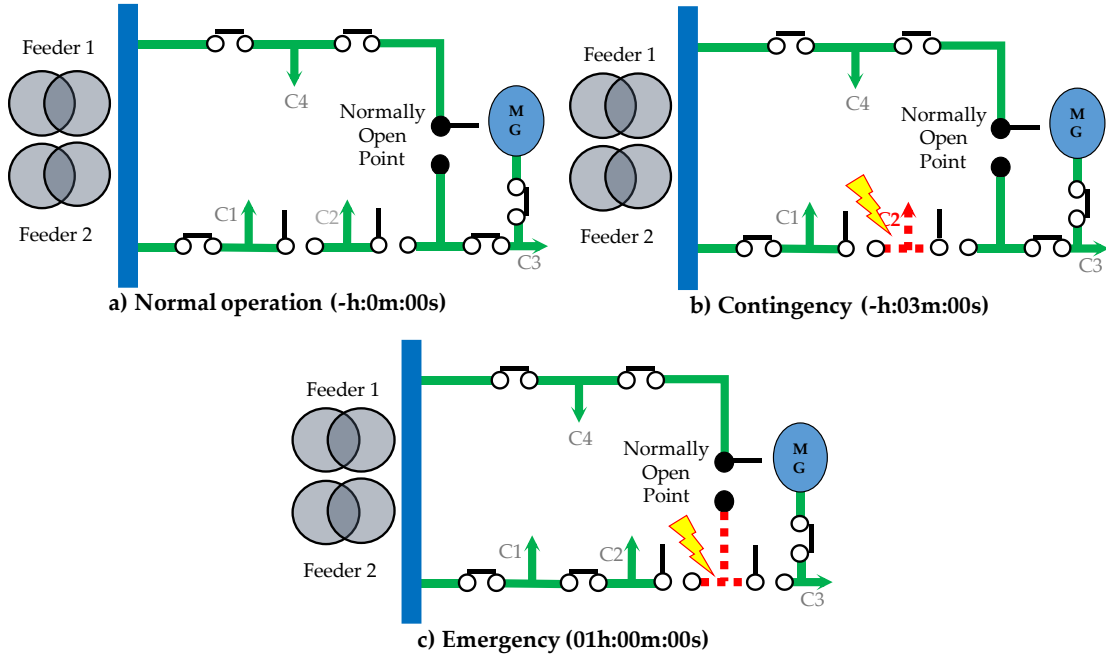


Figure II-9. Distribution network under a) normal operation condition, b) contingency operation condition, and c) emergency operation condition, with the microgrid providing reliability services to the neighborhood with different contingency locations [41]

Although the microgrids have great potential to provide distribution network reliability services, the value of providing such services to the DNSP is not very well defined.

2.2.6 Demand response market

Demand response can be defined as consumers intentionally decrease or increase their electricity consumption in response to incentives and price signals [93]–[95], which can be done by reducing, reshaping, or shifting their electricity consumption through utilizing storage or switching on back-up generation for a limited time during the extreme peaks throughout the year.

In NEM, there are four types of demand response, namely, *wholesale demand response*, *ancillary service demand response*, *network demand response* and *emergency demand response* [96]. The description of the demand response markets is illustrated in Table II-4.

Wholesale demand response and ancillary service demand response participate in the wholesale level market. More specifically, the wholesale demand response is a price-driven demand response, where the customers modify their demand in response to the wholesale electricity prices. In the ancillary service demand response, the energy users use their demand response to actively participate in FCAS market.

On the contrary, network demand response and emergency demand response do not participate in a wholesale market level but are given incentives to provide the services. The network demand response is employed to help DNSP to provide network services to customers [97]. The emergency demand response is employed by system operators during supply emergencies and is currently participate in Reliability and Emergency Reserve Trader (RERT) [98].

Table II-4. Description of demand response markets in NEM

Type	Description
Wholesale demand response	The wholesale demand response is a market-driven demand response. The demand response occurs as a change in the quantity of electricity purchased from the wholesale market in response to wholesale market prices.
Ancillary service demand response	Ancillary service demand response is deployed in the response to the imbalances between supply and demand, by participating in FCAS markets.

Emergency demand response	Emergency demand response is employed as an emergency lever by the system operator during supply emergencies. The emergency demand response is centrally dispatched or controlled, which is often provided by the out-of-market reserves.
Network demand response	Network demand response is used to help DNSPs to provide network services to their consumers.

2.2.7 Hedge contract market

In the context of NEM, electricity can only be traded the wholesale energy markets through a central pool. Due to the variability in the demand and supply, the electricity price can range from the -\$1,000/MWh (i.e., Market Floor Price) to \$14,200/MWh (i.e., Market Price Cap) [99]. The volatility of spot prices creates significant risks for both retailers and generators. In order to manage the risks of spot price volatility, retailers and generators have the choice of entering into financial market instruments, so-called ‘derivatives’ or ‘hedge’ contracts.

There are two main ways for retailers and generators to trade derivative instruments [100]:

- Over the Counter (OTC) hedge contract, where the contract is traded as a direct agreement between two parties.
- Trading futures and options on an exchange, i.e., Australian Securities Exchange (ASX).

Two core contract types of derivatives are swaps and caps, and example of swaps and caps is shown in Figure II-10.

The cap contract is illustrated at the top of Figure II-10. Under a cap contract (or simply “caps”), two parties agree on a strike price. During the contract period, if the wholesale price is above the strike price, the cap seller (usually a generator)

needs to pay the difference to the buyer of the cap (usually a retailer). In return, the cap buyer needs to pay the cap seller a fee. One cap contract that is commonly traded in the NEM has a strike price of \$300/MWh, which is often sold as an up-front payment paid by cap buyers to cap sellers.

The swap contract is illustrated at the bottom of Figure II-10. A swap contract (or simply “swaps”), which is also referred to as “contract of differences”, allows the buyers and sellers to lock the electricity at an agreed price. During the contract period, swap buyer (usually a retailer) and swap seller (usually a generator) agree on a strike price for trading a certain amount of electricity. When the electricity prices exceed the strike prices, the swap buyer receives a payment from the swap seller. On the contrary, when the electricity prices are lower than the strike prices, the swap seller receives payment from the swap buyer.

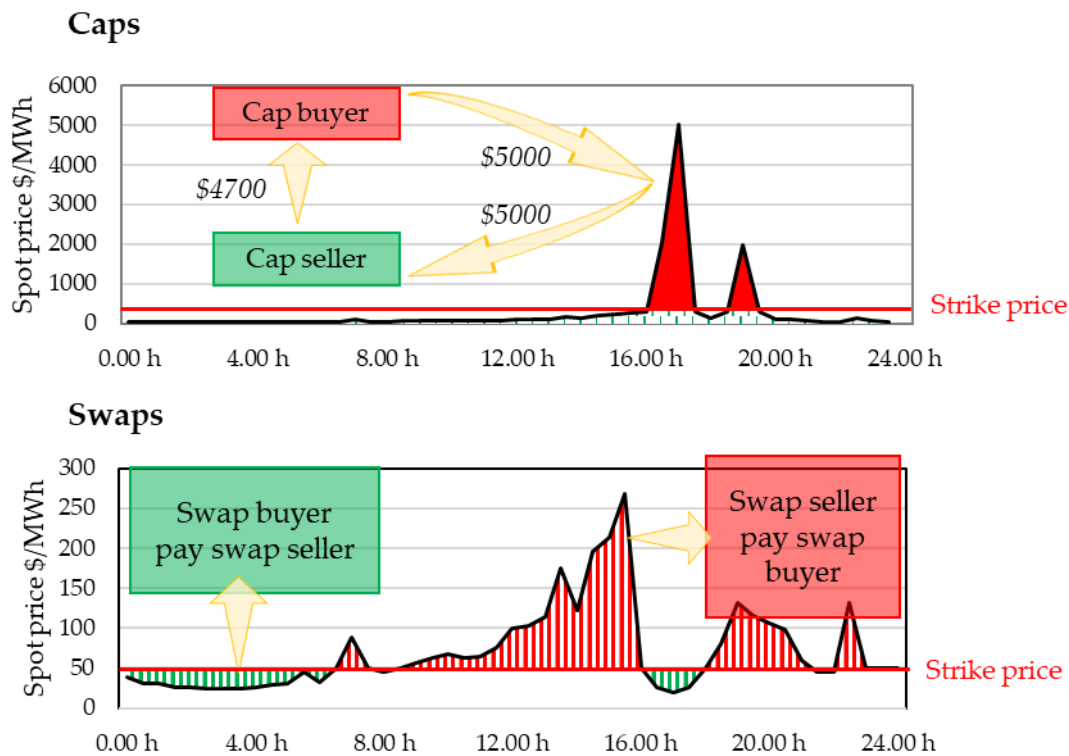


Figure II-10. Examples of caps (top) and swaps (bottom) [77]

The VIC \$300 cap contract that is traded on ASX is illustrated in Figure II-11. It can be seen that the first quart has the highest price compared to the other three quarters, as the likelihood of having peak electricity prices is higher in the summer than other seasons.

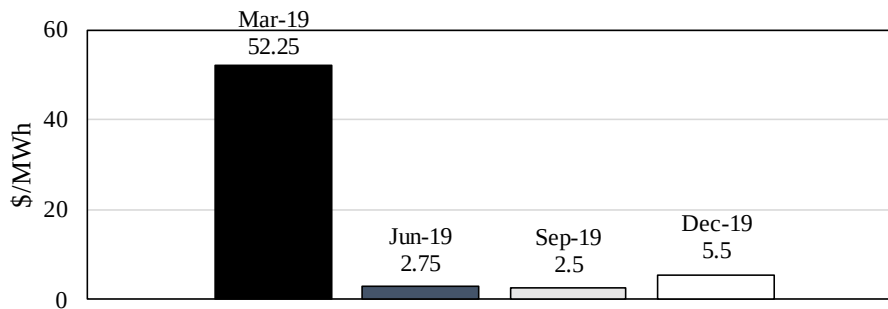


Figure II-11. VIC \$300 cap contract prices traded on ASX

2.3 Summary

This chapter firstly introduces MES and various aggregation concepts of DER. VPP, microgrids, and ICES are introduced as a means to efficiently and economically control and coordinate DER, and exploit flexibility from consumers' participation. From a technical perspective, aggregations can boost the flexibility from the DER and provide grid services, take advantage of the natural diversity of the loads, and increase the visibility of the DER to the system operators. Furthermore, aggregations allow small scale technologies to participate in the markets which leads to more economic benefits.

Subsequently, this chapter describes various markets relevant to DMES in the context of the NEM. The electricity markets are firstly introduced, including the wholesale electricity market and retail electricity market, followed by the ancillary services, including market ancillary services (i.e., FCAS) and non-market ancillary

services (i.e., NSCAS and SRAS). Then, the potential grid service FFR is introduced and the study of distribution network reliability services is conducted, before the description of the DR markets. Lastly, the hedging contract market is briefly introduced.

The value that can be extracted from the various markets and grid services will be specific to the technologies within the DMES. Besides electricity-related markets, the DEMS are also suitable for participating in flexibility-related markets using distributed generation and storages, while the flexible demand is suitable for the flexibility-related markets or services with low call frequency, such as contingency FCAS markets and emergency demand response. Furthermore, by using distributed generation and storage units, DMES are also suitable for providing hedging products to the retailers. Moreover, grid-connected microgrids also have the potential to provide distribution network reliability services to DNSP. The economic benefits from multiple markets can be substantial, which allows the DMES to realize great values from market participation at relatively low costs. The electricity-related, flexibility-related, and financial markets that are introduced in this section provide fundamental knowledge of the economic studies in Chapter IV.

Chapter III. Multi-energy demand model

Energy demand is the building bricks of analysing demand-side flexibility. In this Chapter, a high-resolution multi-energy demand model is carried out, which provides fundamental information on the heat and electricity demand from different groups of consumers, aiming to help understanding where and when can the flexibility be extracted from multiple energy sectors. This model is demonstrated by a case study that is based on Greater Manchester.

3.1 Introduction

Urban areas occupy 3% of the land surface, while contribute to up to 80% of the global greenhouse gas (GHG) emissions [101] and consume about 76% of the natural resources [101]. The dramatically increasing of urbanization is thus bringing gradually attention paid on city-level multi-energy systems with respect to the decarbonization of smart cities to fight against climate changes. In terms of smart city development, energy demand modeling with high resolutions from both spatial and temporal aspects provides fundamental information to MES analysis. A heat demand model that is able to model half-hourly heat profiles by extracting historical temperature and gas consumption is built by Sansom and Strbac [102]. Nonetheless, in this work, only the temporal aspect is considered at a national level. A geographical information system (GIS) based model which takes into account the spatial aspect in order to assess the energy requirements for urban areas is developed in [103]. However, the temporal characteristics are not appropriately presented in the paper. Only a few studies consider both temporal and spatial aspects

in the existing literature. A cooling and heating demand model is carried out in [104] in order to find out the optimal sustainable energy solutions for urban areas. Although both spatial and temporal aspects were considered, the model did not take into account different building characteristics (e.g., building types, insulation levels) which results in various types of load profiles.

On the above premises, a high-resolution multi-energy demand model is developed, aiming to provide information on the heat and electricity demand from different groups of consumers such as residential, commercial, and industrial, so as to understand *where* and *when* can the flexibility be extracted from multiple energy sectors. Moreover, the proposed model also gives insights on understanding users' behavior which plays a vital role when exploiting the flexibility from demand-side resources. The multi-energy demand from both temporal and spatial perspectives can also be seen as the fundamental knowledge for the DMES operation model and investment model and for developing business cases of DER.

The proposed model uses a bottom-up approach, i.e., from the single house level to the postcode district level, with a top-down validation using the available information. The multi-energy demand model also takes into account of various building types and diverse occupancy behaviors, so as to enable accurate modeling of building characteristics. A city-level MES analysis model framework is further developed based on the multi-energy demand model to assess the environmental and techno-economic performances for different low carbon future scenarios.

In the rest of this chapter, the modeling framework of the multi-energy demand model, which draws on the work published in [105] is firstly introduced in section 3.2, followed by a real-world application based on Greater Manchester

which is presented in section 3.3. Lastly, section 3.4 provides conclusions and summaries of this chapter.

3.2 Modeling framework

The city-level MES modeling framework, including a multi-energy demand model and an operation model, is presented in Figure III-1. This model is based on both spatial and temporal aspects. In terms of spatial aspect, postcode districts are used as geographical reference zones. This is because the detailed information on building types and energy consumption is often available at the postcode level. Moreover, in the distribution network, the assets can be identified with regards to the postcode area. Thus, the modeled energy demand profiles can also be used to guide the network planning. In terms of temporal aspect, the energy demands are modeled based on a half-hour resolution⁵, which is in line with the UK energy market set-up.

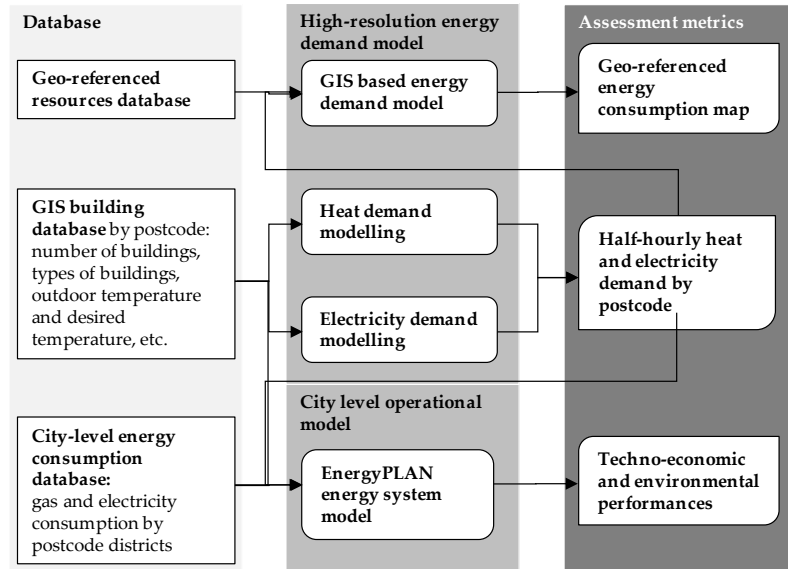


Figure III-1. City-level MES modeling framework

⁵ This model is suitable for higher temporal and spatial resolutions.

Chapter III. Multi-energy demand model

First of all, a database including the *geo-reference resources database*, the *GIS building database by postcode*, and the *city-level energy consumption database*, has been created. The GIS building database by postcode consists of the information of buildings classified into different attributions, outdoor temperatures and building desired temperature. The city-level energy consumption database includes the available energy consumption data. The database is used as input data for the high-resolution energy demand model and the operational model.

The high-resolution energy demand model is used to model half-hourly electricity and heat demand by postcode area as well as to build the geo-referenced energy consumption map. More specifically, the high-resolution energy demand model consists of the *heat demand model*, the *electricity demand model*, and the *GIS-based energy demand model*. The heat demand model and electricity demand model are used to model half-hourly heat and electricity demand indexed by postcode zones and customer sectors. The GIS-based energy demand model is built based on the energy demand profiles generated by the heat demand model and electricity demand model, as well as the geo-reference resources database, which is used to generate the geo-referenced energy consumption map. The detailed modeling approach is presented in section 3.2.2.

The city-level operational model aims to assess the techno-economic and environmental performances of the modeled city and is built based on the EnergyPLAN simulation tool. The input data include the half-hourly energy demand and energy consumption database. The modeling approach for the city-level operational model is presented in section 3.2.3.

3.2.1 Data collection

In the data collection step, a database that includes the geo-reference resources database, GIS building database, and energy consumption database, is built.

The geo-reference resources database is used as fundamental information when developing the energy consumption map. The GIS building database is built based on [106], which provides information on the insulation level of buildings, the number of various types of buildings, building desired temperature, building location, and environment temperature. The energy consumption database consists of gas and electricity annual and daily consumption, which is obtained from [107]. The abovementioned database is used as input data for the high-resolution energy demand model and operational model.

3.2.2 High-resolution energy demand model

The high-resolution energy demand model consists of heat demand modeling, electricity demand modeling, and GIS-based energy demand modeling [105]. The heat demand and electricity demand are modeled for each postcode district at half-hour interval using a mix of bottom-up approach considering different building characteristics, and top-down validation analysis based on available energy consumption (gas, electricity, heat) at sub-national level [108] and network information. The simulation results are then used as input data of the GIS-based energy demand model to generate the geo-reference energy consumption maps. In this section, the details of the high-resolution energy demand model from both temporal and spatial perspectives, including heat demand model, electricity demand model and GIS based energy demand model are introduced.

3.2.2.1 Heat demand modeling

The city-level heat demand model is a development of the previous study that was proposed for Greater Manchester [109]. The heat demand modeling generates the time series of the heat demand of different customer sectors (i.e., domestic, commercial and industrial) for different reference zones (i.e., postcode districts). In order to do so, the daily heat demand and intraday heat demand in half-hour intervals are firstly modeled, both of which are introduced in the following sections.

3.2.2.1.1 Daily heat demand modeling

The sub-regional daily heat demand is firstly modeled based on the available information, i.e., the regional daily gas consumption [107], annual heat demand at postcode level that is available at [106], and historical temperature. More specifically, the regional daily heat demand by customer sectors $DH_{d,c,p}$ is firstly modeled based on historical daily temperatures and daily gas consumption [102]. The postcode level daily heat demand by customer sectors $dh_{d,c,p}$ is then distributed from the regional daily heat demand $DH_{d,c,p}$, using the ratio of postcode annual heat demand $AH_{c,p}$ and regional annual heat demand $AH_{c,r}$ (see equation (III-1)):

$$dh_{d,c,p} = \frac{DH_{d,c,p}AH_{c,p}}{AH_{c,r}} \quad (\text{III-1})$$

For all $d \in \mathbf{D}$, $c \in \mathbf{C}$, $p \in \mathbf{P}$

3.2.2.1.2 Intraday heat demand modeling

In order to generate the half-hourly time series of the heat demand, the intraday heat demands for typical days are firstly modeled. The intraday heat demand

for each postcode district is used to “scale-down” the daily heat demand into heat demand profiles with half-hour resolution. This is done using a bottom-up approach, which can also be validated with a top-down application with available information.

The intraday heat demand for individual buildings with different building characteristics, i.e., type of building and insulation level, was carried out first by previous studies [44] [47] [48] using EnergyPlus [111]. The flow chart of intraday heat demand modeling is shown in Figure III-2. The input data can be categorized into three sets, i.e., the model of typical buildings, outdoor temperature, and desired internal temperature, while the output is the intraday heat demand profile.

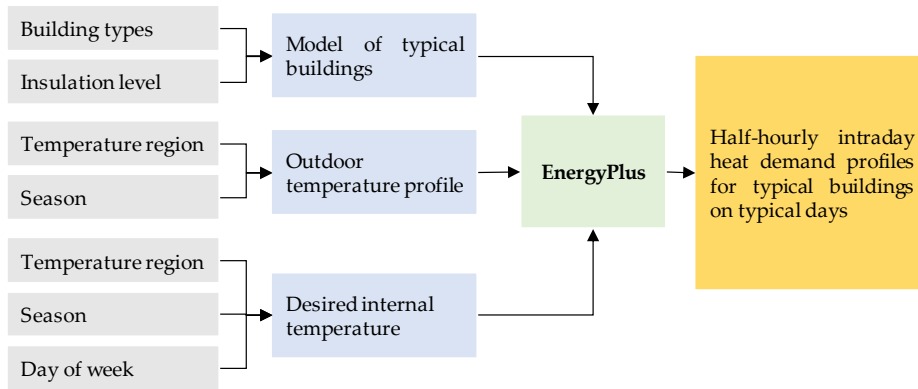


Figure III-2. Flow chart of half-hourly intraday heat demand profiles modeling

Model of typical buildings, outdoor temperature profiles, as well as desired internal temperatures, are first determined. In order to model typical buildings, different building characteristics are considered, including building types and insulation levels. The building types are grouped into detached houses, semi-detached houses, terraced houses, flats, factories, warehouses, offices, and retails. In terms of insulation levels, the individual buildings are classified into three different insulation levels, i.e., poor insulation level, medium insulation level, and good

insulation level. The insulation levels are classified based on statistics on the Energy Efficiency Rating for each building type [112]. The insulation levels are highly correlated with the building construction time [113]. Thus, the buildings that are constructed before 1944 are grouped into the poor insulation level, the buildings that are constructed between 1945 to 1984 are assumed to have the medium insulation level, while the buildings that are constructed after 1985 are seen as having the good insulation level. The details of the correspondence of the building construction time and the insulation level can be found in Table III-1. The temperature region and seasons of the year are used to generate the outdoor temperature profiles. The temperature region is based on the geographical region, i.e., north Great Britain, central Great Britain, and south Great Britain. The seasons of the year include winter, midseason, and summer. The desired internal temperature is defined based on the temperature region, the season of the year, and the day of the week (e.g., weekday and weekend).

Table III-1. Building insulation level classification

Building construction time	Insulation level
Before 1944	Poor insulation level
Between 1945 to 1984	Medium insulation level
1985 and later	Good insulation level

The output from the EnergyPlus model is the half-hourly intraday heat demand by building types on typical days. As an example, Figure III-3 illustrates the half-hourly intraday heat demand profile for different residential house types with the medium insulation level, which are located in North West England, on A) a typical winter weekday, and B) a typical winter weekend. Among all the building types, detached houses have the highest heat demand. On winter weekdays, the domestic buildings experience two peaks (see Figure III-3.A). More specifically,

the morning peak happens around 7.00h while the evening peak happens around 18.00h, which corresponds to the morning wake up time and evening return time respectively. Low heat demand is experienced during business hours on the weekdays. In terms of weekends, the morning peak is shifted to 9.00h while the evening peak remains at 18.00h. Higher heat demands are observed during the day on weekends compared to weekdays, while the peak heat demand is lower than the peak heat demand on weekdays. On the contrary, the non-domestic buildings show different trends of heat demand, as shown in Figure III-4. It can be seen that for non-domestic sectors, the heat demand is concentrated during business hours on weekdays. During the weekend, the heat demands for most of the non-domestic buildings are minor, except for warehouses.

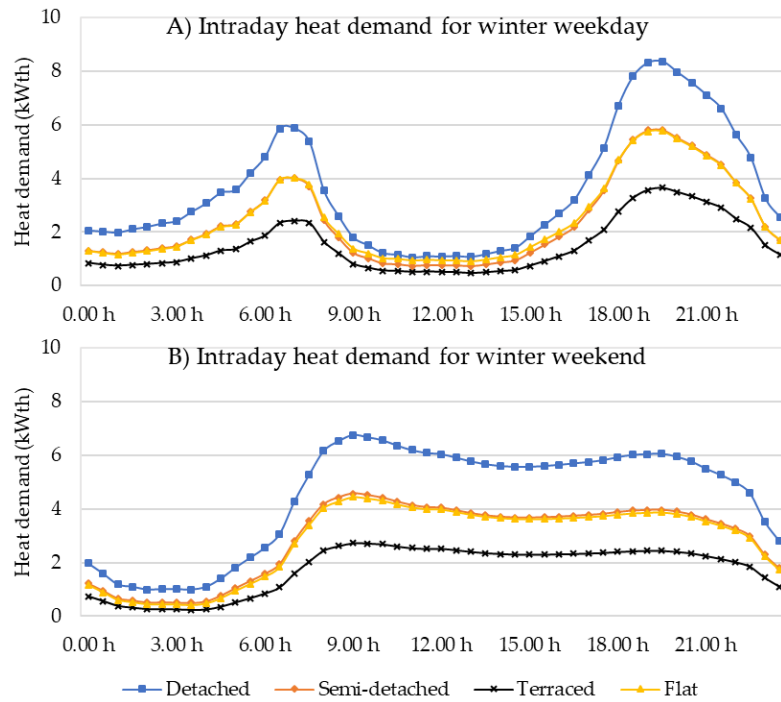


Figure III-3. Intraday heat demand profile for different types of domestic buildings with medium insulation level on A) typical winter weekdays, and B) typical winter weekends [105]

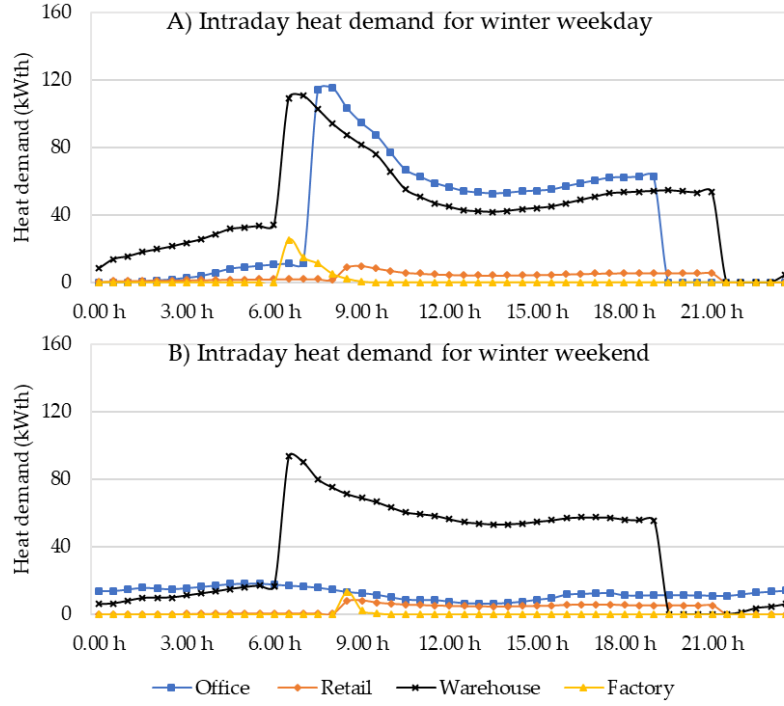


Figure III-4. Intraday heat demand profile for different types of non-domestic buildings with medium insulation level on A) typical winter weekdays, and B) typical winter weekends [105]

After generating intraday heat demand profiles for individual buildings, the intraday head demand profiles for postcode districts are modeled based on the number of different types of buildings in postcode districts [106] and the insulation levels of the buildings [114]. The intraday heat demand profiles are the aggregations of the collections of different types of building's intraday heat demand profiles (see equation (III-2)). The half-hourly heat demand can be scaled from the daily heat demand, which is calculated using equation (III-1), using (III-3).

$$H_{t,c,p} = N_{c,p} H_{t,c} \quad (\text{III-2})$$

$$h_{t,c,p} = \frac{dh_{d,c,p} H_{t,c,p}}{\sum_{t \in \mathbf{T}} H_{t,c,p} \Delta t} \quad (\text{III-3})$$

For all $t \in \mathbf{T}$, $c \in \mathbf{C}$, $p \in \mathbf{P}$.

3.2.2.2 Electricity demand modeling

In order to model half-hourly electricity demand, the daily electricity demands, as well as intraday electricity demands that consider different building characteristics, are modeled. However, due to data availability, the building characteristics which are used in the electricity demand modeling are different from heat demand modeling. The daily electricity demand modeling and intraday electricity demand modeling are detailed in the following sections.

3.2.2.2.1 Daily electricity demand modeling

The daily electricity demand of different customer sectors for postcode districts $de_{d,c,p}$ is scaled down from the regional level daily electricity consumption $DE_{d,c,r}$, by applying the ratio of annual electricity consumption at postcode level $AE_{c,p}$ [115] and annual electricity consumption at a regional level $AE_{c,r}$ [107], using equation (III-4).

$$de_{d,c,p} = \frac{DE_{d,c,r} AE_{c,p}}{AE_{c,r}} \quad (\text{III-4})$$

For all $d \in \mathbf{D}$, $c \in \mathbf{C}$, $p \in \mathbf{P}$.

3.2.2.2.2 Intraday electricity demand modeling

The intraday electricity demand is modeled using a bottom-up approach, which is used to generate the electricity demand with half-hour resolution. The intraday electricity demand starts with modeling individual buildings with different characteristics. Due to the availability of the information, the building categorization is different from heat demand modeling. The individual buildings are categorizing into eight profile classes [116]. More specifically, the domestic customers

are grouped into two classes which consist of, profile class 1 which represents a single traffic customers' class (i.e., customers who pay a constant price for electricity) and profile class 2 which represents an economy 7⁶ customers' class (i.e., customers who pay a lower price for a 7-hour period during the night), while the non-domestic customers are grouped into single traffic customers, economy 7 customers and customers with different peak load. The detail of grouping information is shown in Table III-2 [116]. The typical days are grouped into weekdays, Saturday and Sunday while the seasons are specified into spring, summer, high summer, autumn, and winter. A detailed description is shown in Table III-3 [117].

Table III-2. Description of electricity profile classes [116]

Class	Description
Class 1	Domestic Unrestricted Customers (single rate)
Class 2	Domestic Economy 7 Customers (two rates)
Class 3	Non-Domestic Unrestricted Customers (single rate)
Class 4	Non-Domestic Non-Maximum Demand Economy 7 Customers (two rates)
Class 5	Non-Domestic Maximum Demand ⁷ Customers with Peak Load Factor ⁸ 0-20%
Class 6	Non-Domestic Maximum Demand Customers with Peak Load Factor 20-30%
Class 7	Non-Domestic Maximum Demand Customers with Peak Load Factor 30-40%
Class 8	Non-Domestic Maximum Demand Customers with Peak Load Factor >40%

Table III-3. Description of typical seasons [117]

Season	Description
--------	-------------

⁶ "Economy 7" tariff refers to a differential tariff which consumers pay less for electricity during 7 off-peak hours during the night. The off-peak hours vary between regions, seasons, and retailers.

⁷ "Maximum Demand Customers" refers to the customers that have a meter which has a register that gives the maximum demand for a given period [116]

⁸ "Peak Load Factor" refers to the ratio of the total electricity consumption (in kWh) during a given period to the number of kWh that could have applied if the maximum demand is maintained throughout this period [116].

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	Defined as the period from the day of clock change from Greenwich Mean Time to
<i>Spring</i>	British Summer Time in March, up to and including the Friday preceding the start of the summer period
<i>Summer</i>	Defined as the ten-week period, preceding high summer, starting on the sixteenth Saturday before the August Bank Holiday
<i>High Summer</i>	Defined as the period of six weeks from the sixth Saturday before August Bank Holiday to the Sunday following August Bank Holiday
<i>Autumn</i>	Defined as the period from the Monday following the August Bank Holiday, up to and including the day preceding the clock change from British Summer Time to Greenwich Mean Time in October
<i>Winter</i>	Defined as the period from the day of clock change from British Summer Time to Greenwich Mean Time in October, up to the day preceding the clock change from Greenwich Mean Time to British Summer Time in March

Figure III-5 shows the normalized half-hourly intraday electricity demand profiles for eight profile classes on A) typical winter weekdays, and B) typical winter Saturdays, which are based on [118]. It can be seen that the residential customers (i.e., profile class 1 and profile class 2) have different load profiles compared to the non-domestic customers (i.e., profile class 3 to 8). More specifically, the electricity demand for domestic customers is concentrated during the night when customers are at home, i.e., between 16.00h to 8.00h, while for non-domestic customers the electricity demand is concentrated during the day, i.e., between 8.00h to 16.00h. Moreover, for profile class 1, which is under a single electricity tariff, the peak of electricity demand happens at 19.00h. On the contrary, for profile class 2 which is under an economy 7 tariff, the more electricity is consumed during the off-peak period, with the peak of the electricity demand happens around 1.00h.

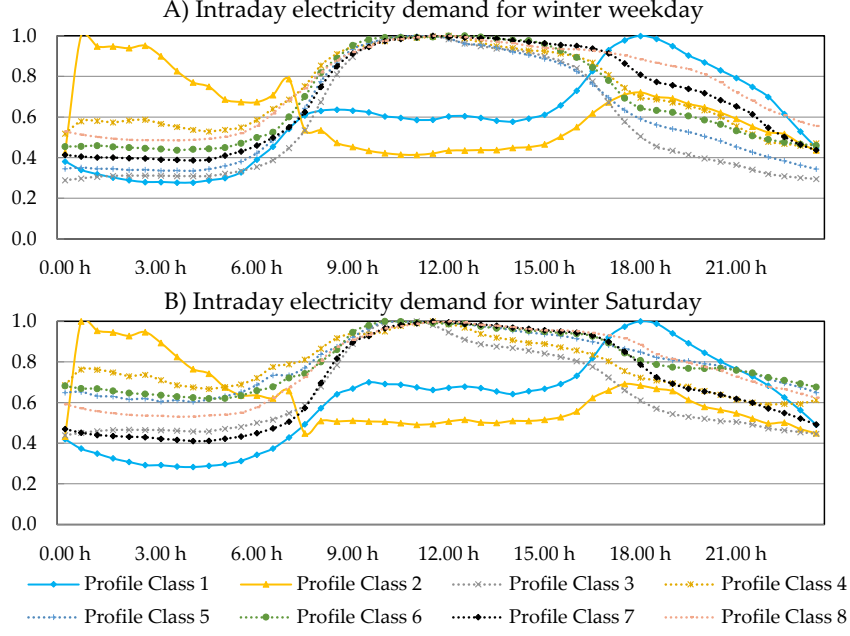


Figure III-5. Normalized intraday electricity demand for eight profile classes on A) typical winter weekday, and B) typical winter Saturday [105]

The intraday electricity demand at the postcode level is based on the customer data extracting from the customers that the electrical distribution substations are connected. The postcode level intraday electricity demand $E_{t,c,p}$ is the aggregations of the collections of different customers' intraday electricity profiles based on their geographical reference (see equation (III-5)). The half-hourly electricity demand for different customer sectors $e_{t,c,p}$ at the postcode level can be scaled down from the daily electricity demand $de_{d,c,p}$ (see equation (III-4)) using (III-6).

$$E_{t,c,p} = N_{c,p} E_{t,c} \quad (\text{III-5})$$

$$e_{t,c,p} = \frac{de_{d,c,p} E_{t,c,p}}{\sum_{t \in \mathbf{T}} E_{t,c,p} \Delta t} \quad (\text{III-6})$$

For all $t \in \mathbf{T}$, $d \in \mathbf{D}$.

3.2.2.3 GIS-based energy demand model

In order to evaluate the spatial distribution of the energy demand, the GIS-based energy demand, which is able to visualize the electricity and heat demand by postcode districts, is developed, based on the geo-referenced resources database and the heat and electricity demand that is obtained using the model presented in section 3.2.2.1 and section 3.2.2.2. To create the GIS-based energy demand model, a sub-regional map by postcode districts is firstly built by extracting the geographical information from the database. The electricity and heat demand is then mapped to its corresponding postcode district. The output of the GIS-based energy demand model includes the energy consumption maps for heat and electricity.

3.2.3 Operational model

The city-level multi-energy system operational model is developed based on a simulation model EnergyPLAN [119]. EnergyPLAN is an advanced energy system analysis computer model [119] which aims to analyze the multi-energy system performance with a sufficient level of details of various energy strategies. It is a deterministic input/output model [120] which optimizes the operation of the energy system under a defined strategy. By defining the input data which includes energy demand time series in different sectors (i.e., electricity, heat and transport), and generation capacities and efficiencies of energy conversion units, the given energy system can be optimized using different regulations, i.e., technical regulation and market-economic regulation. In terms of technical analysis, the model solves the imbalances between energy demands, energy production, energy storage, and en-

ergy exchanges, to maximize the use of available RES and minimize the fuel consumption and import/export [119]. When running an economic analysis, EnergyPLAN seeks to find the solution with the least costs. The outputs generated by EnergyPLAN consist of detailed energy productions, fuel consumption, and CO₂ emissions for a one-year simulation with a one-hour resolution. The model is detail introduced and presented in [119], [121].

As EnergyPLAN considers most of the relevant technologies that can be applied to MES planning [122], it has been broadly used in investigating new operating strategies and investments in flexibility to utilize fluctuating RES (i.e., wind power) and avoid critical exceed electricity production (CEEP) [120]. Meanwhile, it has been applied at different geographic scales. More specifically, EnergyPLAN has been used in local-level analyses, such as the south-west region of Ireland [123] and Aalborg in Denmark [124]–[126], in country or state level, such as Britain [127]–[129], or above state level, such as EU [130] and 10 US states [131].

EnergyPLAN is a deterministic input/output simulation tool that takes into account a broad range of technologies including RES-based power generation units (e.g., onshore and offshore wind power, wave power, tidal, PV, hydropower), RES-based heating units (e.g., geothermal), energy conversion technologies (e.g., fuel boilers, electric boilers, EHP, CHP units, condensing mode power plants, electrolyzer, and synthetic fuel products), and energy storage technologies (e.g., heat storage, CAES, electric vehicles, and hydrogen storage). On this basis, three main energy sectors are considered in the platform: electricity, heat, and transport. The

structure of the EnergyPLAN simulation tool is illustrated in Figure III-6 [132], including the inputs that are required and the output that is gathered from EnergyPLAN.

The input data, which consists of time series energy demand and production for different sectors, the generation capacities and efficiencies for various technologies, and different technical analysis strategies, are elaborated below.

- **Energy demand data**, which is defined as annual consumption. The energy demand data includes annual electricity demand, cooling demand, district heating demand, fuel demands for industry and transport sectors.
- **Energy production units and resources data**, which includes the technical parameters for various generation technologies such as conventional power plant, CHP and RES (e.g., wind power, PV, solar thermal, geothermal, hydropower and wave power), and energy conversion technologies such as electrolyzer, biomass, and gasification plant.
- **Storage data**, which specifies the technical parameters for heat storage, electricity storage, hydrogen storage, and CAES.
- **Fuel costs input data**, which are composed of the fuel types and their emission factors, CO₂ costs, and fuel prices.
- **Cost data**, which includes operational costs and investment costs for various technologies, fuel costs, electricity import/export prices, CO₂ costs, and the interest rate.
- **Simulation strategy**, which defines the simulation and operation of the technologies and the system. The simulation strategies consist of technical simulation, which seeks to find out the energy solution with the lowest fuel consumption and lowest import/export electricity, and market-economic simulation which aims to find the solution with the lowest costs for the system.

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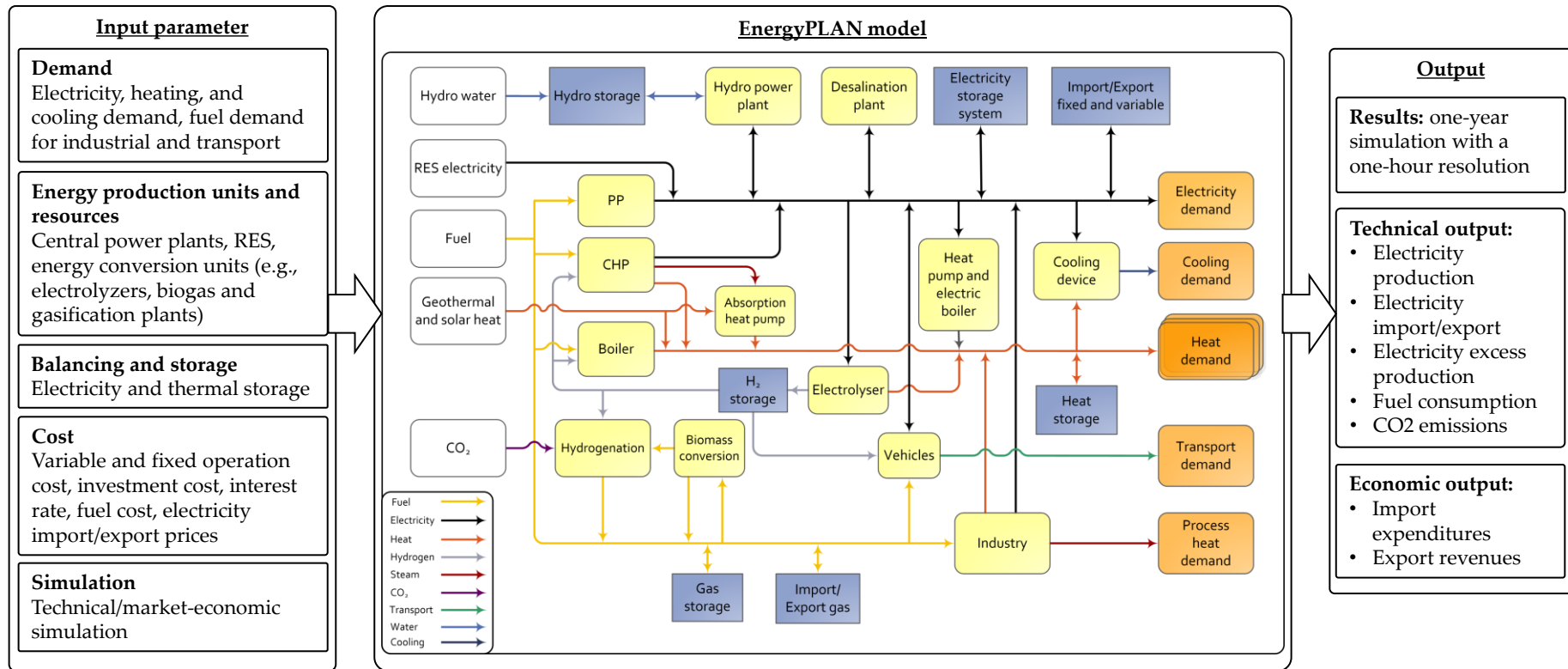


Figure III-6. Structure of EnergyPLAN [132]

A detailed procedure of EnergyPLAN energy system analysis is illustrated in Figure III-7. After all required inputs are typed by the user, some simple calculations, which include the electricity production from RES (e.g., onshore wind, offshore wind, tidal, wave, etc.) and inflexible generation plants (i.e., nuclear power), electricity demand, individual heat demand from boilers, micro CHPs, solar thermal and heat pumps, are firstly calculated (Figure III-7 Step 1).

Then, without involving electricity balance, some initial results are calculated (Figure III-7 Step 2). More specifically, those initial calculations consist of the fixed exchanges with external electricity markets defined by the users, district heating demand, heat and electricity production from industrial and waste, and boiler production in the district heating system.

The next step is divided into two optimization regulations, i.e., technical energy system optimization (Figure III-7 Step 3A) or market-economic energy system optimization (Figure III-7 Step 3B). The system operation is then optimized under different objectives. The technical energy system optimization seeks to minimize the import/export of electricity and fuel consumption. The market-economic energy system optimization focuses on finding the least-cost solution, by economically dispatch the generation technologies based on their operational costs.

Finally, the critical exceed electricity production (CEEP), fuel consumption, CO₂ emissions, and the costs are estimated based on the system operation that is obtained from step 3 (Figure III-7 Step 4).

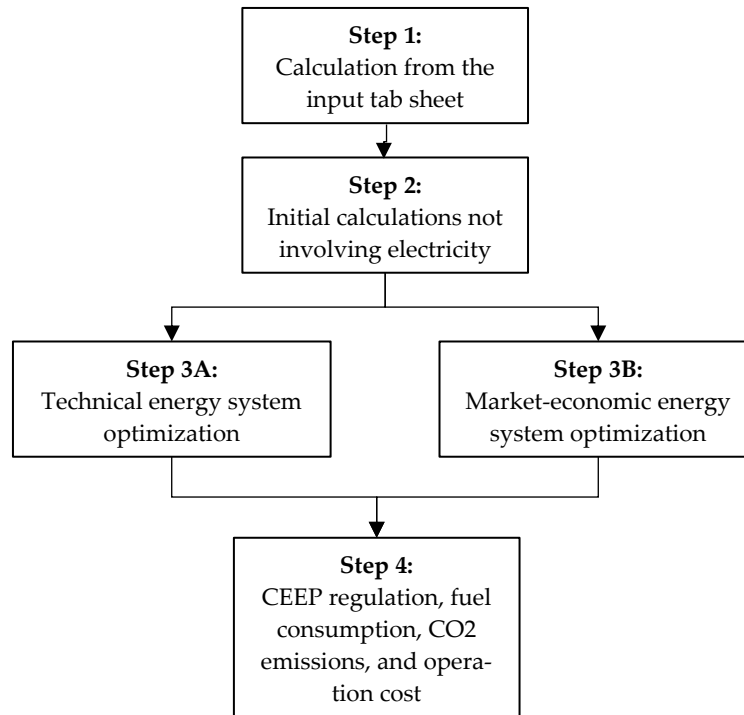


Figure III-7. Flow chart of calculation steps in EnergyPLAN

The results generated from EnergyPLAN show one-year simulations with one-hour resolutions for various units. The technical results consist of electricity production, electricity import/export, electricity excess production, fuel consumption, and CO₂ emissions, while the economic results consist of import expenditures and export revenues.

3.3 Case study – Greater Manchester

In order to demonstrate the purposed city-level MES modeling framework, Greater Manchester is applied as a case study. In this section, an overview of Greater Manchester is firstly presented, followed by the simulation results and discussions.

3.3.1 Overview of Greater Manchester

3.3.1.1 Geographical information

Greater Manchester is a metropolitan country located in North West England. As a metropolitan country, it consists of ten boroughs: the city of Manchester, Stockport, Tameside, Oldham, Rochdale, Bury, Wigan, city of Salford, Trafford, and Bolton. A boundary map is shown in Figure III-8. Moreover, Greater Manchester also contains 89 postcode districts. Each metropolitan borough contains several postcode zones, and the correspondence is shown in Table III-4.

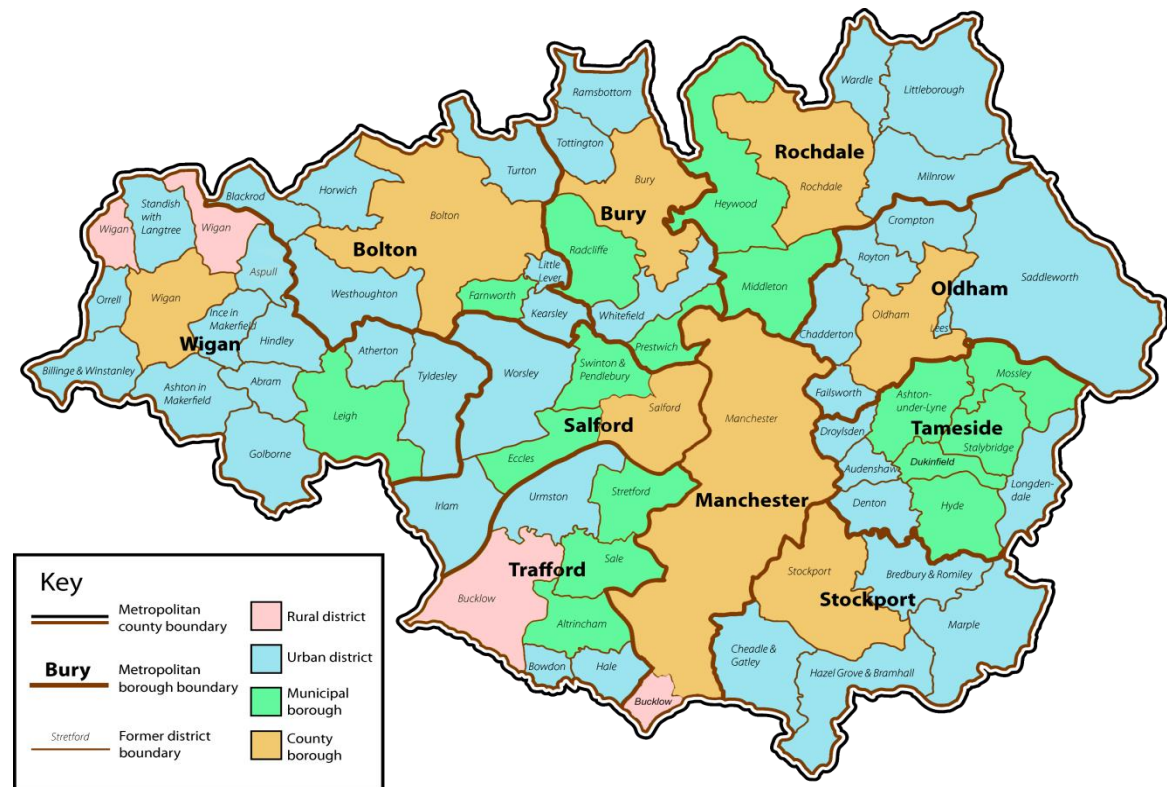


Figure III-8. Greater Manchester boundary map [133]

Table III-4. Boroughs and postcode zones information

Boroughs	Postcode zones
Bolton	BL1, BL2 BL3, BL4, BL5, BL6, BL7, M38
Bury	BL0, BL8, BL9, M25, M26, M45

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Manchester	M11, M12, M13, M14, M15, M18, M19, M20, M21, M22, M23, M1, M2, M4, M8, M9, M40, M90
Oldham	M35, OL1, OL2, OL3, OL4, OL8, OL9
Rochdale	M24, OL10, OL11, OL12, OL15, OL16
Salford	M27, M28, M30, M50, M3, M44, M5, M6, M7
Stockport	SK1, SK2, SK3, SK4, SK5, SK6, SK7, SK8
Tameside	M34, M43, OL5, OL6, OL7, SK14, SK15, SK16
Trafford	M16, M17, M31, M32, M33, M41, WA13, WA14, WA15
Wigan	M29, M46, WA3, WN1, WN6, WN2, WN3, WN4, WN5, WN7

3.3.1.2 Historical energy consumption

With regard to energy consumption, Greater Manchester is mainly supplied by gas, electricity, and petroleum products [134]. Figure III-9 shows the final energy consumption against CO₂ emissions from the year 2005 to the year 2012, which are obtained from [117]. It can be seen that the total energy consumption is highly positively correlated to CO₂ emissions. Moreover, natural gas contributed to 46% of the primary energy consumption, as the heating demand is mainly supplied by natural gas. From 2005 to 2012, the natural gas demand experienced a 22% decrease in domestic and commercial sectors [135] as a result of the improvement of the household insulation and the mild winters that Greater Manchester has experienced. In terms of electricity, energy consumption has fluctuated with a slow decreasing from the year 2005 to the year 2012. More specifically, 16% of the total electricity consumption has been reduced, most of which comes from commercial and industrial sectors while the domestic demands remain stable. Overall the total final energy consumption has experienced a reduction which brought out 18% of the decrease in carbon emissions comparing 2012 with 2015, with some fluctuations.

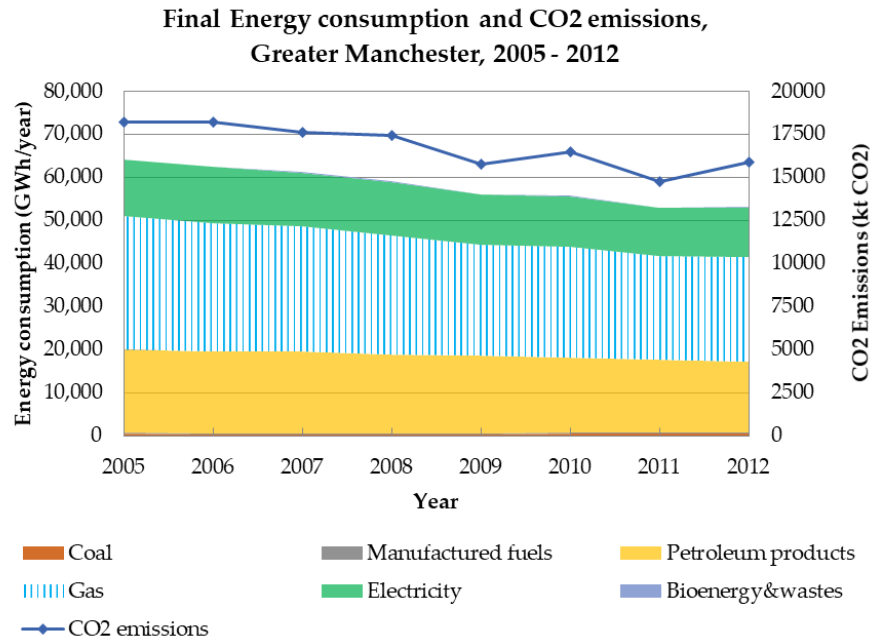


Figure III-9. Greater Manchester historical energy consumption and CO₂ emissions, 2005 to 2012 [105]

3.3.2 Results

3.3.2.1 Heat and electricity demand time series

The Greater Manchester aggregated intraday half-hourly heat demand profiles for typical days and seasons are shown in Figure III-10. In terms of weekdays (see Figure III-10.A), for both winter and midseason, the heat demand is mainly from space heating. The intraday heat demand experience two peaks. The first peak happens around 7.00h, which corresponds to the morning wake up time. The evening peak occurs at 18.00h, corresponding to the evening return time. On the contrary, during the summer season, the heat demand mainly comes from domestic hot water demand which leads to different heat demand profiles than winter and midseason. Instead of having two peaks, the heat demand gradually increases throughout the day and reaches its peak at evening return time, i.e., 18.00h.

Minor differences can be observed when comparing weekend heat demand profiles (Figure III-10.B) with weekday heat demand profiles (Figure III-10.A). For winter and midseason, the morning peak is shifted from 7.00h to 9.00h, while the evening peak remains around 18.00h. Moreover, during the weekdays, the morning peak is slightly lower than the evening peak, while in the case of the weekend the morning peak is higher than the evening peak. The peak demand occurs at 15.00h, instead of weekday evening return time 18.00h. These differences are mainly due to the changes in the occupancy behaviors from weekdays to weekends.

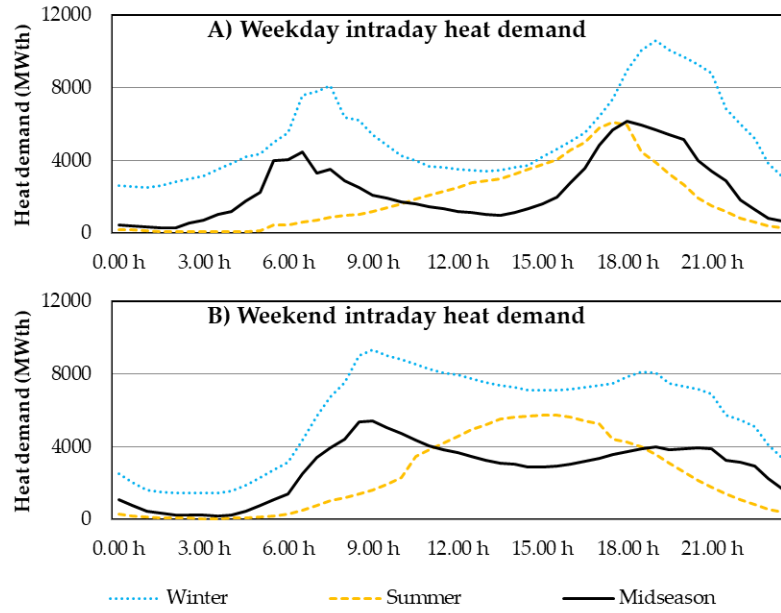


Figure III-10. Greater Manchester aggregated intraday half-hourly heat demand for winter, summer, and midseason on A) weekday, and B) weekend [105]

The Greater Manchester aggregated intraday half-hourly electricity demand profiles for typical days and seasons are shown in Figure III-11. In terms of typical days, i.e., weekdays (see Figure III-11.A), Saturday (see Figure III-11.B), and Sunday (see Figure III-11.C), electricity demand profiles share a similar trend for all

seasons. Two peaks can be observed for all typical days and seasons. For the weekday, the first peak occurs in the morning at 7.00h, while the second peak occurs at evening return time, i.e., 18.00h. The morning peak is shifted to 9.00h on Saturday and is shifted to 12.00h on Sunday, while the evening peak occurs at the same time as on weekdays. It can be noticed that the evening peak is always higher than the morning peak. Moreover, during the winter season, the electricity demand is slightly higher than in other seasons as a result of the electrifications of space heating. Nonetheless, the seasonable fluctuations are not significant as only 10% of the heat demand is supplied by electric heating in Greater Manchester.

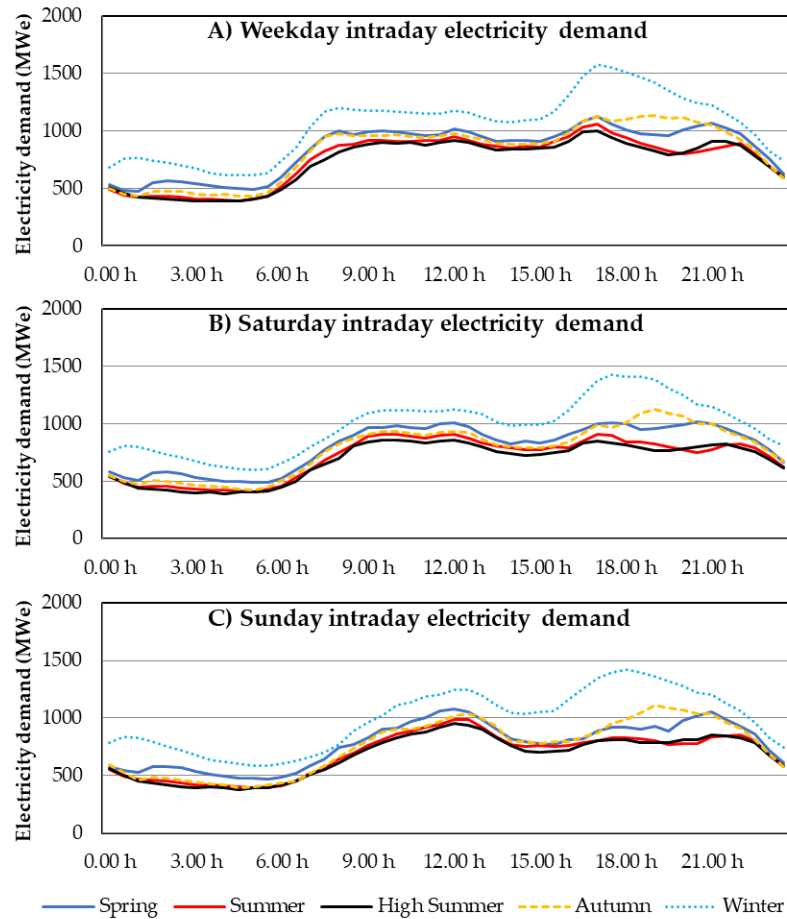


Figure III-11. Greater Manchester aggregated half-hourly intraday electricity demand for spring, summer, high summer, autumn, and winter, on A) weekday, B) Saturday, and C) Sunday [105]

Figure III-12 shows the daily heat and electricity demand for different customer sectors, i.e., domestic customers and non-domestic customers of Greater Manchester, as well as the daily average temperature. As expected, the daily domestic heat demand is highly positively correlated to temperature. Moreover, due to the high penetration of residential households, which require high space heating demand, the domestic heat demand is many times greater than the non-domestic heat demand. On the other hand, the non-domestic heat demand is less positively correlated to the temperature compared to the domestic heat demand.

In terms of electricity demand, domestic electricity demand is much lower than non-domestic electricity demand. Moreover, the electricity demand shows a weaker correspondence with the temperature variation. This is because the heat demand is mainly supplied by gas, while only 10% of the heat demand is met by electricity.

Comparing domestic heat demand (black dash line) and domestic electricity demand (green dash line), it can be observed that during winter and midseason, the domestic heat demand is many times higher than the electricity demand. The results indicate that there is a huge potential to decarbonize the domestic heating sectors. This can be done by replacing old, inefficient gas boilers by other technologies such as EHP and CHP.

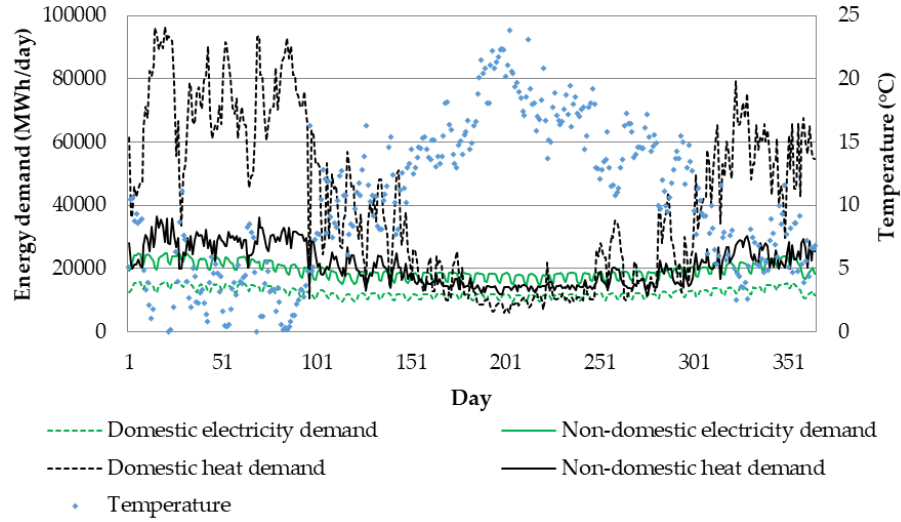


Figure III-12. Greater Manchester aggregated daily heat and electricity demand by customer sectors against the daily average temperature [105]

3.3.2.2 Geo-referenced energy demand map

The energy consumption maps gathered from the GIS-based energy demand model are shown in Figure III-13. The annual heat consumption and annual electricity consumption are presented by consumer sectors, i.e., the domestic sector and non-domestic sector, for 89 postcode districts that are located in Greater Manchester.

In terms of the domestic sector, the electricity demand is positively correlated to the heat demand. That is mainly because both of them are highly dependent on the number and types of residential households. In terms of the non-domestic sector, there is still positive correspondence between electricity demand and heat demand. However, the correlation is not as obvious as it is in the domestic sector.

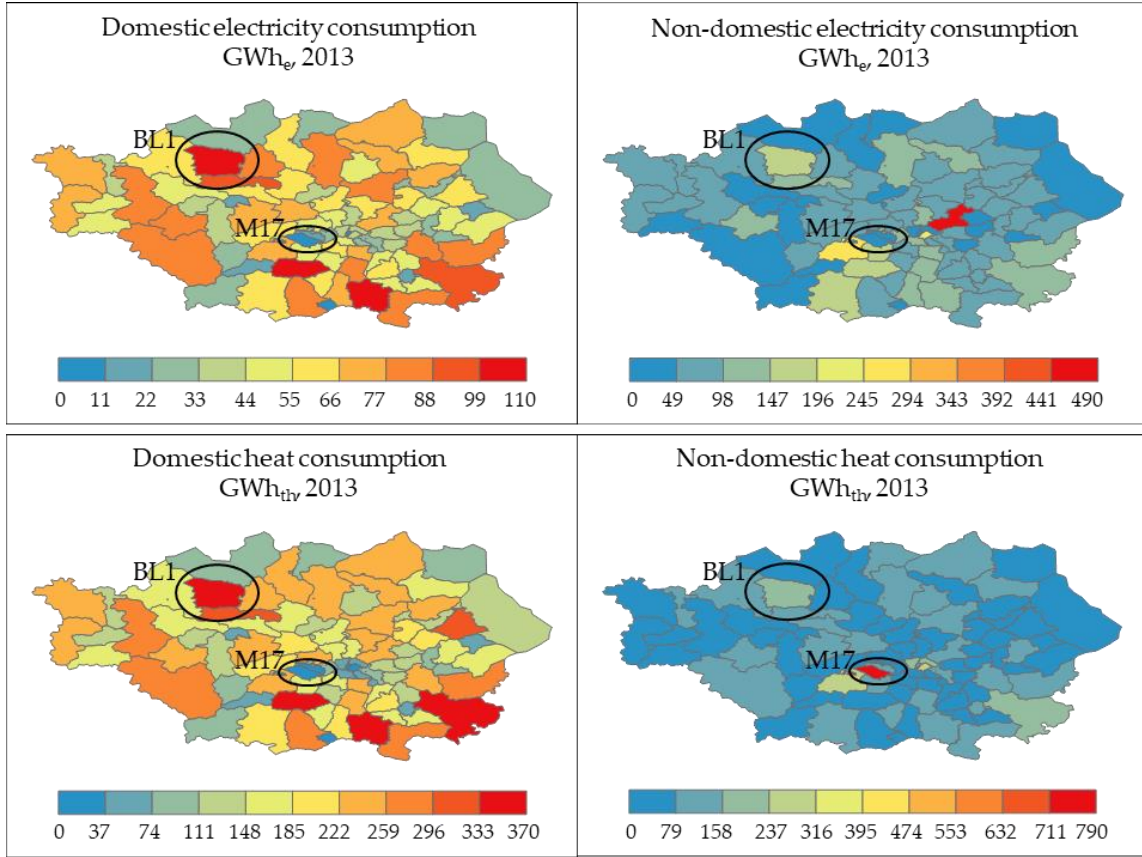


Figure III-13. Greater Manchester annual domestic energy demand (left) and annual non-domestic energy demand (right) by postcode districts. Top: electricity demand; bottom: heat demand [105].

The correlations between heat and electricity sectors are further illustrated through two postcodes, i.e., BL1 and M17, which are circled in Figure III-13. The heat and electricity demand profile for a winter weekday of BL1 (top figures, A1 and A2) and M17 (bottom figures, B1 and B2) are illustrated in Figure III-14. Postcode district BL1 is mainly made of domestic buildings, while postcode district M17 is mainly composed of non-domestic buildings. This can be observed in Figure III-14. A1 and Figure III-14. B1, where most of the heat demand of postcode district BL1 and postcode district M17 come from the domestic sector and non-domestic sector respectively. As a result, postcode district BL1 has the highest do-

mestic heat and electricity consumption, while postcode district M17 has the lowest domestic heat and electricity consumption, as shown in Figure III-13. With regards to the non-domestic sector, postcode district M17 has the highest non-domestic heat consumption among all postcode districts (see Figure III-13 and Figure III-14. B1) whilst its non-domestic electricity consumption is comparably low (see Figure III-13 and Figure III-14. B2). It can be seen that the industrial sector located in postcode district M17 is highly dependent on heat productions rather than electricity.

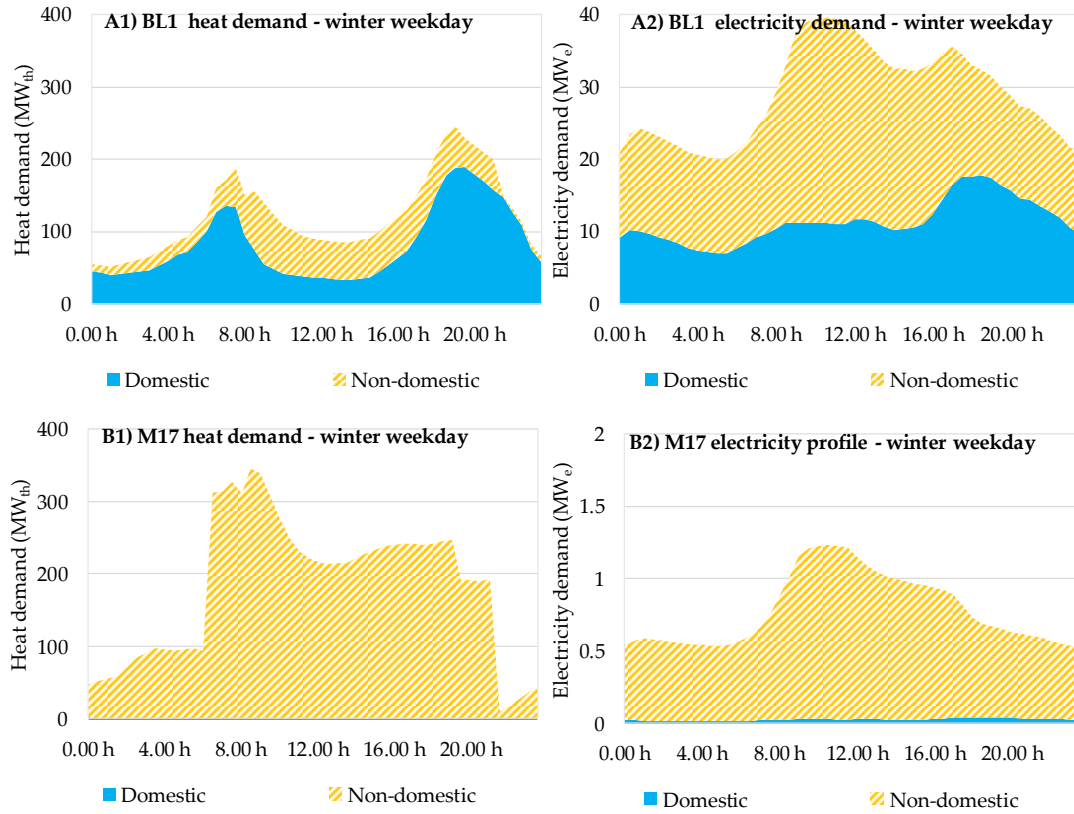


Figure III-14. Heat and electricity demand profiles for A) BL1, and B) M17, on a winter weekday.

The energy consumption map also provides a holistic spatial view of the energy consumption of Greater Manchester, which is the basis of future energy sys-

tem planning. For example, as CHP units can supply both electricity and heat demand at the same time, more benefit of the overall energy system will be achieved by implementing the CHP units in high energy demand local areas.

3.3.2.3 Flexibility analysis

As discussed in the previous section 1.1.3, the electrified heating demand has the potential to provide operational flexibility to the system, by either shifting the demand or substituted using other fuel sources. The proposed energy demand model is able to show the potential flexibility, i.e., the whole feasible operation region that the resources can achieve, as defined in section 1.1.2, that can be extracted, from both temporal and spatial perspectives. Taking postcode area BL1 as an example, Figure III-15 shows the demand flexibility from the heating sector for both domestic and non-domestic buildings. The flexible demand is defined as the electrified heating demand, assuming 5% of the domestic space heating and 10% of the non-domestic space heating are provided by electric heaters.

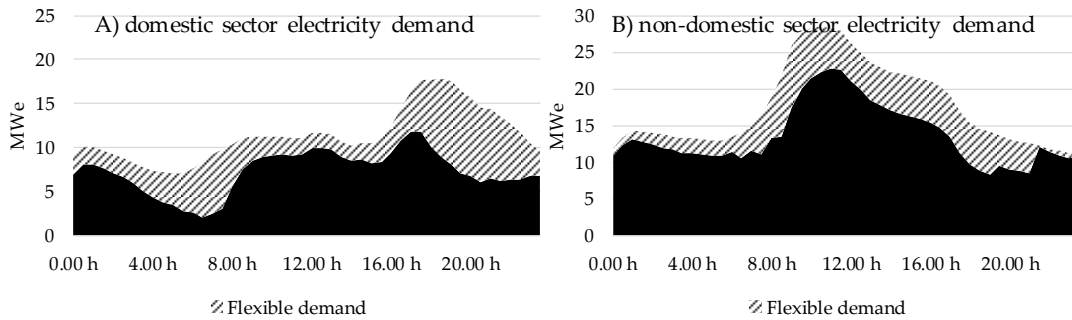


Figure III-15. BL1 electricity demand and flexible demand for A) domestic sector and B) non-domestic sector

A new heat scenario with electrified heating is studied. The air source heat pumps (ASHP) are considered to replace part of the old gas boilers and provide 30% of the space heating in domestic buildings and 30% of the space heating in

non-domestic buildings. The ASHP is chosen to be the primary heating unit, as they are the most common type of EHP, which accounts for 75% of the EHP installed in the U.K. [136]. The ASHP COP is set to 1.7 at 0 °C and 2 at 20°C. The ASHP COP on the presented day together with the corresponding temperature is shown in Figure III-16.

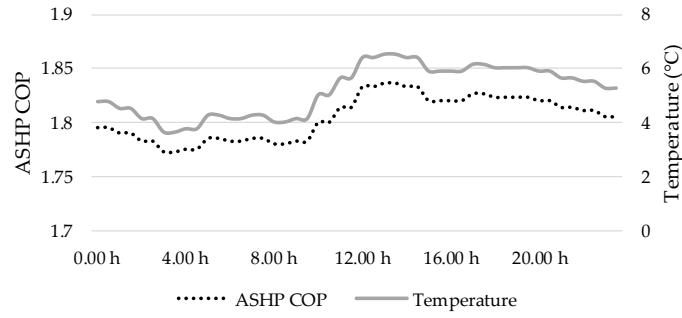


Figure III-16. ASHP COP and outdoor temperature on the presented winter weekday.

The ASHP can provide upward flexibility by lowering its power input. The flexibility potential from ASHP on a winter weekday for the building equipped with ASHP to meet the space heating demand is shown in Figure III-17. It can be seen that the potential upward flexibility from ASHP is in line with the building heat demand (see Figure III-3 and Figure III-4). Specifically, for domestic buildings, the potential flexibility from ASHP experiences two peaks, corresponding to wake up time in the morning, i.e., 7.00h, and return home time in the evening, i.e., 18.00h, while remains low during the day. On the contrary, for the non-domestic sector, higher flexibility potential from ASHP is seen during the day rather than the night.

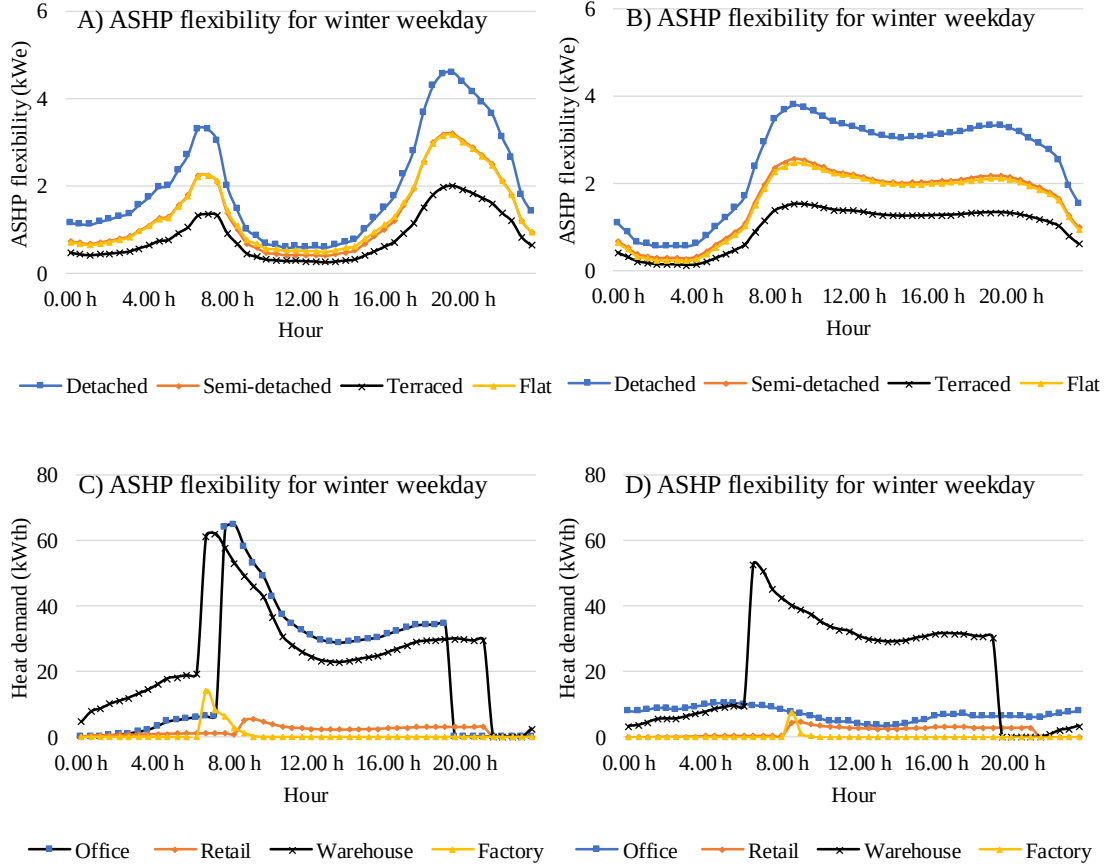


Figure III-17. ASHP flexibility for winter weekday and winter weekend for domestic buildings (top) and non-domestic buildings (bottom)

The aggregated electricity demand profiles for BL1 for both the domestic sector and the non-domestic sector are shown in Figure III-18. It can be seen that by replacing gas boilers with ASHP dramatically increases the peak electricity demand of the postcode area. Similar to the base case scenario without ASHP installation, for the domestic sector, two peaks are experienced at morning wake up time and evening return time, while the demand decreases during the day. However, by replacing gas boilers with ASHP dramatically increases the peak electricity demand of the postcode area. This shows the huge potential of ASHP to provide flexibility to the system. However, how to deploy this flexibility without compromising too much thermal comfort from the consumers' needs to be investigated, which calls for proper optimization tools. On the other hand, the existing distribution

network may struggle to accommodate large penetration of ASHP without any flexibility options or network reinforcement during the morning and evening peak hours. To solve this issue, flexibility options such as coupling ASHP with TES to shift the demand or substituting ASHP with auxiliary gas boilers. The economic flexibility of these options needs to be further investigated, which calls the demand of a comprehensive co-optimization model considering market structures as well as technical characteristics of the technologies while accounting for multi-energy demand as developed in this chapter.

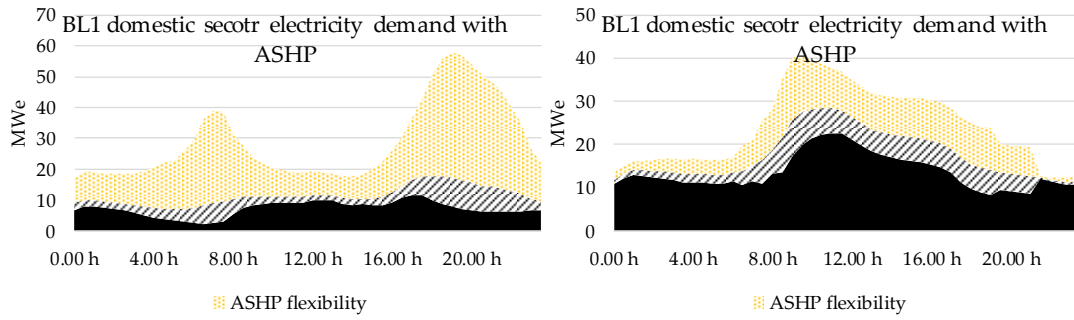


Figure III-18. BL1 electricity demand and flexible demand with ASHP, for A) domestic sector and B) non-domestic sector

3.3.2.4 Techno-economic and environmental performances

In order to assess the techno-economic and economic performance for various heat scenarios, a Greater Manchester energy system model is built using EnergyPLAN. Table III-5 shows the sectoral energy demand (i.e., electricity, residential heating, industrial and transport) for Greater Manchester used in the EnergyPLAN energy system model for technical analysis, which is obtained from [137] [138]. Furthermore, the Greater Manchester aggregated heat demand and electricity demand profiles, which are presented in section 3.3.2.1, are used as the energy demand time series.

Table III-5. Sectoral energy consumption for Greater Manchester

Energy sector		GWh/year
Electricity	Electricity	11847.5
Domestic	Natural gas	16200.0
	Coal	139.1
	Oil	383.9
Industrial	Natural gas	9351.2
	Coal	283.6
	Oil	1615.4
Transportation		15839.1

Four heat scenarios with different portfolios of heating technologies, including CHP, EHP, resistive heating, and gas boilers, have been considered in the analysis in order to decarbonize the heating sector. The scenarios were developed based on [139] and [102]. The heat scenarios are introduced below.

- **Heat scenario 0 (HS0): reference case.** This is a reference case with the same portfolios of heating technologies as today. More specifically, gas boilers and electric heating produce heat for domestic and commercial buildings with a share of 90% and 10% respectively. No heat network exists.
- **Heat scenario 1 (HS1): large-scale CHP installation.** In this case, large-scale CHP units are promoted. The large-scale CHP plants and individual buildings are connected to heat networks. It is assumed that the CHP plants, whose electrical and thermal efficiencies are set to 41% and 46% [140], can provide 35% of the total heat demand. The gas boilers and electric heating are assumed to produce 60% and 5% of the heat demand respectively.
- **Heat scenario 2 (HS2): large-scale CHP and centralized EHP installation.** In HS2 large-scale CHP plants are installed to produce 25% of the

heat demand while centralized water source heat pumps (WSHP) with a COP of 2.2 [141] produce 10% of the heat demand. Both CHP plants and WSHP are connected to heat networks as well as individual buildings. Meanwhile, 60% of heat demand is provided by gas boilers and 5% produced by electric heating.

- **Heat scenario 3 (HS3): decentralized EHP installation.** In this case, decentralized EHP, including air source heat pumps (ASHP) and ground source heat pumps (GSHP), are installed at buildings. 35% of the total heat demand is provided by ASHP and GSHP, where 35% of commercial heating appliances and 65% of domestic heating appliances are ASHP while others are GSHP. The GSHP is assumed to have an average COP of 3.5 throughout the year [142]. The ASHP COP is set to 1.71 at 0 °C and 2.1 at 20 °C. The gas boilers and electric heating contribute 60% and 5% of the heat demand respectively.

The heating scenarios indicated above are then simulated through the city level MES operational model to assess the city level environmental and economic performance. The variation of CO₂ emissions following changes in the CO₂ intensity of the electrical grid is shown in Figure III-19.

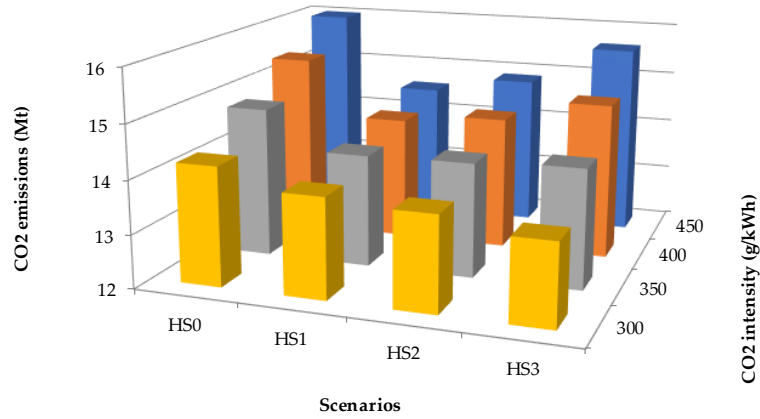


Figure III-19. CO₂ emissions variation with changing in grid CO₂ intensity

As shown in Figure III-19, given by current CO₂ intensity, (i.e., 450g/kWh [143]), HS1 has the lowest CO₂ emissions followed by HS2 and HS3, while HS0 has the lowest CO₂ emissions. The differences in CO₂ emissions are due to different portfolios of CHP and EHP that each scenario has, i.e., HS1 has the highest CHP penetration level, while HS3 has the highest EHP penetration level. The integration of CHP provides the system with both electricity and heat with high overall efficiency compared to traditional coal and natural gas power plants. Unlike CHP which can produce both heat and electricity, EHP can only produce heat by consuming electricity. Thus, in HS3, the electricity demands are entirely supplied by the electricity generation outside Greater Manchester. With the decrease of the CO₂ intensity due to the decarbonizing of electricity, the overall environmental performance of HS3 becomes better. When the CO₂ intensity reduces to 300 g/kWh, HS3 has the lowest CO₂ emissions followed by HS2, HS1, and HS0.

A general conclusion can be inferred from the above discussion as follows. On the one hand, when the CO₂ intensity of the electricity generation outside the city is high, high penetration of CHP (e.g., HS1) would lead to a better environmental performance of the city's energy system compared with a high penetration of EHP

(e.g. HS3); on the other hand, once the CO₂ intensity becomes lower, for example, attributed to the integration of renewable generation into the electricity generation portfolio outside the city, in order to achieve a better environmental performance of the city's energy system, high penetration of EHP would be preferred thanks to its high efficiency of converting electricity to heat.

When the heat demand is partly provided by CHP without TES, the flexibility is very limited. This is because the CHP is operated in order to meet the heat demand, while the electricity generation is used to meet the electricity demand or to export to the grid. The ability of CHP to alter its operation is minor. When the CHP is coupled with TES, more flexibility is available, as the TES is able to store the heat generation which can be used later. This means that the CHP operation is not fully driven by the consumers' heat demand, and can be operated in a more flexible manner. Similarly, the flexibility is very limited when the heat demand is partly supplied by EHP without the presence of TES, as the EHP is solely operated based on the consumers' heat demand. Using EHP without TES also significantly increases the peak demand, which may create capacity problems without any network reinforcement. When coupling with TES, EHP can provide greater flexibility to the grid by altering its operation time. Compared with HS1 and HS2, more flexibility can be extracted from HS2, i.e., the heat demand is partly supplied by a combination of CHP and EHP. The operation of CHP is no longer only dictated to the consumers' heat demand, as the heat demand can also be provided by EHP. This leads to a more flexible operation of CHP and EHP. This flexibility can be further boosted when coupling with TES.

Further studies include a comprehensive technical and economic analysis of different scenarios. With regards to the technical analysis, a powerful tool considering various technologies and multi-energy demand is desired, so as to optimize the operation of the technologies and further quantify the flexibility of various technology mixes. The economic analysis should consider all the costs and benefits associated with the scenarios, including the capital costs of additional infrastructures such as heat network, CHP, EHP, and TES, and distribution network reinforcement, as well as the operational costs and revenues.

3.4 Summary

This chapter introduces a multi-energy demand model that is able to model heat and electricity demand from both temporal and spatial perspectives, which provides fundamental information for MES analysis. The proposed model considers various types of buildings and diverse occupancy behaviors. A bottom-up approach is used considering detailed physical models of individual buildings, while a top-down validation is applied using the widely available information. Moreover, a city-level MES modeling framework is developed in order to assess the techno-economic and environmental performances for various low carbon future scenarios.

A case study based on Greater Manchester is carried out. The half-hourly heat and electricity demand for postcode districts within the Greater Manchester area are modeled. Moreover, the flexibility potentials, i.e., whole feasible operation region from the resources, from electrified heating are demonstrated. In order to deploy the flexibility potential, proper optimization model framework is desired to

Chapter III. Multi-energy demand model

balance among the flexibility deployment, economic benefits, and consumers' thermal comfort, while considering market structures and technologies characteristics. Such a model is developed and introduced in Chapter IV.

Chapter IV. Distributed multi-energy system operation model

This Chapter presents the DMES operation model, which aims to capture the value of the flexibility that can be extracted from DMES. The proposed model adopts MILP technique, which is able to optimize the operation of the device, market participation, and grid service provision, while considering all the potential revenue streams that are available for DMES and technical constraints of the devices with appropriate time resolution. The model is demonstrated with three realistic case studies in the context of the NEM.

4.1 Introduction

The potential of aggregation concepts participating in the energy market has been discussed in the literature [55], [56], [65]–[68], [57]–[64]. Operating DER as a VPP instead of individually leads to more revenues from wholesale electricity markets [55], [66]. Reference [60] proposes a risk-constrained two-stage stochastic modeling for VPP to participate in day-ahead (DA) and real-time (RT) electricity markets, considering the uncertainties in the energy prices and RES generation. Considering both thermal loads and energy storage, reference [60] presents an optimal scheduling model in the DA electricity market. Using conditional value at risk to assess the risk of profit variability, reference [61] presents a transactive energy framework deploying a two-stage optimization problem to maximize the profit in the DA and RT electricity markets. References [63] propose an optimal bidding model for a commercial VPP participating in the DA market, considering the uncertainties in the RES, load, and energy prices, using a stochastic, bilevel

approach, similar to [144]. Moreover, In reference [65], a bidding strategy for VPP to participate in the electricity market is proposed, while a dispatch model for multiple VPP using game theory is deployed. All the above-mentioned work mainly focuses on electricity market participation (i.e., DA and RT), where the possibility and profitability of participating in other markets are ignored.

A few studies consider both electricity and frequency control market participation, such as [69]–[73]. A price-based unit commitment model for VPP to participate in both the energy and spinning reserve market is developed in [69]. A two-stage stochastic risk-averse optimal offering model is proposed in [70], in order to assess the profitability of VPP participating in DA and RT electricity markets and spinning reserve markets. Reference [71] presents an offering model aims to maximize the expected profit of a VPP participating in both the DA electricity market and the balancing market. The authors in [72] propose an energy and ancillary services co-optimization model covering multiple energy sectors such as electricity and thermal load. An energy/reserve co-optimization model considering an RT electricity market and various FCAS with different timescales are presented in [145].

DR market is also a potential market for DER and consumers to boost economic benefits. By intentionally changing electricity consumption profiles in response to some kind of price signals or incentives [95], [146], flexible demand-side resources can help grid operators to manage electricity supply and demand during extreme peaks through DR programs. In [74], a DR model for an aggregator with flexible demand and RES participating in both wholesale electricity markets and DR programs is presented. A stochastic model considering both the electricity market

and the DR exchange market is proposed in [75]. The authors of [75] also conclude that engaging DR market mechanisms have the potential to increase the economic benefits, particularly by minimizing the energy imbalance costs caused by the uncertainties in variable resources and loads. A multi-stage stochastic model is proposed in [76], where the author defined three potential markets, i.e., a DA electricity market, an RT electricity market, and an option market for long-term reserve.

Furthermore, by employing generation capacity, the flexible demand-side resources are also able to provide hedging products for retailers to hedge the risk of facing extremely high wholesale electricity prices [147]. By providing the hedging products, extra revenue streams are available for the consumers and the aggregators. However, such a market has not been assessed in the literature.

Providing reliability services to DNSP is another potential grid service that can be provided specially by grid-connected microgrids, as discussed in Chapter II section 2.2.5. However, as the value of the reliability services is not well defined, the potential of grid-connected microgrids contributing to distribution network reliability is often underestimated. Microgrids providing reliability to internal consumers is investigated in [148], while microgrids providing reliability to the local distribution network is studied in [51]. However, those works do not consider the potential revenue streams from providing such services. A framework of integrating relevant price signals of reliability services is proposed in [42], [43]. However, the framework is specific to the context of the UK, which is not applicable for Australia, while the modeling of common technologies such as CHP, EHP, and TES is not considered.

The appropriate temporal resolution also plays an important role when assessing the techno-economic performance of a district [149]. Finer time resolutions are often preferred when modeling residential buildings with volatile demands, as the averaging effects of coarse temporal precision can lead to inaccurate results [149]. When choosing the time resolution, besides the available information such as energy prices, environment, and demand data, the abovementioned metrics should also be considered. In order to properly quantify the value of flexibility, the modeling resolution should be in line with the market operation.

In the context of the above, a DMES operation model is developed, in order to capture the value of the flexibility that can be extracted from DMES. The proposed model considers all potential revenue streams and technical constraints of technologies with appropriate time-resolutions which are in line with the market structures in the context of NEM. Specifically, the proposed model optimizes the participation in simultaneous multiple markets and the provision of multiple grid services, under various objectives. In the rest of this chapter, the model formulation of the DMES operation model, which draws from the publication [21], [41], [73], [77], [145], is presented in section 4.2. Moreover, section 4.3 details three case studies so as to demonstrate the model. Lastly, section 4.4 concludes and summarizes this chapter.

4.2 Modeling framework

This section presents the DMES operation model, which is a multi-market multi-service co-optimization model for DMES⁹. This model uses a mixed-integer

⁹ The definition of the parameters and variables can be found in Notations.

linear programming (MILP) technique, aiming to optimize the technologies' operation set points, multi-market participation, and multi-service provision at each time step, under various objectives. The formulations are generally applicable for various multi-energy resources, such as DG, energy storage, heating and cooling appliances, as well as buildings. The price signal from different markets is applied at the appropriate aggregation level, so as to enable to co-optimization of multi-market participation and grid service provision.

4.2.1 Objective function

The model may be optimized with regards to various objectives based on different operating strategies, such as energy minimization, electricity independence, and cost minimization.

Under an energy minimization objective, i.e., expression (IV-1), the technologies are operated in a way to minimize the overall energy consumption. More specifically, the use of heating and cooling appliance is minimized without compromising the thermal comfort of the internal users. The use of the BESS and electrolyzer is also limited so that to avoid energy losses.

$$Obj_{EM} = \min \left\{ \sum_{t \in T} \left[\sum_{l \in L} \sum_{a \in A} \left(\frac{pc_{t,l,a}^{app}}{\rho c_a^{app}} + \frac{ph_{t,l,a}^{app}}{\rho h_a^{app}} \right) + \sum_{b \in B} \frac{p_{t,b}^{bes-}}{\rho_b^{bes}} + \sum_{h \in H} p_{t,h}^{hp} \right] \right\} \quad (IV-1)$$

The electricity independence object aims to reduce the interactions with the grid and so as to achieve electricity self-sufficiency, i.e., minimize the electricity import from the grid and electricity export to the grid over the scheduling horizon, as shown in expression (IV-2).

$$Obj_{EI} = \min \left\{ \sum_{t \in \mathbf{T}} (p_t^- + p_t^+) \right\} \quad (\text{IV-2})$$

The cost minimization objective is used to minimize the net cost, which is defined as the operational costs substitute revenues, as described in expression (IV-3). The operational costs are represented by the first, second, and eighth term, which include the cost of importing electricity and fuels (first and eighth term), and operational cost of technologies (second term). The revenues are represented by the third, fourth, fifth, sixth, and seventh term. Those include the revenues from different market participation, i.e., electricity market (third term), FCAS market (fourth term), DR market (fifth term), and hedging contract market (sixth term), and providing reliability services (eighth term).

$$\begin{aligned}
 Obj_{CM} = \min & \left\{ \sum_{t \in \mathbf{T}} \left[\overbrace{p_t^- \lambda_t^{elec-} \Delta t + \sum_{f \in \mathbf{F}} (e_{t,f}^- \lambda_{t,f}^{fuel-})}^{\text{first term}} \right. \right. \\
 & + \overbrace{\sum_{g \in \mathbf{G}} (p_{t,g}^{gen} \gamma_g^{gen} \Delta t + u_{t,g}^{SU} \gamma_g^{SU} + u_{t,g}^{SD} \gamma_g^{SD})}^{\text{second term}} \\
 & - \left(\overbrace{p_t^+ \lambda_t^{elec+} \Delta t + \sum_{f \in \mathbf{F}} (e_{t,f}^+ \lambda_{t,f}^{fuel+})}^{\text{third term}} \right) \\
 & - \left[\overbrace{\sum_{\chi \in \mathbf{X}} (p_{t,\chi}^r \lambda_{t,\chi}^r + p_{t,\chi}^l \lambda_{t,\chi}^l) \Delta t}^{\text{fourth term}} - \overbrace{p_t^{cap} \lambda^{cap} \Delta t}^{\text{fifth term}} - \overbrace{\sum_{v \in \mathbf{Y}} p_{t,v}^{rel} \lambda_{t,v}^{rel} \Delta t}^{\text{sixth term}} \right. \\
 & \left. \left. - \overbrace{p^{DR} \cdot \lambda^{DR} \Delta t}^{\text{eventh term}} + \overbrace{\bar{p}^{GCP} \lambda^{peak}}^{\text{eighth term}} \right] \right\} \quad (\text{IV-3})
 \end{aligned}$$

4.2.2 Technology operational constraints

This section presents the operational constraints for different technologies, consisting of the generator, RES, heating and cooling appliance, energy storage, and the electrolyzer.

The optimization is based on physical modeling of energy converters (e.g., generator, RES, electrolyzer, and heating and cooling appliance) and energy storage (e.g., BESS, fuel storage, and TES). An example of the illustration of the modeling of various technologies can be found in Figure IV-1. The energy converters are modeled using efficiency factors which are applied to the input energy (e.g., electricity, and gas) to produce one or more types of output energy (e.g., electricity, hydrogen, heating, and cooling). Different parameters are used to model energy storage depending on the type of energy that is stored and the characteristics of the energy storage. For instance, a round trip efficiency is applied to the BESS in order to model the electricity losses in the BESS charging and discharging process. Whereas, for the TES, thermal resistances and thermal capacitances are used in order to model the energy losses from the TES to the environment, taking into consideration the temperature of the TES and the temperature of the environment.

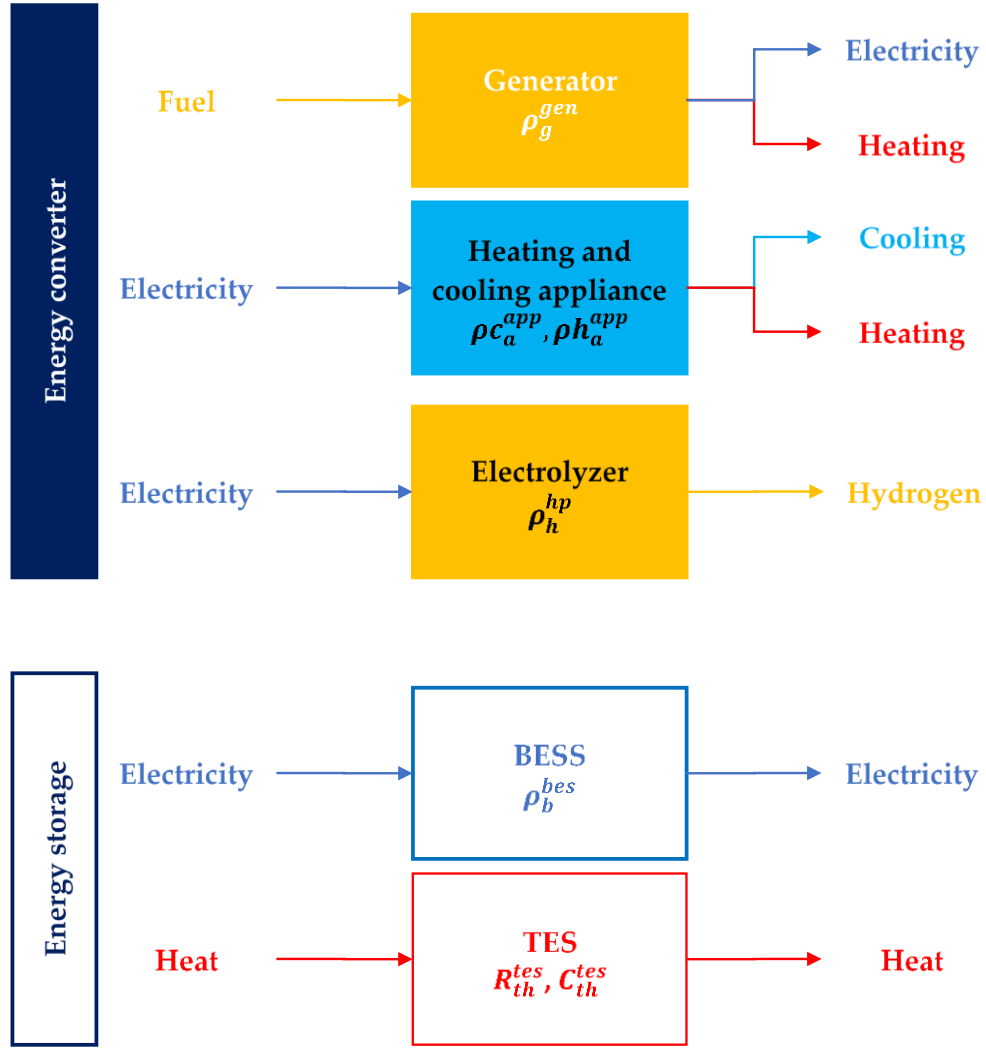


Figure IV-1. Example of energy converter and storage modeling

4.2.2.1 Generator

Constraints (IV-4)-(IV-5) set the operating limits for the generator. The binary indicator, $u_{t,g}^{on}$, is set to be one when the generator is online, which is to make sure that the generator can only be operated between its minimum power output $\underline{P}_g^{gen}$ and maximum power output $\overline{P}_g^{gen}$. Moreover, binary variables, $u_{t,g}^{SU}$ and $u_{t,g}^{SD}$ are introduced, in order to model the start-up and shut-down costs of the generator.

$$u_{t,g}^{on} \underline{P}_g^{gen} \leq p_{t,g}^{gen} \leq u_{t,g}^{on} \overline{P}_g^{gen} \quad (IV-4)$$

$$u_{t,g}^{on} - u_{t-1,g}^{on} = u_{t,g}^{SU} - u_{t,g}^{SD} \quad (IV-5)$$

For all $t \in \mathbf{T}$, $g \in \mathbf{G}$.

4.2.2.2 Renewable energy resources

The operation of the RES is constrained by (IV-6). The RES output power $p_{t,r}^{res}$ and curtailment $p_{t,r}^{curt}$ are limited by the time-varying maximum power output $P_{t,r}^{res}$, which is determined by the available resources at each time step, such as the solar irradiation or wind speed. Constraint (IV-6) enables the RES to be operated under a curtail mode, by introducing the variable $p_{t,r}^{curt}$, which allows the RES to use its headroom to participate in raise FCAS and FFR.

$$p_{t,r}^{res} + p_{t,r}^{curt} \leq P_{t,r}^{res} \quad (IV-6)$$

For all $t \in \mathbf{T}$, $r \in \mathbf{R}$.

4.2.2.3 Heating and cooling appliance

Constraints (IV-7)-(IV-10) set the operation limits of various heating and cooling appliances, such as EHP, electric boiler, and electric heater. Constraints (IV-7) and (IV-8) ensure that the devices are operated within their minimum and maximum power limits. Constraints (IV-9) and (IV-10) make sure that the appliances do not provide heating and cooling at the same time, by introducing the binary variable $u_{t,l,a}^{app}$.

$$\underline{P}h_{l,a}^{app} \leq ph_{t,l,a}^{app} \leq \overline{P}h_{l,a}^{app} \quad (IV-7)$$

$$\underline{P}c_{l,a}^{app} \leq pc_{t,l,a}^{app} \leq \overline{P}c_{l,a}^{app} \quad (IV-8)$$

$$ph_{t,l,a}^{app} \leq \overline{Ph}_{l,a}^{app} u_{t,l,a}^{app} \quad (\text{IV-9})$$

$$pc_{t,l,a}^{app} \leq \overline{Pc}_{l,a}^{app} (1 - u_{t,l,a}^{app}) \quad (\text{IV-10})$$

For all $t \in \mathbf{T}$, $a \in \mathbf{A}$, $l \in \mathbf{L}$.

4.2.2.4 Electrolyzer

The operation of the electrolyzer is limited using constraints (IV-11)-(IV-12). The electrolyzer operation power is limited by its maximum power input and minimum power input when it is online, i.e., $u_{t,h}^{on} = 1$ (see constraint (IV-11)). Binary variable $u_{t,h}^{SU}$ and $u_{t,h}^{SD}$ are introduced to model the start-up and shut-down behavior of the electrolyzer.

$$u_{t,h}^{on} \underline{P}_h^{hp} \leq p_{t,h}^{hp} \leq u_{t,h}^{on} \overline{P}_h^{hp} \quad (\text{IV-11})$$

$$u_{t,h}^{on} - u_{t-1,h}^{on} = u_{t,h}^{SU} - u_{t,h}^{SD} \quad (\text{IV-12})$$

For all $t \in \mathbf{T}$, $h \in \mathbf{H}$.

4.2.2.5 Energy storage

Three types of energy storage are considered in the modeled, i.e., BESS, fuel storages, and TES.

4.2.2.5.1 Battery energy storage system

The BESS operation is limited using constraints (IV-13)-(IV-18). More specifically, the intertemporal constraint (IV-13) is set to define the BESS energy level at the next time step, which is determined by the energy level of BESS of current time step $x_{t,b}^{bes}$, charge power $p_{t,b}^{bes-}$, and discharge power $p_{t,b}^{bes+}$ at the current time step.

The BESS energy level is also constrained by its maximum capacity $\bar{X}_b^{bes}$ and minimum capacity $\underline{X}_b^{bes}$, using constraint (IV-14). The BESS charge and discharge power is limited by its minimum and maximum charge and discharge power using (IV-15)-(IV-16). Constraints (IV-17) and (IV-18) are used to make sure that the BESS can either charge or discharge at per time step, by introducing the binary variable $u_{t,b}^{bes}$.

$$x_{t+1,b}^{bes} = x_{t,b}^{bes} + \left(p_{t,b}^{bes-} - \frac{p_{t,b}^{bes+}}{\rho_b^{bes}} \right) \Delta t \quad (\text{IV-13})$$

$$\underline{X}_b^{bes} \leq x_{t,b}^{bes} \leq \bar{X}_b^{bes} \quad (\text{IV-14})$$

$$\underline{P}_b^{bes-} \leq p_{t,b}^{bes-} \leq \bar{P}_b^{bes-} \quad (\text{IV-15})$$

$$\underline{P}_b^{bes+} \leq p_{t,b}^{bes+} \leq \bar{P}_b^{bes+} \quad (\text{IV-16})$$

$$p_{t,b}^{bes+} \leq \bar{P}_b^{bes+} u_{t,b}^{bes} \quad (\text{IV-17})$$

$$p_{t,b}^{bes-} \leq \bar{P}_b^{bes-} (1 - u_{t,b}^{bes}) \quad (\text{IV-18})$$

For all $t \in \mathbf{T}$, $b \in \mathbf{B}$.

4.2.2.5.2 Fuel storage

The fuel storage, including natural gas storage and hydrogen storage, is modeled using constraint (IV-19)- (IV-20). The fuel storage energy level intertemporal constraint is shown in (IV-19), that is, the fuel storage energy level at the next time step depends on the fuel storage energy level at current time-step $x_{t,f}^{fuel}$, fuel generation (for instance, hydrogen generated by the electrolyzer) and consumption

(e.g. through the use of the generator), as well as fuel import $e_{t,f}^-$ and fuel export $e_{t,f}^+$. Parameter $\Phi_{h,f}^{hp}$ and $\Phi_{g,f}^{gen}$ are introduced in order to map the electrolyzer's output to hydrogen while to indicate the generator's input fuel type. The fuel storage energy level is also limited by its minimum/maximum energy level using (IV-20).

$$x_{t+1,f}^{fuel} = x_{t,f}^{fuel} + \sum_h^{N_h} (\Phi_{h,f}^{hp} p_{t,h}^{hp} \rho_h^{hp}) - \sum_g^{N_g} \left(\frac{\Phi_{g,f}^{gen} p_{t,g}^{gen}}{\rho_g^{gen}} \right) + (e_{t,f}^- - e_{t,f}^+) \quad (IV-19)$$

$$\underline{X}_f^{fuel} \leq x_{t,f}^{fuel} \leq \bar{X}_f^{fuel} \quad (IV-20)$$

For all $t \in \mathbf{T}$, $f \in \mathbf{F}$.

4.2.2.5.3 Thermal energy storage

The TES is modeled using constraints (IV-21)-(IV-24). The energy level of the TES at next time step $x_{t+1,th}^{tes}$ is determined by the intertemporal constraint (IV-21), which depends on the current energy level of TES $x_{t,th}^{tes}$, heat energy input $h_{t,th}^{in}$, heat energy output $h_{t,th}^{out}$, as well as the heat losses to the environment $x_{t,th}^{loss}$. The TES energy level is further constrained by its minimum and maximum energy level, which is determined by the TES minimum temperature $\underline{T}_{th}^{tes}$, TES maximum temperature $\bar{T}_{th}^{tes}$, and outdoor temperature T_t^{out} using constraint (IV-22). The heat losses to the environment $x_{t,th}^{loss}$ is modeled using constraint (IV-23). The heat output from TES is used to meet the domestic hot water demand $h_{t,l}^{dhw}$ and the space heating demand of the buildings $h_{t,l}^{sh}$ that are not provided by heating appliances, using (IV-24).

$$x_{t+1,th}^{tes} = x_{t,th}^{tes} + h_{t,th}^{in} - h_{t,th}^{out} - x_{t,th}^{loss} \quad (IV-21)$$

$$(\underline{T}_{th}^{tes} - T_t^{out})C_{th}^{tes} \leq x_{t,th}^{tes} \leq (\bar{T}_{th}^{tes} - T_t^{out})C_{th}^{tes} \quad (IV-22)$$

$$x_{t,th}^{loss} = \frac{\left(\frac{x_{t,th}^{tes}}{C_{th}^{tes}} - T_t^{out}\right)\Delta t}{R_{th}^{tes}} \quad (IV-23)$$

$$\sum_{th \in TH} h_{t,th}^{out} = \sum_{l \in L} \left(h_{t,l}^{dhw} + h_{t,l}^{sh} - \sum_{a \in A} p h_{t,l,a}^{app} \rho h_a^{app} \right) \quad (IV-24)$$

For all $t \in \mathbf{T}$, $th \in TH$.

4.2.3 Building modeling

4.2.3.1 Building system equations

The building temperature is defined by the intertemporal constraint (IV-25). More specifically, the building temperature at the next time step $\tau_{t+1,l}$ depends on the current building temperature $\tau_{t,l}$, the space heating input $h_{t,l}^{sh}$ from heating appliances and TES, space cooling input $h_{t,l}^{sc}$ from cooling appliances, heat losses from building to the outdoor environment $h_{t,l}^{loss}$, metabolic heat gains $H_{t,l}^{met}$, and solar heat gains $H_{t,l}^{sol}$. The heat losses from building to the environment are defined using equation (IV-26).

The metabolic heat gains and solar heat gains can be partially neglected through occupant actions such as opening the window or using the blind. Variable $v_{t,l}^{met}$ allows the metabolic heat gains to be partly neglected during the winter ($W = 1$), while $v_{t,l}^{met}$ is set to be 0 during the summer as the heat gain cannot be vented with a high outdoor temperature (see constraint (IV-27)). The solar heat gain can

also be partly neglected using variable $v_{i,l}^{sol}$, up to the blind exclusion efficiency ρ^{blind} (see constraint (IV-28)).

$$\tau_{t+1,l} = \tau_{t,l} + (h_{t,l}^{sh} - h_{t,l}^{sc} - h_{t,l}^{loss} + (1 - v_{t,l}^{met})H_{t,l}^{met} + (1 - v_{t,l}^{sol})H_{t,l}^{sol})/C_l \quad (\text{IV-25})$$

$$h_{t,l}^{loss} = \frac{(\tau_{t,l} - T_t^{out})\Delta t}{R_l} \quad (\text{IV-26})$$

$$0 \leq v_{t,l}^{met} \leq W \quad (\text{IV-27})$$

$$0 \leq v_{i,l}^{sol} \leq \rho^{blind} \quad (\text{IV-28})$$

For all $t \in \mathbf{T}$, $l \in \mathbf{L}$.

4.2.3.2 Building thermal comfort limit

Constraint (IV-29) is to ensure that the thermal comfort of the occupants is met when the building is occupied, i.e., $O_{t,l}$ is positive. $\overline{\Delta T}_l^{set}$ is introduced to allow the building temperature $\tau_{t,l}$ to be deviated from the set temperature T_l^{set} .

$$O_{t,l}(T_l^{set} - \underline{\Delta T}_l^{set}) \leq O_{t,l}\tau_{t,l} \leq O_{t,l}(T_l^{set} + \overline{\Delta T}_l^{set}) \quad (\text{IV-29})$$

For all $t \in \mathbf{T}$, $l \in \mathbf{L}$.

4.2.4 Electricity import/export balance

The electricity balance is modeled using (IV-30). The electricity import and export at the grid connection point (GCP) level are determined by the electricity consumption for heating and cooling appliances, electricity consumption for operating the electrolyzer, charge, and discharge of the BESS, and electricity generation from the RES and the generator. Binary variable u_t^{elec} is introduced to ensure that

electricity import and export at GCP does not happen at the same time, using constraints (IV-31) and (IV-32).

$$\begin{aligned}
 p_t^- - p_t^+ = & \sum_{l \in \mathbf{L}} \sum_{a \in \mathbf{A}} (ph_{t,l,a}^{app} + pc_{t,l,a}^{app}) + \sum_{h \in \mathbf{H}} p_{t,h}^{hp} + \sum_{b \in \mathbf{B}} (p_{t,b}^{bes-} - p_{t,b}^{bes+} / \rho_b^{bes}) \\
 & - \sum_{r \in \mathbf{R}} p_{t,r}^{res} - \sum_{g \in \mathbf{G}} p_{t,g}^{gen}
 \end{aligned} \tag{IV-30}$$

$$p_t^+ \leq \bar{P}^+ u_t^{elec} \tag{IV-31}$$

$$p_t^- \leq \bar{P}^- (1 - u_t^{elec}) \tag{IV-32}$$

For all $t \in \mathbf{T}$.

4.2.5 Frequency control ancillary services

Six contingency FCAS markets, i.e., fast/slow/delayed raise/lower contingency FCAS markets, are modeled here. The ability of technologies participating in various FCAS markets depends on how fast they can respond to the contingency events and how long they can sustain the services. More specifically, the RES can participate in fast/slow contingency FCAS, however, it is not considered for delayed FCAS as the sustained delivery for a longer period may not be guaranteed. The BESS, electrolyzer, and heating and cooling appliance can participate in all contingency FCAS market. For the generator, the ability to participate in contingency FCAS is technology dependent, as different types of the generator have various ramping rates. This is modeled by introducing binary parameters $e_{\chi,r}^{res}$, $e_{\chi,g}^{gen}$, $e_{\chi,b}^{bes}$, $e_{\chi,h}^{hp}$, and $e_{\chi,a}^{app}$, where 1 represents the technology is considered to participate in the specific market χ , while 0 means that the technology is not considered to provide the service. Furthermore, contingency FCAS calls are not modeled due to

their low call frequencies. Instead, constraints are employed to make sure that the FCAS can be delivered for the required length at every time step.

4.2.5.1 Raise FCAS

The raise FCAS commitments of the RES, generator, BESS, heating and cooling appliance, and electrolyzer are modeled using constraints (IV-33)-(IV-38). More specifically, the RES, generator, and BESS are able to use their headroom to participate in raise FCAS (see constraint (IV-33)-(IV-36)). Constraint (IV-36) ensures that there is enough energy stored in the BESS to deliver the FCAS at any time step against any FCAS calls. On the contrary, the heating and cooling appliance and electrolyzer can provide raise FCAS using their footroom, i.e., by lowering their operation power (see constraints (IV-37) and (IV-38)). Given the short duration assumed for the delivery of the services (i.e., for the length of the FCAS calls, which is usually within 10 minutes [150]), it may be safely assumed that the thermal comfort level of the building will not be significantly compromised owing to building thermal inertia.

$$p_{t,\chi,r}^{r,res} \leq e_{\chi,r}^{res} p_{t,r}^{curt} \quad (IV-33)$$

$$p_{t,\chi,g}^{r,gen} \leq e_{\chi,g}^{gen} (\bar{P}_g^{gen} - p_{t,g}^{gen}) \quad (IV-34)$$

$$p_{t,\chi,b}^{r,bes} \leq e_{\chi,b}^{bes} (\bar{P}_b^{bes+} - p_{t,b}^{bes+} + p_{t,b}^{bes-}) \quad (IV-35)$$

$$p_{t,\chi,b}^{r,bes} call_{\chi}^{FCAS} \leq e_{\chi,b}^{bes} (x_{t,b}^{bes} - \underline{X}_b^{bes}) \quad (IV-36)$$

$$p_{t,\chi,a}^{r,app} \leq e_{\chi,a}^{app} (ph_{t,a}^{app} + pc_{t,a}^{app}) \quad (IV-37)$$

$$p_{t,\chi,h}^{r,hp} \leq e_{\chi,h}^{hp} p_{t,h}^{hp} \quad (IV-38)$$

For all $t \in \mathbf{T}$, $\chi \in \mathbf{X}$, $r \in \mathbf{R}$, $b \in \mathbf{B}$, $a \in \mathbf{A}$, $h \in \mathbf{H}$.

The total raise FCAS commitment at GCP level, $p_{t,\chi}^r$, is aggregated using (IV-39).

$$p_{t,\chi}^r = \sum_{r \in \mathbf{R}} p_{t,\chi,r}^{r,res} + \sum_{g \in \mathbf{G}} p_{t,\chi,g}^{r,gen} + \sum_{b \in \mathbf{B}} p_{t,\chi,b}^{r,bes} + \sum_{a \in \mathbf{A}} p_{t,\chi,a}^{r,app} + \sum_{h \in \mathbf{H}} p_{t,\chi,h}^{r,hp} \quad (\text{IV-39})$$

For all $t \in \mathbf{T}$, $\chi \in \mathbf{X}$.

4.2.5.2 Lower FCAS

The lower FCAS commitments from the RES, generator, BESS, heating and cooling appliance, and electrolyzer are modeled using constraints (IV-40)-(IV-45). The RES, generator, and BESS can provide lower FCAS using their operation foot-room, i.e., by lowering their power output (see constraints (IV-40)-(IV-43)). Constraint (IV-43) ensures that there is enough headroom in the storage for the BESS to increase its charge power when the services are called at any time step. The heating and cooling appliance and electrolyzer can provide lower FCAS using their headroom, i.e., by increasing their operation power (see constraints (IV-44) and (IV-45)).

$$p_{t,\chi,r}^{l,res} \leq e_{\chi,r}^{res} (P_{t,r}^{res} - p_{t,r}^{curt}) \quad (\text{IV-40})$$

$$p_{t,\chi,g}^{l,gen} \leq e_{\chi,g}^{gen} (p_{t,g}^{gen} - \underline{p}_g^{gen}) \quad (\text{IV-41})$$

$$p_{t,\chi,b}^{l,bes} \leq e_{\chi,b}^{bes} (\bar{P}_b^{bes-} + p_{t,b}^{bes+} - p_{t,b}^{bes-}) \quad (\text{IV-42})$$

$$p_{t,\chi,b}^{l,bes} call_{\chi}^{FCAS} \leq e_{\chi,b}^{bes} (\bar{X}_b^{bes} - x_{t,b}^{bes}) \quad (\text{IV-43})$$

$$p_{t,\chi,a}^{l,app} \leq e_{\chi,a}^{app} \left(\max(\overline{Ph}_{l,a}^{app}, \overline{Pc}_{l,a}^{app}) - (ph_{t,a}^{app} + pc_{t,a}^{app}) \right) \quad (\text{IV-44})$$

$$p_{t,\chi,h}^{l,hp} \leq e_{\chi,h}^{hp} (\overline{P}_{t,h}^{hp} - p_{t,h}^{hp}) \quad (\text{IV-45})$$

For all $t \in \mathbf{T}$, $\chi \in \mathbf{X}$, $r \in \mathbf{R}$, $b \in \mathbf{B}$, $a \in \mathbf{A}$, $h \in \mathbf{H}$.

The total lower FCAS commitment at GCP level, $p_{t,\chi}^l$, is aggregated using (IV-46).

$$p_{t,\chi}^l = \sum_{r \in \mathbf{R}} p_{t,\chi,r}^{l,res} + \sum_{g \in \mathbf{G}} p_{t,\chi,g}^{l,gen} + \sum_{b \in \mathbf{B}} p_{t,\chi,b}^{l,bes} + \sum_{a \in \mathbf{A}} p_{t,\chi,a}^{l,app} + \sum_{h \in \mathbf{H}} p_{t,\chi,h}^{l,hp} \quad (\text{IV-46})$$

For all $t \in \mathbf{T}$, $\chi \in \mathbf{X}$.

4.2.6 Fast frequency response

FFR can be provided by the RES, electrolyzer, and BESS, which is modeled using constraints (IV-47)-(IV-49). Note that only the raise FFR, which is designed to respond to under-frequency events, are discussed here. This is because that the under-frequency events are more challenging to manage than over-frequency events, which is more valuable to system operators. The RES can provide FFR by operating at a curtail mode (see constraint (IV-47)), while the electrolyzer can provide FFR using its footroom (see constraint (IV-48)). Furthermore, the BESS can provide FFR by increasing its discharge power or decreasing its charge power (see constraint (IV-49)).

$$p_{t,r}^{FFR,res} \leq p_{t,r}^{curt} \quad (\text{IV-47})$$

$$p_{t,h}^{FFR,hp} \leq p_{t,h}^{hp} \quad (\text{IV-48})$$

$$p_{t,b}^{FFR,bes} \leq \bar{P}_b^{bes+} - p_{t,b}^{bes+} + p_{t,b}^{bes-} \quad (IV-49)$$

For all $t \in \mathbf{T}$, $r \in \mathbf{R}$, $b \in \mathbf{B}$, $h \in \mathbf{H}$.

The total FFR commitment is an aggregation of FFR that is provided by the RES, electrolyzer, and BESS, using constraint (IV-50). Equality constraint (IV-51) makes sure that the VPP meets the FFR obligation, P_t^{FFR} , at every time step.

$$p_t^{FFR} \leq \sum_{r \in \mathbf{R}} p_{t,r}^{FFR,res} + \sum_{h \in \mathbf{H}} p_{t,h}^{FFR,hp} + \sum_{b \in \mathbf{B}} p_{t,b}^{FFR,bes} \quad (IV-50)$$

$$p_t^{FFR} = P_t^{FFR} \quad (IV-51)$$

For all $t \in \mathbf{T}$.

4.2.7 Distribution network reliability services

The reliability services from a grid-connected microgrid¹⁰ can be provided by its surplus generation, i.e., generator, BESS, and RES, as illustrated in constraints (IV-52)-(IV-57). More specifically, the quantity of reliability services that can be provided by each technology is limited by its maximum output power (see constraint (IV-52)-(IV-54)). Moreover, the reliability service from the microgrids is defined as the surplus generation using constraint (IV-55). A dummy factor $p_t^{rel,D}$ ensures that the reliability services commitment p_t^{rel} is non-negative, even when there is no spare generation.

$$p_{t,g}^{rel,gen} \leq \bar{P}_g^{gen} \quad (IV-52)$$

¹⁰ Grid-connected microgrid is considered here as providing distribution network reliability services requiring DMES to be able to supply its internal consumers for a certain period of time without having the needs to import from the grid.

$$p_{t,b}^{rel,bes} \leq \bar{P}_b^{bes} \quad (IV-53)$$

$$p_{t,r}^{rel,res} \leq P_{t,r}^{res} \quad (IV-54)$$

$$p_t^{rel} - p_t^{rel,D} = p_{t,g}^{rel,gen} + p_{t,b}^{rel,bes} + p_{t,r}^{rel,res} - \sum_{l \in \mathbf{L}} \sum_{a \in \mathbf{A}} (ph_{t,l,a}^{app} + pc_{t,l,a}^{app}) \quad (IV-55)$$

$$0 \leq p_t^{rel} \leq Mu_t^{rel} \quad (IV-56)$$

$$0 \leq p_t^{rel,D} \leq Mu_t^{rel} \quad (IV-57)$$

For all $t \in \mathbf{T}$, $g \in \mathbf{G}$, $b \in \mathbf{B}$, $r \in \mathbf{R}$.

The reliability services often value differently depends on the quantity of the services committed, which may be non-linear. This is modeled by constraints (IV-58)-(IV-60). More specifically, adopting the approach proposed in [42], different ‘buckets’ of capacity, corresponding to different prices, are defined. The reliability can only commit within one bucket, which is ensured using (IV-59)-(IV-60).

$$p_{t,s}^{rel} \leq Mu_{t,v}^{rel} \quad (IV-58)$$

$$p_t^{rel} = \sum_{v \in \mathbf{Y}} p_{t,v}^{rel} \quad (IV-59)$$

$$\sum_{v \in \mathbf{Y}} u_{t,v}^{rel} = 1 \quad (IV-60)$$

For all $t \in \mathbf{T}$, $v \in \mathbf{Y}$.

Assuming that the location of the restoration devices and microgrid are known (i.e., for a specific case study), the reliability services can be assessed using sequen-

tial Monte Carlo simulations. That is, first, the time, location and length of contingencies are randomly generated based on the failure rate of individual lines. Afterward, the process by which the distribution restoration system isolates the fault and restores customers (including NOP operation and response time of a crew to clear the contingency) is simulated. This process is used to assess the reliability levels of the system based on preferred standards, e.g., using the SAIDI, and SAIFI. The characteristics of the reliability service provided by the microgrid can then be estimated by comparing the reliability levels with, and without support from the microgrid.

As mentioned before, the value of reliability services is not well defined. In this case, the reliability price signals are created in order to incentivize the microgrids to contribute to the distribution network reliability, based on the approach carried out in [51]. More specifically, the economic value associated with the reliability contribution from the microgrids is based on the specific value, for example, the “value of customer reliability”¹¹, on reliability level from the existing regulations, which is converted to price signals. The price signals are time-varying due to the nature of the load variations.

4.2.8 Demand response

DR can be provided by either lowering the electricity consumption or turning up the generation. More specifically, the generator can participate in DR by increasing its power output (constraint (IV-61)), while BESS can participate in DR by

¹¹ The “value of customer reliability” is expressed as a value per unsupplied MWh. In the context of NEM this value is set to \$97,500/MWh for central business district customers and \$48,750/MWh for other customers [92].

lowering its charge power or increasing its discharge power (constraint (IV-62)). Constraint (IV-63) makes sure that the BESS has enough energy stored to deliver the DR at any time. Flexible loads such as the heating and cooling appliance can also provide DR by lowering its demand (constraint (IV-64)). Factor ρ^{DR} allows that during a DR event, the heating and cooling appliance is reduced using a rolling schedule manner so that there is no significant thermal comfort impact. In this way, the heating and cooling appliances can be turned down in turn to avoid significant temperature changes in one building.

$$p_g^{DR,gen} \leq \bar{P}_g^{gen} - p_{t,g}^{gen} \quad (IV-61)$$

$$p_b^{DR,bes} \leq \bar{P}_b^{bes+} - p_{t,b}^{bes+} + p_{t,b}^{bes-} \quad (IV-62)$$

$$p_b^{DR,bes} call^{DR} \leq x_{t,b}^{bes} - \underline{x}_b^{bes} \quad (IV-63)$$

$$p_a^{DR,app} \leq \sum_{l \in L} \frac{pc_{t,l,a}^{app} + ph_{t,l,a}^{app}}{\rho^{DR}} \quad (IV-64)$$

For all $t \in \mathbf{T}, g \in \mathbf{G}, b \in \mathbf{B}, a \in \mathbf{A}$.

Depending on the specific DR program, it might only be required at certain periods of time when the peak demand is more likely to be experienced, for example, 10.00h to 22.00h on business days during the summer. In order to model this feature of the DR market, a binary parameter ω_t^{DR} is used. When the binary parameter $\omega_t^{DR} = 1$, the DR is required to be available. When the binary DR window indicator ω_t^{DR} is active, i.e., $\omega_t^{DR} = 1$, the DR commitment p^{DR} is an aggregation of the DR commitment from generators, BESS, and heating and cooling appliance.

$$\omega_t^{DR} p^{DR} = \omega_t^{DR} \left(\sum_{g \in \mathbf{G}} p_g^{DR,gen} + \sum_{b \in \mathbf{B}} p_b^{DR,bes} + \sum_{a \in \mathbf{A}} p_a^{DR,app} \right) \quad (\text{IV-65})$$

For all $t \in \mathbf{T}$.

4.2.9 Hedging contract

Caps products can be provided by generator and BESS, where the commitment p^{cap} is constrained by the generator capacity and the BESS discharge power output (see constraint (IV-66)). Furthermore, the amount of the cap contract that can be provided by generator and BESS also depends on their commitment of other markets and services, i.e., DR market, FCAS markets, and FFR service, as they both require operation headroom in the devices. This is modeled using constraint (IV-67), which ensures that the generator and BESS are able to deliver all the services when they are activated.

$$p_t^{cap} \leq \sum_{g \in \mathbf{G}} \bar{P}_g^{gen} + \sum_{b \in \mathbf{B}} \frac{\bar{P}_b^{bes+}}{\rho_b^{bes}} \quad (\text{IV-66})$$

$$\begin{aligned} \omega_t^{cap} p_t^{cap} \leq & \sum_{g \in \mathbf{G}} \bar{P}_g^{gen} + \sum_{b \in \mathbf{B}} \frac{\bar{P}_b^{bes+}}{\rho_b^{bes}} - \omega_t^{DR} \left(\sum_{g \in \mathbf{G}} p_g^{DR,gen} + \sum_{b \in \mathbf{B}} p_b^{DR,bes} \right) \\ & - \left(\sum_{g \in \mathbf{G}} p_{t,\chi,g}^{r,gen} + \sum_{b \in \mathbf{B}} (p_{t,\chi,b}^{r,bes} + p_{t,b}^{FFR,bes}) \right) \end{aligned} \quad (\text{IV-67})$$

For all $t \in \mathbf{T}, \chi \in \mathbf{X}$.

4.2.10 Network limits¹²

The network limits are modeled using constraints (IV-68)-(IV-70). Constraints (IV-68)-(IV-69) makes sure that at every time step the FCAS can be delivered without violate network limits, while constraint (IV-70) makes sure that the import and export power at GCP level is within the network limit.

$$p_t^- - p_t^+ + p_{t,\chi}^l \leq \bar{P}^- \quad (\text{IV-68})$$

$$p_t^+ - p_t^- + p_{t,\chi}^r \leq \bar{P}^+ \quad (\text{IV-69})$$

$$-\bar{P}^+ \leq p_t^- - p_t^+ \leq \bar{P}^- \quad (\text{IV-70})$$

For all $t \in \mathbf{T}$, $\chi \in \mathbf{X}$.

The maximum GCP import power $\bar{p}^{GCP}$ is modeled using constraint (IV-71), which is used to model the peak demand charge (see the eighth term in the objective function (IV-3)).

$$p_t^- \leq \bar{p}^{GCP} \quad (\text{IV-71})$$

For all $t \in \mathbf{T}$.

¹² Only the active power limits are considered here. This is reasonable on a network with spare capacity and short cables as the congestion and voltage problems should not often feature. However, on a network operating close to its capacity and with longer cables, such problem may feature, which will be further investigated in future work.

4.3 Applications

The presented model has many applications. For example, the proposed model can be used to investigate the impact of aggregations [77], the potential flexibility from different DER, the impact of various operation objectives [21], [145], and to understand the conflict and synergies between different services and markets participation [41], [73]. This section aims to demonstrate some of these potential applications. The first study demonstrates the multi-energy flexibility from different types of storage, including BESS, TES, and building thermal storage, in the context of a community energy system. Furthermore, the second case study showcases the multi-market participation and grid services provision from an integrated RES, electricity, hydrogen VPP. Lastly, the third case study analyzes the cost of energy independence.

4.3.1 Case study I – multi-energy flexibility from community energy systems

4.3.1.1 Case study description

This case study aims to demonstrate how different flexible resources, such as BESS, TES, and building thermal storages, may impact on the operation and economic performances of residential communities. The case study is based on the published work [21].

The case study is conducted in the context of VIC, Australia. The community is designed with 25 well-insulated terrace houses, with a maximum demand of 123.5 kVA. The community is connected to the wider grid through a common grid connection point, with an export/import limit of 123.5 kVA. Each terraced house is equipped with a 5.8 kW PV system. The domestic hot water demand is provided

by electric boilers, while the space heating and cooling demand are fulfilled by HVAC systems¹³. The domestic hot water demand, electricity base load, house occupancy levels, as well as the building thermal capacitance/resistance are based on [22], [151]. The desired building temperature when the occupants are active is set to 21 °C.

The community is designed to expose to two different energy price signals, i.e., a flat retail price, or a time-varying dynamic price. The flat retail price is set to be 0.25 \$/kWh for importing electricity while 0.05 \$/kWh for exporting electricity to the grid. The time-varying dynamic price is illustrated in Figure IV-2, which consists of energy cost, use of system fee, retail policy costs, network policy costs, and GST.

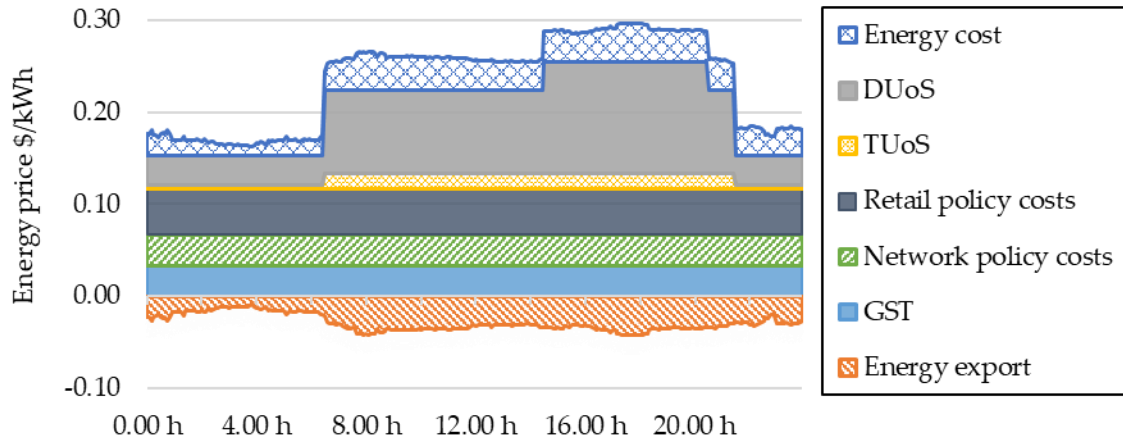


Figure IV-2. Time-varying dynamic energy price [21]

In order to assess the multi-energy flexibility from the community energy systems, various flexibility options are considered, i.e., BESS, TES, and building tem-

¹³ The control strategy that is applied to HVAC systems in this thesis aims at altering the heating and cooling supply, thus moderating the power consumption of the whole HVAC system.

perature flexibility. The building temperature flexibility allows the building temperature to deviate from the set temperature within a certain band for a short amount of time. By using the building thermal storage, i.e., store the thermal energy in building fabrics, the building temperature flexibility also allows pre-heating or pre-cooling of the buildings, which provide additional flexibility.

The test cases are described in Table IV-1. Test case 0, which has no flexibility option and is optimized under the energy minimization objective, is set as a base case. Test cases 1-6 are operated under the cost minimization objective. More specifically, test cases 1, 2, and 3 have the flexibility options of BESS, TES, and building temperature flexibility, respectively, and are applied with the flat retail price. Moreover, test cases 4, 5, and 6 are tested under a time-varying dynamic price, with the flexibility option of BESS, TES, and building temperature flexibility, respectively.

Table IV-1. Test case description

Test case	Flexibility option	Objective	Price signal
0	None	Energy minimization	Retail price
1	BESS	Cost minimization	Retail price
2	TES	Cost minimization	Retail price
3	Building temperature flexibility (up/down)	Cost minimization	Retail price
4	BESS	Cost minimization	Dynamic price
5	TES	Cost minimization	Dynamic price
6	Building temperature flexibility (up/down)	Cost minimization	Dynamic price

The sizes of flexibility resources for each terrace house under test case 0-6 are shown in Table IV-2. More specifically, for test case 1 and 4, the BESS is sized to have a maximum charge/discharge power of 3.5 kW, with a capacity of 5 kWh. The round trip efficiency of the BESS is assumed to be 0.9. Moreover, the TES is sized to 80 liters [152] for test case 2 and 5. For test cases 3 and 6, it is assumed that the

building temperature can have a deviation of $\pm 0.5^{\circ}\text{C}$ from the set temperature, i.e., 21°C .

Table IV-2. Size of flexibility resources, per building

Test	PV capacity	Flexibility resource	Size
0	5.8 kW	None	---
1,4	5.8 kW	BESS	5 kWh/3.5 kW
2,5	5.8 kW	TES	80 liters
3,6	5.8 kW	Building temperature flexibility (up/down)	$\pm 0.5^{\circ}\text{C}$

4.3.1.2 Results and discussion

The operational behavior of the community with various flexibility resources under different price signals on a peak summer day are presented in Figure IV-3. Moreover, the energy storage level of BESS and TES, and temperature deviation from the building set temperature is also indicated in Figure IV-3. It can be seen that different flexibility resources result in distinct operational behavior of the community, while the tests with the same flexibility resource also have very different operational behavior under various price signals.

When the community is facing a flat retail price signal (i.e., test case 1, 2, and 3), it is optimized to minimize the overall electricity import from the grid and maximize the electricity export, in order to minimize the net costs. Moreover, as the electricity export price is substantially lower than the electricity import price, minimizing electricity import is prioritized when operating the community. As a result, the flexibility resources are used to store the excess electricity generation from PV during the day and discharge during the night when PV is not available so as to reduce the electricity import. However, BESS, TES, and building thermal storages have distinct charging and discharging behaviors for test case 1, 2, and 3. In test case 1, the BESS is charged throughout the day using the excess PV generation,

while a more concentrated charging behavior can be observed for TES between 14.00h to 17.00h so as to minimize the energy losses from TES to the environment. For test case 3, the HVAC is operated to pre-cool the building at 16.00h using the excess PV generation to reduce the electricity import during the night, which leads to a maximum temperature surplus at 18.00h.

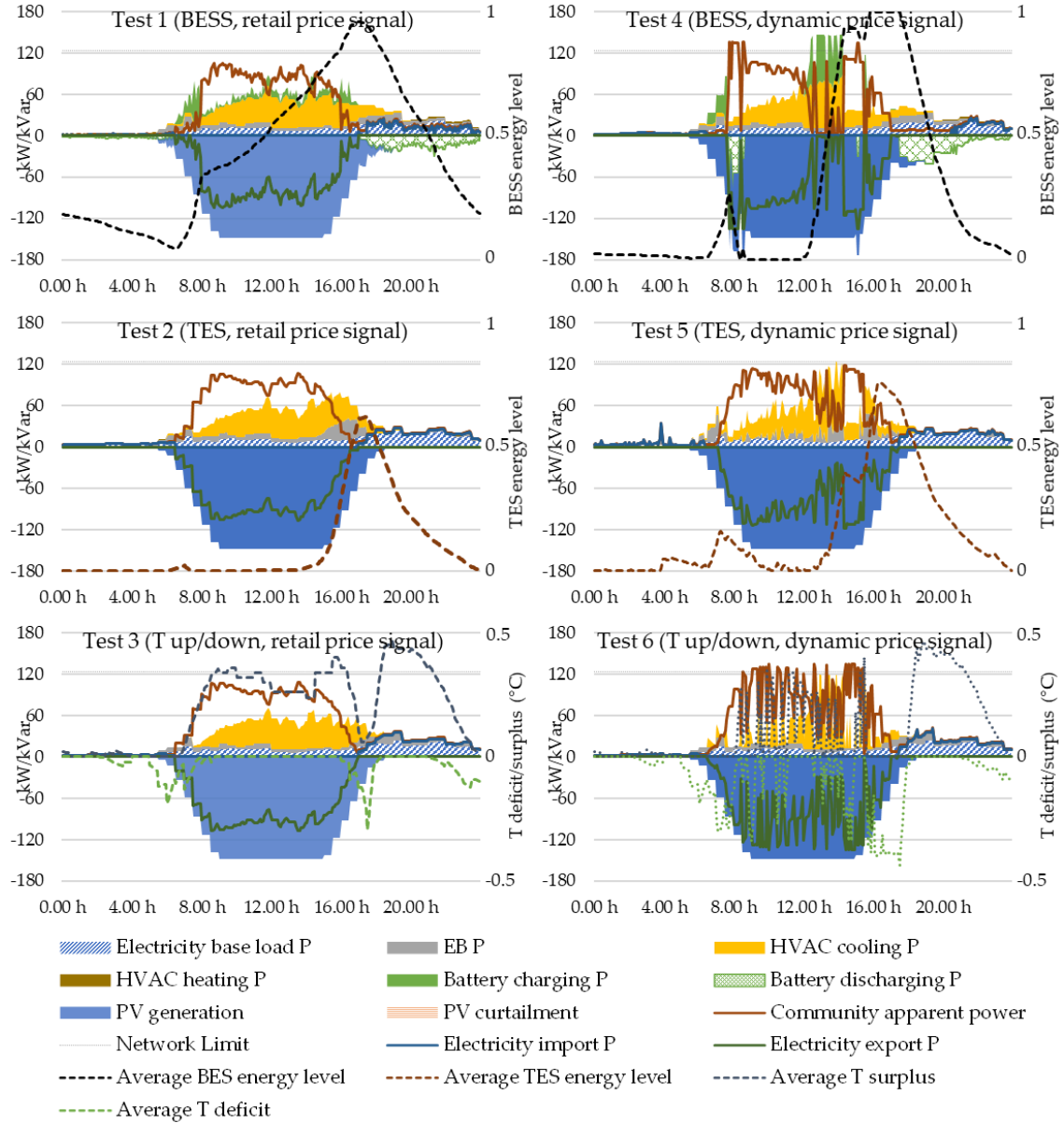


Figure IV-3. Community energy system operational behavior for test case 1-6 on typical peak summer day [21]

Test case 4, 5, and 6 have the same objective with test case 1, 2, and 3, i.e., minimize the net costs, but under a dynamic price signal (see Figure IV-2). This is achieved by utilizing the storages, firstly, by shifting electricity import from high price periods to lower price periods, and secondly, by shifting electricity export from low price periods to higher price periods. Thus, two concentrated exporting periods can be observed, i.e., 8.30h, and 16.00h, which corresponding to high export price periods (see Figure IV-2). The BESS and TES are charged from 7.00h to 8.00h and 14.00h to 15.30h, corresponding to low electricity price periods, in test case 4 and 5 respectively, while are discharged at 8.30h and 16.00h in order to increase electricity export. More fluctuations of the building temperature are experienced during the day in test case 6 than test case 3, as a result of the significant changes in HVAC operation in response to the electricity prices, aiming to shift the electricity export/import.

The annual cash flow of test cases 1-6, as well as the annual net cost of test case 0 (the black dash line), are shown in Figure IV-4. Compared with test case 0, significant cost savings can be observed for all test cases. By implementing flexibility resources, the electricity imported from the grid is reduced which results in a reduction in the cost of electricity import. Moreover, when facing time-varying dynamic electricity prices, the flexibility resources are able to shift the electricity import/export to lower/higher price periods, which further reduce the electricity cost, especially the TUoS and DUoS costs, which have the most remarkable differential throughout the day (see Figure IV-2).

Among all the flexibility resource options, the BESS brings the most significant cost savings, i.e., in test 1 and test 4, while the building temperature flexibility

brings the least cost savings, i.e., in test 3 and test 6. However, one of the drawbacks of the BESS is that it requires expensive investments. On the contrary, building temperature flexibility can be provided by already existing technologies such as HVAC, which might become an attractive option for consumers.

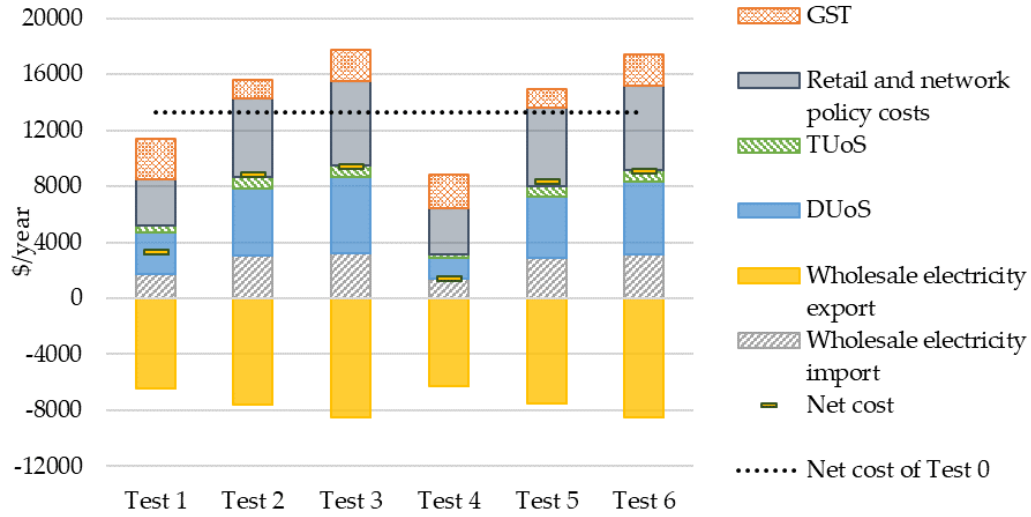


Figure IV-4. Annual cash flow for test case 1-6, and annual net cost for test case 0 [21]

4.3.2 Case study II – virtual power plant with hydrogen-based devices

4.3.2.1 Case study description

This case study aims to analyze the flexibility coming from P2G and BESS, as well as their ability to participate in multiple markets and provide grid services, in the context of a VPP. Moreover, this case study also aims to demonstrate the suitability of P2G and BESS providing the new services that require fast response, such as FFR.

The case study is designed based on a remote area of the South Australia network, which is weakly connected to the NEM with a large amount of RES generation. A multi-energy VPP is proposed in order to successfully integrate RES using

flexible resources. The options of flexible resources include installing an electrolyzer which is able to convert the exceeded RES generation to hydrogen [153], and/or installing a BESS.

The proposed VPP consists of a wind farm, a solar farm, an electrolyzer, a BESS, hydrogen storage, and a hydrogen-based OCGT, and is designed to participate in multiple markets and provide grid services. An illustration of the proposed VPP is shown in Figure IV-5. The wind farm has a capacity of 66 MW, and the generation profile is based on five-minute generation data provided by AEMO [80]. The solar farm has a maximum capacity of 15 MW, while the generation profile is based on the solar irradiance profiles that are available at [154]. The OCGT has a minimum power output of 2 MW and a maximum power output of 10 MW, with a COP of 0.35. The electrolyzer has a maximum power of 5 MW with a COP of 0.75. The BESS has a maximum charge/discharge power of 5 MW, an energy capacity of 8 MWh, and a round trip efficiency of 0.9. The hydrogen storage has a capacity of 200 MWh.

The VPP participates in the wholesale electricity market, hydrogen market, and six contingency FCAS markets. The wholesale electricity and FCAS market prices are based on five-minute prices of the SA region taken from AEMO [80], while the hydrogen price is set as 63 \$/MWh which is based on [155]. It is assumed that the BESS and electrolyzer participate in all six contingency FCAS markets, i.e., fast/slow/delayed raise/lower FCAS. The RES, i.e., the wind farm and solar farm, participate in fast/slow raise/lower FCAS but not delayed raise/lower FCAS, due to the uncertainty of the natural resources the services may not be able to sustain

to meet requirements of the delayed services. Last but not least, the OCGT participates in slow/delayed raise/lower FCAS. The VPP is also designed to fulfill the solar farm FFR obligations, i.e., to provide upward flexibility that is equivalent to half of the solar generation at all the time, using the BESS and electrolyzer. It is assumed that the VPP is connected to the wider grid through a single GCP, with an export/import limit of 108 MVA.

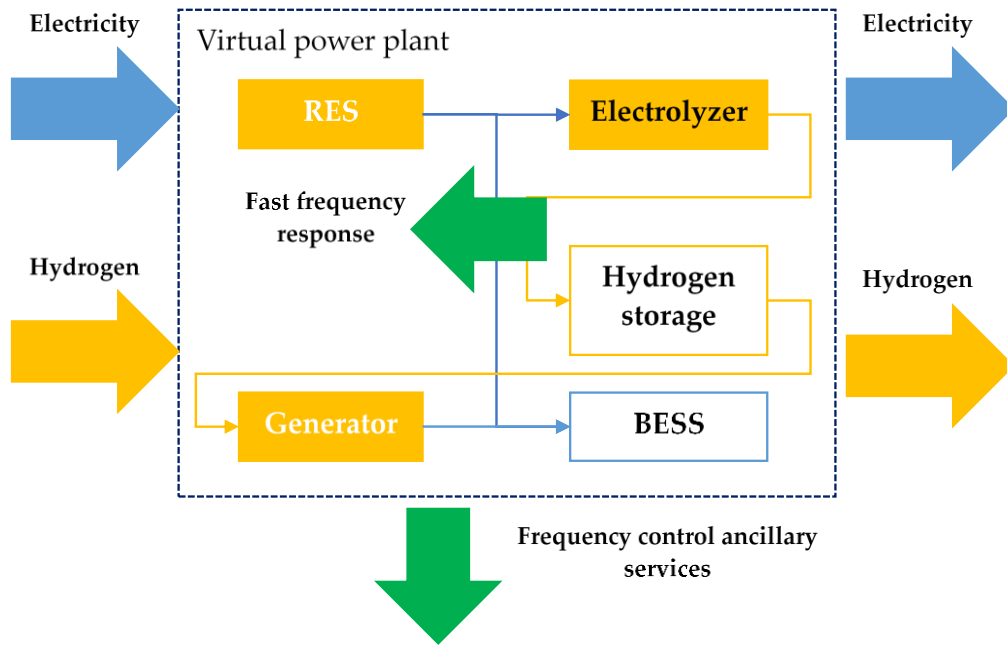


Figure IV-5. Illustration of purposed VPP

4.3.2.2 Results and discussion

Figure IV-6 illustrates the operational behavior of OCGT, solar farm, wind farm, BESS, electrolyzer, as well as the electricity import/export from the grid, on a relatively high RES generation and low electricity price day. Figure IV-6 also shows the corresponding wholesale electricity prices and fast raise/lower FCAS prices. From Figure IV-6 it can be seen that negative electricity price is experienced at time t_B . The fast raise FCAS price is significantly higher than the fast lower FCAS

price, which reaches its peak at t_A . The wholesale electricity price is considerably low on the presented day, thus the OCGT is not operated on that day due to its high operational cost.

The operation of BESS is driven by the electricity price, FCAS price, and FFR obligation. Specifically, during the night, when there is no solar generation, the BESS is mainly driven by wholesale electricity prices and is used to charge during the lower electricity price periods and discharge at higher price periods. This is because during the night the FCAS raise price is relatively low (except at time t_A), and more benefits can be gained by doing energy arbitrage. During the day, the BESS is used to fulfill the solar farm's FFR obligation, together with the electrolyzer. The BESS can use its footroom to provide FFR during the charging mode, while it is also able to use its headroom to provide FFR during discharging, either itself or in conjunction with the electrolyzer. It can be seen that at both time t_A and t_B , the BESS is charged at its maximum power. However, the initiatives are different. At time t_A , when the raise FCAS price reaches its peak, the VPP tends to maximize its raise FCAS participation, whereas at t_B , when the wholesale electricity price becomes negative, the VPP tends to maximize its electricity import to achieve more revenues from the wholesale electricity market.

The operation of the electrolyzer is mainly driven by wholesale electricity prices and FCAS prices. It can be seen that the electrolyzer is operated to produce hydrogen most time of the day during the low electricity price periods. The electrolyzer is shut down from 17.00h to 19.00h, driven by high wholesale electricity prices. The electrolyzer also uses its operation footroom to provide the FFR obli-

gation of the solar farm in addition to the BESS. At time t_A , the electrolyzer is operated at its maximum power in order to contribute to the VPP raise FCAS participation, while at time t_B , it is operated at maximum power so as to increase the electricity import of the VPP.

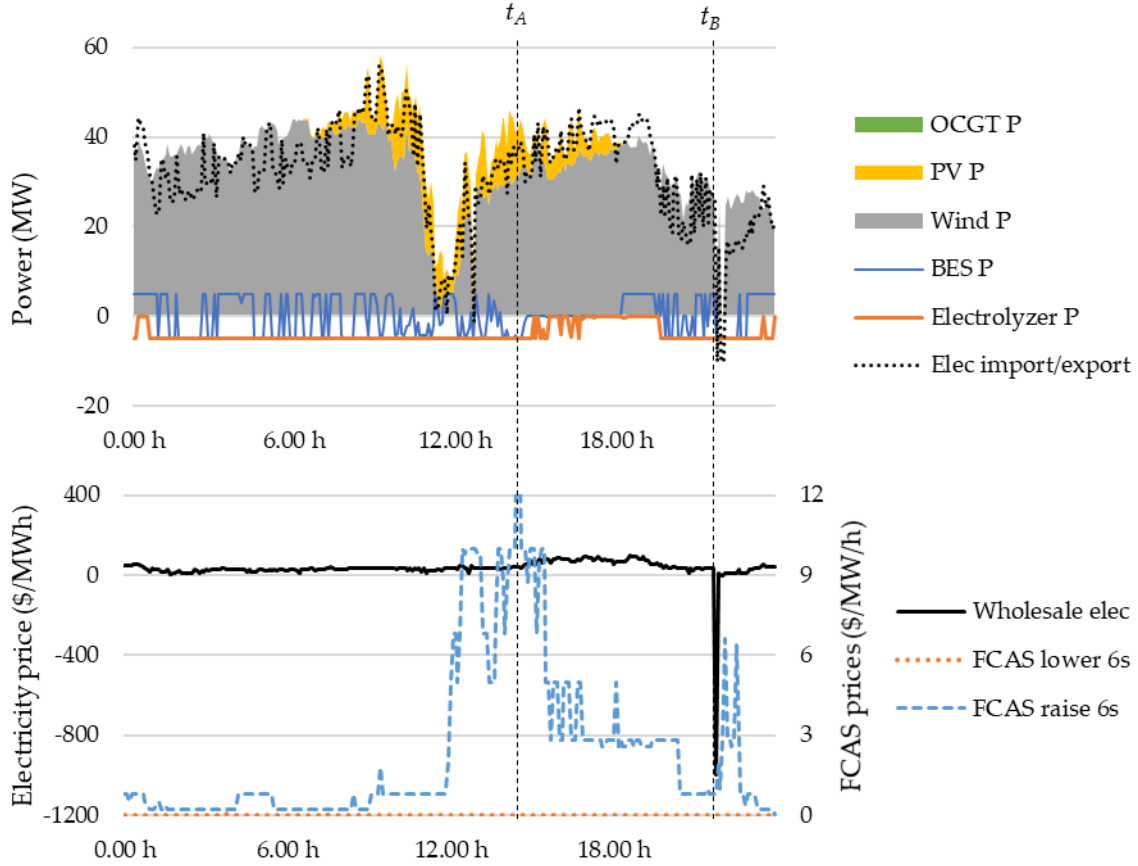


Figure IV-6. VPP operation behavior against market prices, on a high RES generation and low electricity price day¹⁴

Figure IV-7 shows the operational behavior of the technologies, the electricity import/export from the grid, and the corresponding wholesale electricity prices and fast raise/lower FCAS prices, on a relatively low wind generation and high

¹⁴ In the top figure, which shows the operational behaviour of the technologies, a positive number represents generation while a negative number represents consumption.

electricity price day. It can be seen that the wholesale electricity price reaches its peak at t_c . The fast lower FCAS is also significantly lower than fast raise FCAS.

On this day, the operation of BESS and the operation of electrolyzer are both mainly driven the wholesale electricity prices. Moreover, BESS is also prioritized when providing FFR. This is because that the BESS has a much higher COP than electrolyzer, which is more profitable at higher wholesale electricity price periods when producing hydrogen is not beneficial. At time t_c the wholesale electricity price reaches 15,000 \$/MWh, which leads to the shut-down of the electrolyzer. However, it is interesting to note that the BESS is in its charging mode, which reduces the potential electricity export. This is because the BESS is used to provide FFR service to fulfill the solar farm's FFR obligation at t_c . The peak wholesale electricity price also incentivizes the OCGT operation to further increase the electricity export at time t_c .

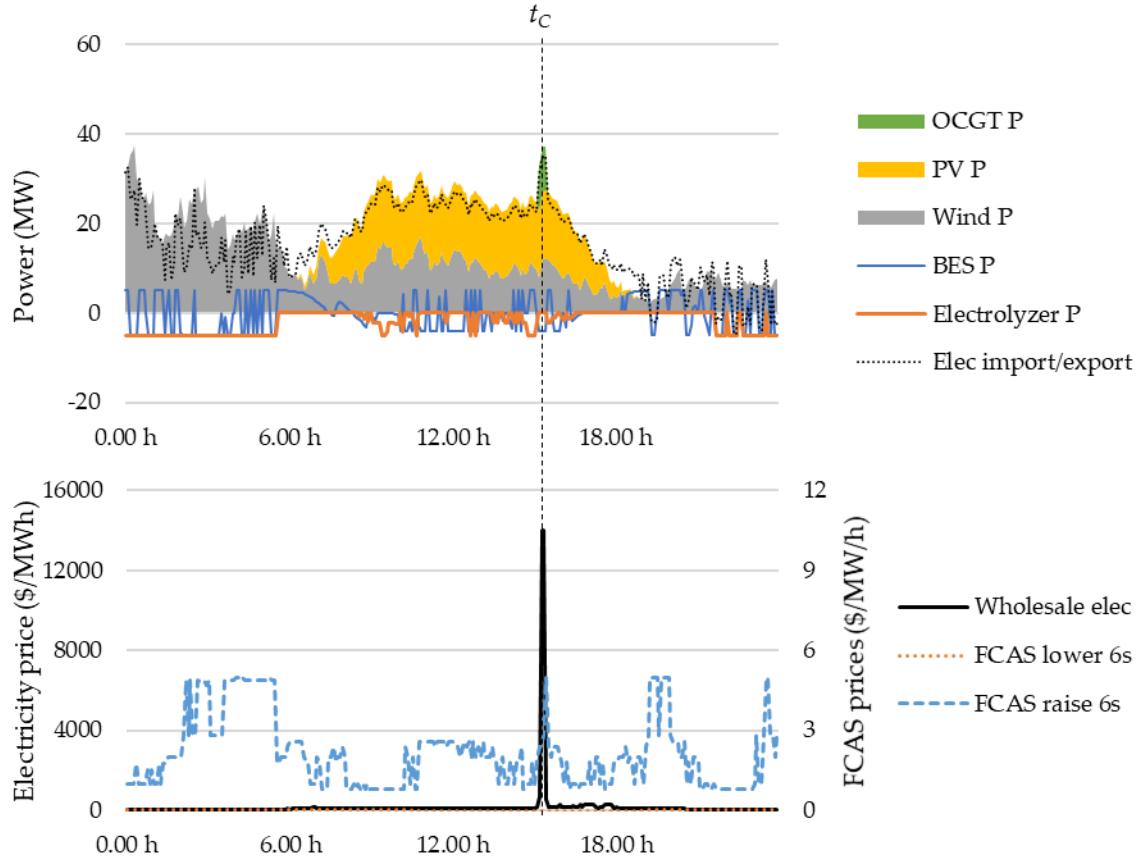


Figure IV-7. VPP operation behavior against market prices, on a low RES generation and high electricity price day

From the operational behavior of technologies, it can be concluded that when the electricity is moderate or high, the priority of FFR provision is from the BESS instead of the electrolyzer. This is because, first, the BESS can provide FFR in both charge and discharge mode which is more flexible than the electrolyzer. Secondly, the round trip efficiency of BESS is comparably higher than the COP of the electrolyzer, which means using electrolyzer to provide FFR may potentially increase the energy import from the grid. When the electricity price is low, the electrolyzer is preferred as the FFR provider, as by using low price electricity to produce hydrogen leads to more economic benefits.

4.3.3 Case study III – energy independence of microgrids

Concurrently, the rising costs of primary energy, high expectations of energy system reliability, and measures to decarbonize energy supply are increasing the cost of energy to consumers. In Australia, the retail prices of electricity had a rapid increase of 72% in the decades to June 2013 [156], while the network costs, which is the levelized cost of the grid transmission and distribution infrastructure, contributed to more than 50% of the energy bill in most of the states [157]. In rural areas with low population density, grid operation, maintenance, and expansion are particularly expensive, which might lead to even higher network costs for the consumers. According to the South Australia Networks company, 70% of their investment is spent to meet 30% of the demand in the rural area [158]. In this scenario, the minimization of reliance on the grid is considered a worthy objective for a district.

This introduces a clear tension between motivations to interact with the grid, to obtain revenue from providing system services, and to isolate from the grid, to avoid liability for the costs of maintaining the grid. At present, the fast-reducing prices of DER, increasing energy prices and lack of opportunities for small parties to provide system services mean that there is often more interest for consumers and communities in becoming less reliant on the grid [4]. These motivations have given rise to several ideas. Firstly there is the concept of *net-zero buildings/districts*, or related ideas such as *energy positive neighborhoods* [159]–[163] where the amount of electricity exportation equals or exceeds the electricity import over a period, often a year [163], [164]. Moving to a finer temporal resolution, the concept of energy (more accurately, electricity) independence (also often referred to as *energy autarky*,

energy self-sufficiency, and *energy self-reliance*; henceforth we refer to electricity independence¹⁵) is of interest. Electricity independence can be defined as the situation where a consumer or subset of consumers (e.g., a community, district or region) relies on its own generation to satisfy its demand [165]. Different from the concept of net-zero or energy positive consumers, electricity independence requires complete autonomy and implies off-grid operation [166].

The concept of energy independence is well recognized in the literature. Most of the assessment and business cases are focusing on single house level, with the particular focus on PV coupling with storage systems, i.e., PV-battery systems [4], [167]–[172], PV and hydrogen storage system [160], [172], and PV and thermal storages [173]. Coupling PV with energy storage could improve household electricity independence [167], however, the degree of electricity self-sufficiency is very limited without large storage capacities, and electricity independence cannot be achieved unless the system is excessively oversized [4], [168]–[172]. Adding co-generation sites to PV and energy storage buildings can significantly improve household electricity self-sufficiency level and reduced the size of the storage that is required [174]. Even then leaving the grid is financially infeasible, due to the high installation costs of the storages [174]. The aggregation has been recognized as having a beneficial effect on electricity self-sufficiency due to the diversity of demand and generation profiles, and the opportunity to self-supply within the aggregation [166], [175]. More specifically, comparing with a single household, the

¹⁵ ‘electricity self-sufficiency will also be referenced; 100% self-sufficiency = electricity independence

aggregation of different households can reduce the fluctuations in the energy demand, while also decrease peak demand, due to the superposition of different individual demand profiles. Thus, at a high aggregation level (e.g., at the district level), the costs of increasing energy self-sufficiency are significantly lower than at the single house level [166].

Perhaps due to the simplicity of the electricity independence objective, being related to electricity flows and disregarding economic elements, a truth sometimes not recognized is that the techno-economic and environmental performance of a district will be distinctive under objectives of electricity independence and electricity independence. This is because, although going off-grid can avoid expensive energy costs, becoming electricity independent might require expensive investment in DER. Moreover, disconnection from the grid will prevent consumers from gaining economic benefits from providing various grid services, which might further reduce operational revenue [21], [145], [176], [177]. In this context, this case study aims to assess the techno-economic performances of energy independence so as to reveal the true cost of energy independence.

4.3.3.1 Case study description

Various tests are conducted using the proposed model, in the context of VIC, Australia. Three residential districts are performed under different operation objectives, i.e., energy minimization, electricity independence, and cost minimization. The case study aims to demonstrate the technical and economic performances of both leaving the grid and remaining in the grid under different operation objectives. A sensitivity analysis of the changes in electricity prices is also conducted.

The district consists of 50 well-insulated detached houses, which are designed to have diverse appliances and occupancy profiles. The district has an annual space heating demand of 115 MWh_{th} and an annual space cooling demand of 1056 MWh_{th}. Each detached house is equipped with an HVAC system to satisfy the space cooling and heating demand.

In order to understand the influence of different technology mixes on the techno-economic of the district and the cost of going off-grid, three districts, namely District A, District B, and District C, with various DER combinations are proposed. The technology type and size are shown in Table IV-3. The first district, i.e., District A, is designed with PV and BESS which is able to meet the electricity demand of the district. PV is sized to 4250 m² so as to meet the maximum daily electricity demand. The BESS is then sized to 1500 kWh_e /900 kW_e, which is used to achieve zero interaction with the grid. Each detached house is also equipped with an electric boiler to meet the domestic hot water demand. District B is equipped with a centralized gas-fired CHP unit coupled with a TES to supply the space heating demand and domestic hot water demand through a district heat network. The CHP is also used to meet the district's peak electricity demand which is sized to 453 kW_e with a thermal efficiency of 0.47 and an electrical efficiency of 0.37 [20]. The TES is economically sized to 33970 L [20], which is equivalent to 985 kWh_{th}. The third district, District C, is designed with CHP, TES, PV, and BES. The centralized gas-fired CHP is sized to 163 kW_e which is able to meet the district's peak heating demand, with a thermal efficiency of 0.47 and an electrical efficiency of 0.37 [20]. The TES is economically sized to 13578 L, which is equivalent to 394

kWh_{th} [20]. The PV is sized to 2395 m² to be able to meet the rest of the daily electricity consumption. The BESS is sized to 240 kWh_e/144 kW_e, which ensures that the district can achieve zero electricity import/export.

The energy prices, FCAS prices, and cap contract prices are taken in the context of Victoria, Australia [178], [179]. The retail electricity import price is composed of electricity wholesale prices, policy costs, network charges, and goods and services tax (GST). Static retail price is set as 0.25 \$/kWh for electricity import and 0.05 \$/kWh for electricity export. Figure IV-8 shows the dynamic electricity prices on summer weekdays and winter weekdays. The gas price is 0.074 \$/kWh, taking from [180]. The contingency FCAS market prices are taken from AEMO [80]. Figure IV-9 shows the FCAS prices on a summer weekday and winter weekday. Table IV-4 shows the cap contract prices in VIC [179].

Table IV-3. Technology sizes of District A, B, and C

	PV	BES	CHP	TES
District A	3750 m ² (515kW _e)	1250 kWh _e /750 kW _e	-	-
District B	-	-	453 kW _e /575 kW _{th}	33970 L (985 kWh _{th})
District C	2395 m ² (330kW _e)	240 kWh _e /144 kW _e	163 kW _e /207 kW _{th}	13578 L (394 kWh _{th})

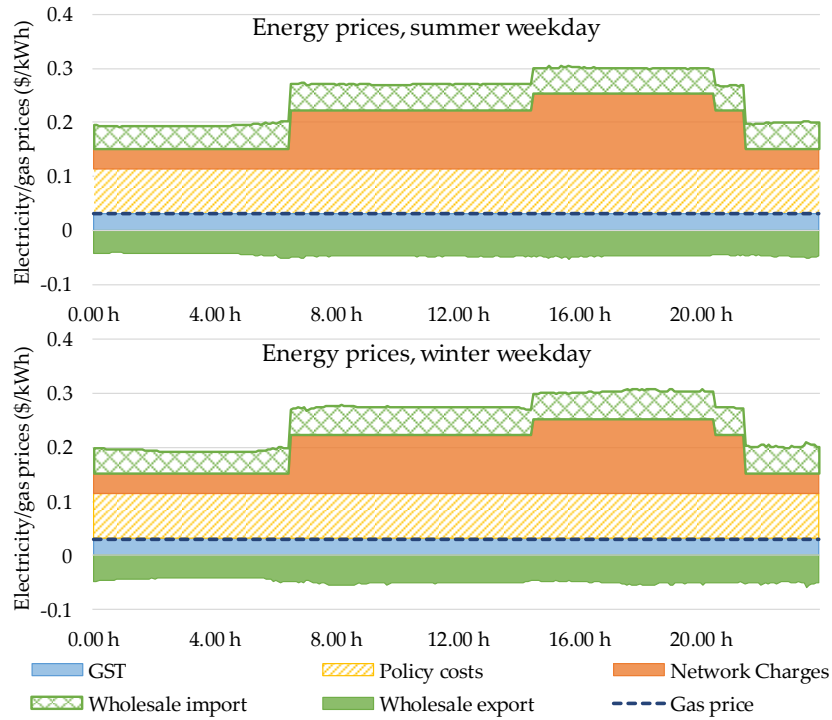


Figure IV-8. Dynamic electricity and gas price signals for summer weekdays (left) and winter weekdays (right)

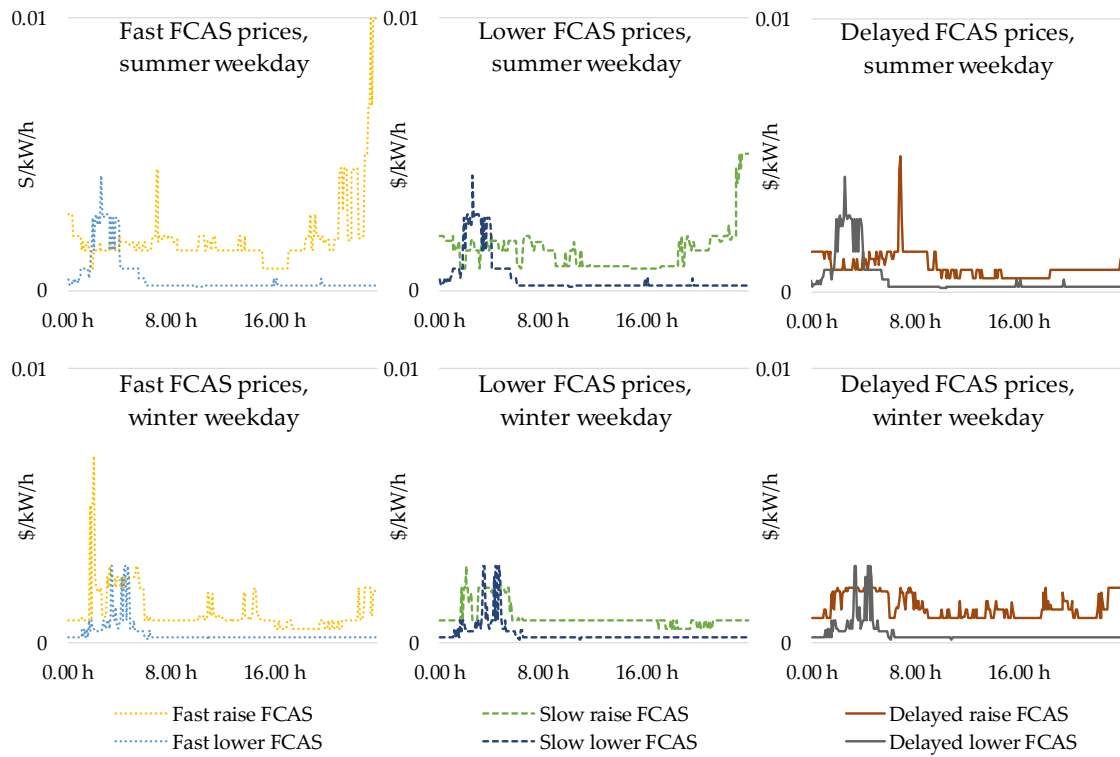


Figure IV-9. FCAS prices signals for summer weekdays (top) and winter weekdays (bottom)

Table IV-4. VIC cap prices

Season	Winter	Shoulder	Summer
Price	4.5 \$/MWh	3.0 \$/MWh	39 \$/MWh

Four tests with different combinations of objectives and price signals are considered for each district. The base case, i.e., test 1, is tested under the energy minimization objective, in line with the current practices where customers face a flat retail energy price signals, without any market participation. test 2 is run under the electricity independence objective, aiming to minimize the interaction with the grid. test 3 and test 4 are modeled under the cost minimization objective. More specifically, retail energy prices are applied to test 3, while the district does not partake in and markets. The district is exposed to dynamic energy prices in test 4, with multi-market participation. Business as usual (BAU), i.e., a district without DER installation and is optimized under energy minimization objective with flat energy prices, is also modeled for the economic analysis.

Table IV-5. Test description

Test	Objective	Price signal	Market participation
1	Energy minimization	Retail energy prices	-
2	Electricity independences	Retail energy prices	-
3	Cost minimization	Retail energy prices	-
4	Cost minimization	Dynamic energy prices	FCAS and Cap contract

4.3.3.2 Results and discussion

A selected group of tests and results for District A, B, and C are presented and discussed. The economic performances, including annual cash flow and discounted payback period (DPP) for DER, are presented to illustrate the economic performances of each test. Summer weekday is selected to demonstrate the technical performances of the district under different conditions. Finally, sensitivity

analyses are presented in order to demonstrate how techno-economic performances for the district change with different electricity prices scenarios.

Figure IV-10 shows the economic performances for District A, B, and C, compared to the annual cash flow of BAU. Significant cost savings can be found across all the tests and districts. Test 1 has the highest operation costs among the four tests for all districts, which is seen as a baseline case when comparing the economic performances of the districts under different objectives. Under electricity independence objective, i.e., test 2, there is no electricity-related revenue and cost, as the district avoids electricity import and export and achieves complete electricity independent. For test 3, i.e., cost minimization objective without grid services provisions has similar but slight fewer overall costs compared with test 2 for all districts. However, for all test 3, higher energy-related costs can be observed, meanwhile higher electricity-related revenue is achieved. That is due to the energy market participation under the cost minimization objective, during which the district tends to import electricity at lower import prices, and export electricity at high export prices. For test 4, under cost minimization objective with grid services provision, substantial revenues are gained from providing FCAS and from cap contract, compared with test 3. Due to different capabilities of the technologies of providing different grid services, the revenues also vary significantly for different districts. For example, for District A, the BESS is able to participate in all FCAS markets, while for District B, the CHP is only able to provide delayed FCAS. Among all the districts, District A, equipped with PV and BES, has the highest revenue from grid services provision, accounting for 90% of the total revenue, of which 45% comes from participating in FCAS markets and 55% from cap contract. District B and C have similar revenues from grid services provision that account

for 73% of their overall revenues. However, FCAS revenue makes up 48% of the total grid services revenue for District C, while only accounts for 34% of the revenue from grid services provision for District B.

District A has the least overall operation costs, but the highest DPP among all districts, due to the high investment costs of PV and BESS. On the contrary, District B has the highest overall operation costs, but the lowest DPP. By using PV and CHP to supply the consumers' demand, i.e., District C, a significant reduction in the DPP can be seen compared to District A.

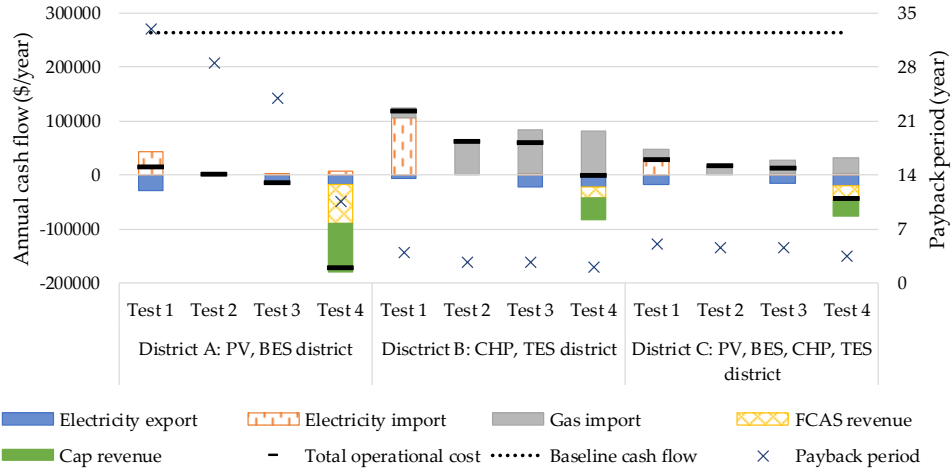


Figure IV-10. Annual cash flows compared to BAU and DPP

The operational behavior of District A, B, C on summer weekdays for test 2-4 is presented in Figure IV-11. For District A and District C, the operation of the DERs changes slightly according to different objectives. For test 2, under the electricity independence objective, the DERs are operated in a way to avoid electricity import. That is, the BESS (for District A and District C) is charged during the day using PV generation, is discharged from 17.00h onwards to meet the electricity demand. Similarly, the CHP (for District B and District C) is operated in order to

meet the electricity demand for space cooling and domestic hot water demand. The exceed PV generation for District A and District C is curtailed instead of exported.

Under the cost minimization objective without grid services provision, i.e., test 3, the district operation is driven by energy prices. In order to maximize the overall profit, the district tends to shift its electricity export to higher price periods and avoid electricity import using flexible resources such, i.e., TES (District B and District C) and BESS (District A and District C). The district export electricity using exceed PV generation and BESS from 7.00h-17.00h, corresponding to high electricity export prices (see Figure IV-9). For District B and C, the CHP is only operated to avoid electricity import but not for electricity export, as exporting electricity using CHP generation is not economically attractive under today's gas prices.

For test 4, under cost minimization objective with grid services provision, the district overall profit is maximized by participating in energy markets, FCAS markets, and cap contract market. It can be seen that the CHP operation does not change for District B and C when comparing test 3 and test 4, meaning that the operation of CHP is mainly driven by the energy prices. On the contrary, the operation of BESS changes when considering grid services provision for District A and District C. For instance, for both District A and C, the BESS tends to have higher energy level during the night time, i.e., from 21.00h-24.00h when fast raise FCAS price reaches the peak price (see Figure IV-9), in order to provide fast raise FCAS. Overall, the changes in operation are minor, pointing out that the district operation is mainly driven by energy prices.

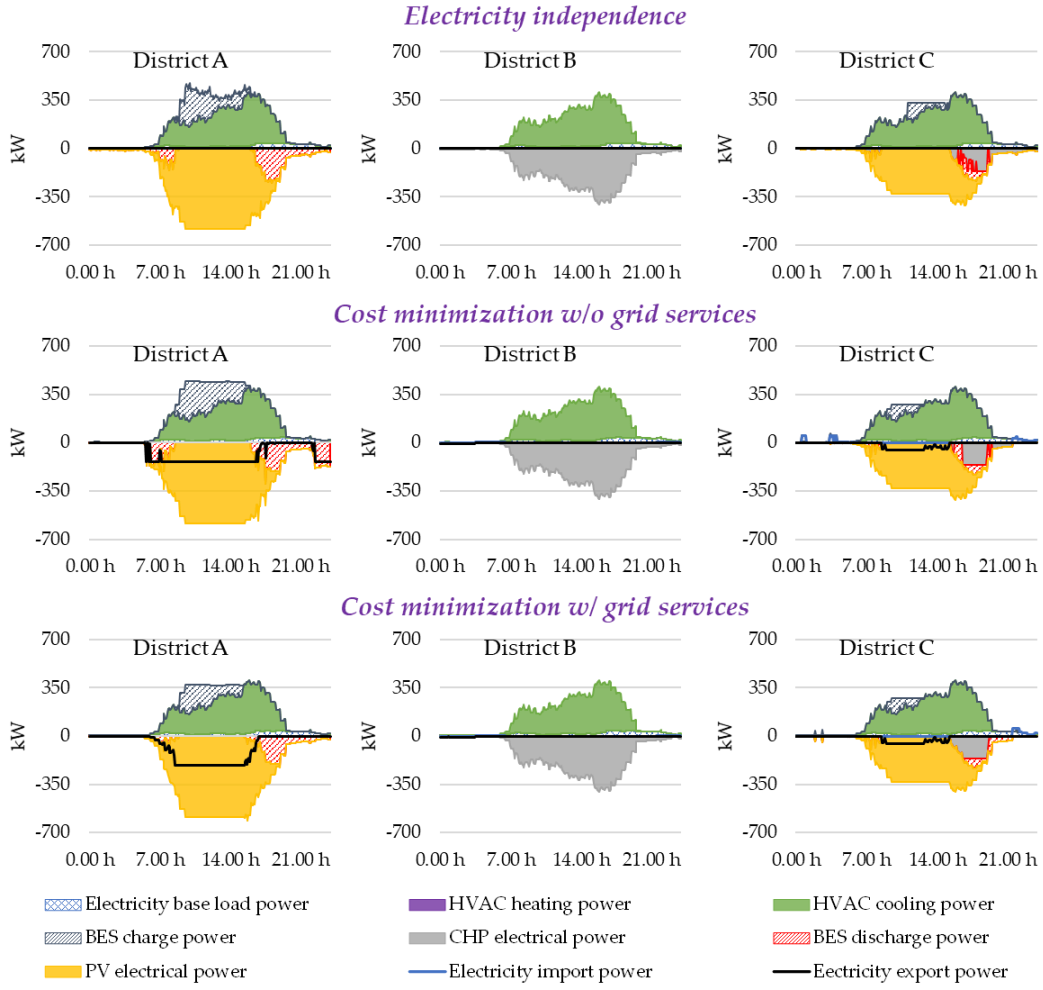


Figure IV-11. Operational behavior for District A, B, and C for Test 2-4 on summer weekdays

Figure IV-12 shows the annual cash flow for test 1-4 for District A, B, C, under different electricity prices, varying from the same as the electricity tariff to two times of the electricity tariff in the base case. It can be noticed that the increase in electricity prices only has major influences on test 1, for all districts, as the districts' operations do not change with the electricity prices variation. Under electricity independence objective, i.e., test 2, as the districts do not exchange electricity with the grid, the annual cash flow remains the same. For test 3 and test 4, under a cost minimization objective, the overall profits have slightly decreased when the electricity prices increase. The districts tend to be electricity self-sufficiency and self-consumption, which leads to decreases in electricity import costs and electricity

export revenues for all districts. The gas import costs for District B and C also decrease as less electricity is generated to export. An increase in FCAS revenue for District B and C can be observed, which is mainly because as less electricity is exported more spare capacity of CHP can be used to partake in FCAS markets. From the results, it is concluded that going “off-grid” is not economically viable under all price scenarios.

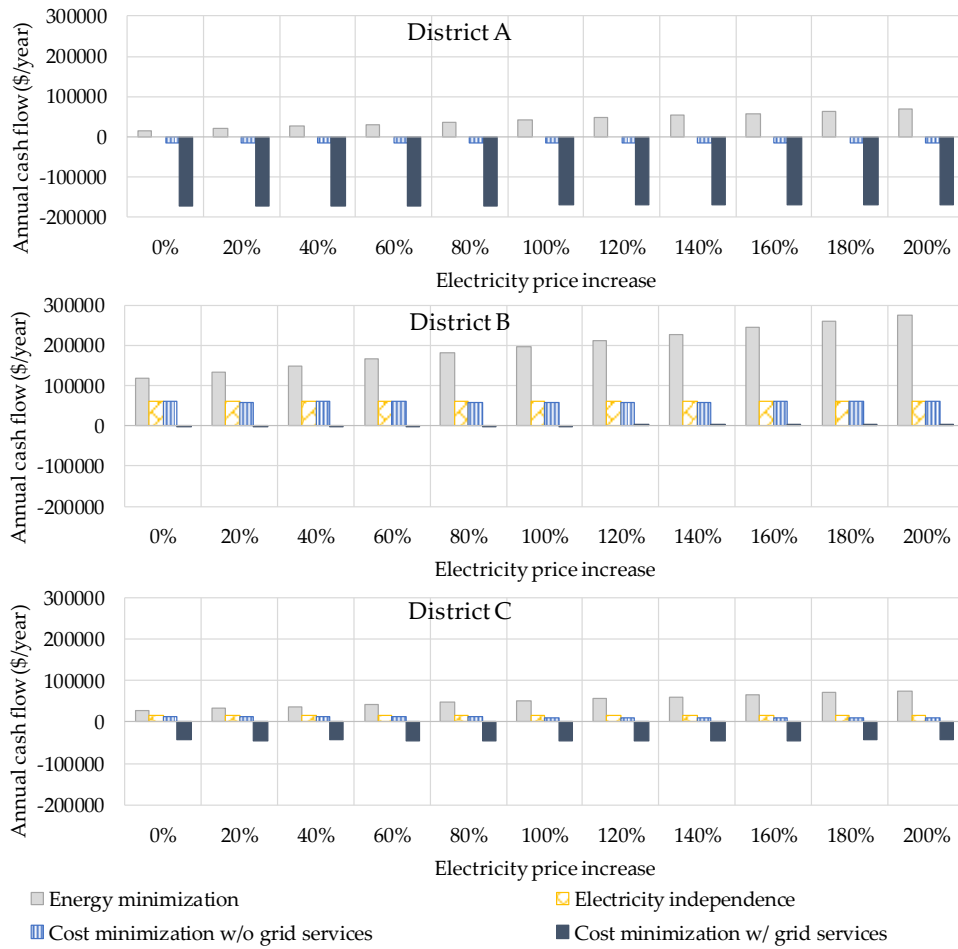


Figure IV-12. Annual cash flow for Test 1-4 with various electricity prices

4.4 Summary

In this chapter, a multi-market, multi-service co-optimization model for DMES operation is introduced. This model aims to co-optimize the simultaneous multi-

market participation, multi-service provision, as well as the operation of the technologies within the DMES, in order to achieve different objectives. This model properly models both technical constraints and economic constraints, while considering simultaneous multi-market participation and grid services provisions. With regard to the technical constraints, the technical characteristics of various technologies, such as generator, RES, BES, TES, electrolyzer, and heating and cooling appliances, are considered. With regards to the commercial constraints, different market structures and commercial regimes are modeled. Moreover, various price signals for markets and grid services are applied, in order to exploit the potential flexibility from the DMES. Appropriate time-resolution, i.e., five-minute, is used, in line with market operation in the context of NEM.

A number of case studies are conducted to demonstrate the proposed model, including a comparison of various flexibility resources in the context of a community energy system, demonstration of the multi-market and grid services provision from a multi-energy VPP, and quantification of the energy independence. The case studies showcase the power of the proposed model, especially in quantifying the value of flexibility. It also demonstrates the suitability of the proposed DMES operational model in assessing business cases associated with DER and optimal investment options, which is further demonstrated in Chapter V.

Chapter V. Distributed multi-energy system investment model and business case assessment

This chapter presents the DMES investment model, which is a scenario-based planning model considering long-term uncertainty associated with market prices, and a business case assessment framework. The DMES investment model adopts a so-called roll-out method to identify the deterministic optimal investment plan under different scenarios, while the decision is made with a risk-based decision model, aiming to find the solution with the least worst regret (LWR) across all scenarios. This model is demonstrated with two case studies in the content of NEM.

5.1 Introduction

A Business case is a key to turn an idea into reality, providing a strategic context for any evidence-based decisions [181], [182]. A business illustrates the fundamental logic and quantifies the costs and benefits of any physical and commercial intervention [183]. In the context of DMES, physical intervention includes various elements. That may include investing DER or implementing information and communication technologies (ICT) in order to control and monitor the resources. Commercial intervention may involve participating in markets and providing grid services. Aggregating, coordinating DER using the aggregations concepts such as VPP, microgrids, and ICES, play vital roles in exploiting the flexibility from existing and potential demand-side resources and contributing to the reliability and security of the power system operation. However, developing DER and facilitating

relative implementations of aggregation concepts requires convincing business cases, which requires proper quantifications of the costs and benefits that are associated with the investment through the project life, so as to determine the profitability of the investment. A complete picture of the revenue streams from market participation and grid service provision is essential in assessing the business cases. This requires, firstly, the understanding of the technical characteristics of the resources, and secondly, identifying the potential markets and grid services that are available to DMES, and their commercial agreements. The proper co-optimization model that is able to extract values of flexibility from DMES may also be desired, such as the one developed in Chapter IV. Lastly, the uncertainties coming from the market price variation should be taken into consideration which may impact the economic performances of the DMES from multi-market participation and multi-service provision. In this context, deploying the DMES operation model that is presented in Chapter IV, this chapter introduces a comprehensive framework for establishing the business case of DER and DMES, and an investment model to determining the optimal investment strategies under long-term uncertainty so as to support the relevant business cases of DER and DMES.

5.2 Modeling framework

The modeling framework for business case assessment and investment model is shown in Figure V-1. The first step is data pre-processing, which carries out the techno-economic parameters and price scenarios. The techno-economic parameters include the technical characteristics of technologies, such as efficiency, capacity, and ramping rate, operation costs, investment costs, and discount rate. The

uncertainty of the market price variation is handled adopting a scenario-based approach [184]. In the data pre-processing step, multi-variable price scenarios are defined based on historical data to consider multiple price parameters simultaneously. The techno-economic input and price scenarios are then passed to the optimal operation model that is presented in Chapter IV. The devices' operation, market participation, and grid service provision under different price scenarios are then optimized using the DMES operation model, which are used to determine the operational costs and revenues, providing fundamental information for business case assessment and the optimal planning model. The business case of a project is assessed through several cost benefit analysis (CBA) metrics. CBA is widely used as means to compare the costs and benefits of a given project, so as to provide indicators of whether the project is desirable or not, and to provide the basis for comparing different investment options. In this model, the net present value (NPV) and discounted payback period (DPP) are used as the CBA metrics.

The optimal planning model aims to maximize the NPV over the project horizon under various scenarios, adopting a so-called roll-out method. The input of the optimal planning model includes the multi-variable price scenarios and the operational costs and revenues of various generation mix under all price scenarios. Finally, the investment decision is made based on a risk-based approach, which identifies the investment options with least-worst regret (LWR) across the scenarios.

The cost benefit analysis metrics, optimal planning model, and risk-based decision model are presented in the following sections.

Chapter V. Distributed multi-energy system investment model and business case assessment

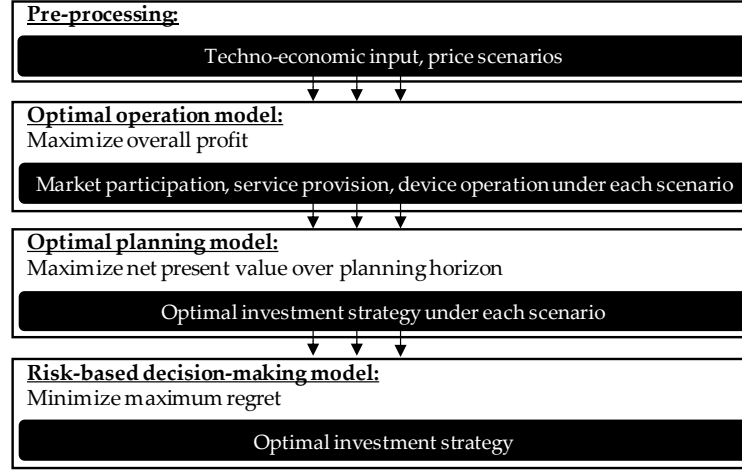


Figure V-1. Investment under uncertainty and business case assessment

5.2.1 Cost benefit analysis metrics

While a variety of criteria can be used to perform CBA, the *time-value of money* principle is chosen to perform CBA, in order to take consideration of inflation and purchasing power. The time-value of money principle assumes that the money has a greater value in the present than the identical amount of money in the future, due to its potential earning capacity. That is, the revenues and costs in the future have less weighted values than the present. By applying a discount factor, the future cash flows are converted to their present value under the time-value of money principle. The CBA may contain uncertain parameters, such as market prices. One way to evaluate the uncertainties is through sensitivity analysis. The sensitivity analysis is undertaken by altering vital parameters in the analysis, which shows the changes in CBA results in response to parameter changes.

The modeling of two CBA metrics using the time-value of money principle, the NPV, and the DPP, are introduced in the following sections.

5.2.1.1 Net present value

The NPV is defined as the cumulated cash flows over the project life discounted to their present value, which can be used to quantify the profitability of the project. In order to calculate NPV, the annual operational profits is firstly calculated, taking into consideration of the annual operational revenue, including the revenue from participating in multiple markets, and operational costs, i.e., the operational costs associated with the operation of devices, market participation, and grid service provision, before discounted the cash flow to the present value.

5.2.1.1.1 Annual operational profits modeling

The annual operational profits consist of two parts, i.e., operational costs, and revenues, and it is defined as the revenues substitute the costs, using equation (V-1):

$$p_s \left(\{u_{y,i,s}\}_{i \in \mathbf{I}} \right) = r_s \left(\{u_{y,i,s}\}_{i \in \mathbf{I}} \right) - c_s \left(\{u_{y,i,s}\}_{i \in \mathbf{I}} \right) \quad (\text{V-1})$$

For all $y \in \mathbf{Y}, s \in \mathbf{S}$.

The annual operational profits $p_s \left(\{u_{y,i,s}\}_{i \in \mathbf{I}} \right)$, operational costs $c_s \left(\{u_{y,i,s}\}_{i \in \mathbf{I}} \right)$, and operational revenue $r_s \left(\{u_{y,i,s}\}_{i \in \mathbf{I}} \right)$, are functions of the units of the technologies $u_{y,i,s}$. The operational costs and operational revenues are calculated based on the devices' operation set points, multi-market participation, and multi-service provision, at each time step (i.e., every five minutes), which are optimized using the DMES multi-market multi-service co-optimization model presented in Chapter IV. A list of the components of operational costs and operational revenues is shown in Table V-1.

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Table V-1. Annual net cash flow components

Components		Description	Unit
<i>Operational costs</i>	Aggregation operational cost	Variable cost of operating the DMES	\$/MW/year
		Fixed cost of operating the DMES	\$/year
	DER operational cost	Variable cost of operating the DER to produce electricity	\$/MWh
		Fixed cost of DER	\$/MW/year
	Energy import cost	Cost of importing energy (e.g., electricity, gas, and hydrogen)	\$/MWh
<i>Operational Revenues</i>	FCAS revenue	Availability payment for being available for providing FCAS	\$/MW/h
	DR revenue	Availability payment for being available to provide DR at the given times	\$/MW
		Activation payment for delivering DR	\$/MWh
	Caps revenue	Availability payment for being available to deliver caps	\$/MW
		Activation payments from selling in the wholesale electricity market when the price exceeds \$300/MWh	\$/MWh
	Energy export	Revenue from exporting energy (e.g., electricity, gas, and hydrogen)	\$/MWh

The operational costs include the operational costs for technologies, energy import costs, and operational costs for aggregation, and is modeled using equation (V-2). The operational costs for technologies (e.g., generator, electrolyzer, etc.), consist of fixed costs which only depend on the sizes of the technologies that are installed, and variable costs which are in proportion to the quantity of the energy output from the technologies. The energy import costs are the cost to import electricity and fuels. The operational costs for aggregation are composed of fixed costs and variable costs which are in proportion of the capacity that is controlled.

$$\begin{aligned}
 c_s \left(\{u_{y,i,s}\}_{i \in \mathbf{I}} \right) = & \sum_{t \in \mathbf{T}} \left(p_{t,s}^- \lambda_{t,s}^{elec-} \Delta t + \sum_{f \in \mathbf{F}} (e_{t,f,s}^- \lambda_{t,f,s}^{fuel-}) \right. \\
 & + \sum_{g \in \mathbf{G}} (p_{t,g,s}^{gen} \gamma_{g,s}^{gen} \Delta t + u_{t,g,s}^{SU} \gamma_{g,s}^{SU} + u_{t,g,s}^{SD} \gamma_{g,s}^{SD}) \left. \right) + \overline{p}_s^{GCP} \lambda_s^{peak} \\
 & + \sum_{i \in \mathbf{I}} u_{y,i,s} \gamma_{i,s}^{fixed} + \gamma_{agg}^{fixed} + c_s^{agg} \gamma_{agg}^{var}
 \end{aligned} \tag{V-2}$$

For $y \in \mathbf{Y}, s \in \mathbf{S}$.

Operational revenue streams include FCAS payment, DR payment, cap contract, and energy export revenue, which are modeled using equation (V-3). More specifically, the FCAS payment refers to the availability payment from participating in various FCAS markets. The DR payment including an upfront payment for being available at the required time, and an activation payment for delivering DR when it is called. The cap payments consist of an upfront availability payment and an activation payment when the wholesale energy price exceeds the agreed strike price. The energy export revenues are the revenues associated with exporting electricity and fuels.

$$\begin{aligned}
 r_s \left(\{u_{y,i,s}\}_{i \in \mathbf{I}} \right) = & \sum_{t \in \mathbf{T}} \left(p_{t,s}^+ \lambda_{t,s}^{elec+} \Delta t + \sum_{f \in \mathbf{F}} (e_{t,f,s}^+ \lambda_{t,f,s}^{fuel+}) \right. \\
 & + \sum_{\chi \in \mathbf{X}} (p_{t,\chi,s}^r \lambda_{t,\chi,s}^r + p_{t,\chi,s}^l \lambda_{t,\chi,s}^l) + p_{t,s}^{cap} \lambda^{cap} \Delta t \\
 & \left. + \omega_{t,s}^{cap} p_{t,s}^{cap} \overline{\lambda}_s^{cap} \right) + p_s^{DR} \lambda_s^{DR} + p_s^{DR} N^{DR} \overline{\lambda}_s^{DR}
 \end{aligned} \tag{V-3}$$

For $y \in \mathbf{Y}, s \in \mathbf{S}$.

5.2.1.1.2 Net present value modeling

The NPV at year N_y , npv_{N_y} , is calculated using equation (V-4), which is based on the annual operational profits $p_s(\{u_{y,i,s}\}_{i \in I})$ at each year under scenario s that is calculated using equations (V-1)-(V-3), the number of units of technologies at each year under scenario s , $u_{y,i,s}$, the investment cost of technology i under scenario s , $c_{i,s}$, and the discount rate r .

$$npv_{N_y,s}(\{u_{y,i,s}\}_{i \in I}) = \sum_{y=1}^{N_y} \left\{ \sum_{i \in I} \frac{1}{(1+r)^y} (p_s(\{u_{y,i,s}\}_{i \in I}) - c_{i,s}[u_{y,i,s} - u_{y-1,i,s}]) \right\} \quad (V-4)$$

A positive NPV often indicates that the cash inflows are larger than cash outflows, thus it is worth to invest. On the contrary, a negative NPV means it is not profitable to make the investment.

5.2.1.2 Discounted payback period modeling

The DPP is used to calculate the amount of time that is needed to return the investment, which can be used to evaluate the feasibility and profitability of a project. The DPP is defined as the time required to recover the original investment costs considering the time value of money. DPP is calculated as the period of which the NPV is zero or positive. That is, the DPP, $\hat{y}$, is the smallest value such that the following inequality holds for all $y_s \geq y_s^{DPP}$:

$$npv_{y,s}(\{u_{y,i,s}\}_{i \in I}) \geq 0 \quad (V-5)$$

5.2.2 Optimal planning model

5.2.2.1 Problem formulation

The expansion of any power system includes decisions in the realm of transmission and generation assets. In the case of the DMES, it is assumed that the capacity of the link between the neighborhood level and the rest of the system is kept constant throughout the project life. Keeping that capacity constant will drive the investment possibilities, due to the inability to transfer or sell more products, for instance, energy and FCAS, to the system (see constraint (IV-68)-(IV-70)).

Finding the optimal investment options for DMES can be formulated as a Markov Decision Process (MDP) [185]. The MDP is often used in decision-making problems that aim to find the optimal policy to achieve the maximum cumulated rewards. The investment problem of a DMES is solved over the planning horizon, i.e., N_y . At each year y , there is an option to take an action to invest in a set of candidate units. The state at each discrete time y is denoted as $u_{i,y,s}$, which is the number of candidate units that are installed in DMES for technology i , at year y , under scenario s . The reward, $R_{y,s}(\{u_{y,i,s}\}_{i \in I})$, includes two parts, i.e., the annual net profit, $p_s(\{u_{y,i,s}\}_{i \in I})$ that is a function of the state $u_{y,i,s}$, and the investment cost that is associated with the action that is taken at each state, i.e., the new units that are installed at each state. In another word, the reward can be seen as the annual cash flow which is defined as the annual net profit minus the investment cost, i.e., $R_{y,s}(\{u_{y,i,s}\}_{i \in I}) = p_s(\{u_{y,i,s}\}_{i \in I}) - \sum_{i \in I} c_{i,y} u_{y,i,s}$. The reward is discounted with the factor γ^y , which is a function of the discount rate, i.e., $\gamma = \frac{1}{1+r}$. The value of the given investment policy Q_s^π is defined as the cumulated discounted rewards over

the horizon, i.e., N_y , i.e., $Q_s^\pi = \sum_{y=1}^{N_y} \gamma^y R_{y,s}(\{u_{y,i,s}\}_{i \in \mathbf{I}})$. Let i donates to the candidate units, the objective of the investment model is to find the optimal policy so as to maximize the value, which can be formulated as follows:

$$\max_{u_{y,i,s}} \sum_{y \in \mathbf{Y}} \left\{ \sum_{i \in \mathbf{I}} \frac{1}{(1+r)^y} \left(p_s(\{u_{y,i,s}\}_{i \in \mathbf{I}}) - c_{i,s}[u_{y,i,s} - u_{y-1,i,s}] \right) \right\} \quad (\text{V-6})$$

The optimization problem is subject to the following constraints:

$$u_{y,i,s} \in \mathbb{Z}_{[0, \bar{u}_i]}, \forall i \in \mathbf{I}, \forall y \in \mathbf{Y}, \forall s \in \mathbf{S} \quad (\text{V-7})$$

$$u_{1,i,s} \leq \theta_i, \forall i \in \mathbf{I}, \forall s \in \mathbf{S} \quad (\text{V-8})$$

$$0 \leq u_{y,i,s} - u_{y-1,i,s} \leq \theta_i, \forall i \in \mathbf{I}, \forall y \in \mathbf{Y} \setminus \{1\}, \forall s \in \mathbf{S} \quad (\text{V-9})$$

$$u_{y,i,s} \leq \bar{\theta}_i, \forall i \in \mathbf{I}, \forall y \in \mathbf{Y}, \forall s \in \mathbf{S} \quad (\text{V-10})$$

The annual net profits, $p_s(\{u_{y,i,s}\}_{i \in \mathbf{I}})$ is modeled using the DMES operation optimization model and it is subject to the operation constraints (IV-4)-(IV-71) that are presented in the previous Chapter IV. At each year, the available units of candidate technology i that can be installed is limited by θ_i , using constraints (V-8)-(V-9). Moreover, the decision variable $u_{y,i,s}$ is also constrained by the maximum number of units for candidate technology i that can be installed in the system, $\bar{\theta}_i$, using constraint (V-10).

Even for a small size DMES, the size of the resulting problem for the investment process of tens of years and a few investment alternatives can be rather large. In this context, various approaches can be used to address the problems of dimensionality that can lead to a slow search of the branch and cut algorithm. Some of

the approaches involve linearizing the problem to use nested benders decomposition, column generation, progressive hedging, among others. In this case, and given the characteristics of the problem, a roll-out method is proposed to solve the investment problem.

5.2.2.2 Property of the annual profits

In order to investigate the property of the annual operational profits, $p_s(\{u_{y,i,s}\}_{i \in \mathbf{I}})$, a test case is carried out. The test case is set up with a multi-energy VPP consisting of RES, including a 30 MW solar farm and a 60 MW wind farm, a hydrogen-based OCGT with a capacity of 10 MW, an electrolyzer, and a BESS. The electrolyzer and the BESS are selected as the candidate technologies. Different sizes of electrolyzer and BESS, varying from 0 MW to 625 MW, are tested. The electricity import/export at the GCP is set to be 108 MVA, assuming to be equivalent to 1.2 times of the sum of the wind farm and solar farm maximum generation capacity. The VPP is considered to participate in multiple markets including the wholesale electricity market, contingency FCAS markets, and hydrogen market while providing FFR for the 30 MW solar farm within the VPP to fulfill its FFR obligation.

The annual operational profits for various sizes of electrolyzer and BESS are shown in Figure V-2. The annual profits according to various sizes of electrolyzer and BESS are also illustrated in Figure V-3 and Figure V-4 respectively. The annual operational profits, $p_s(\{u_i(y)\}_{i \in \mathbf{I}})$, can be seen as a submodular set function, which has the property that the difference in the incremental value of the annual operational profits decreases as the size of one of the technologies increases. That is because when the sizes of the technologies increase, the network constraints become active. Thus, the electricity import/export and FCAS commitments (see constraints

(IV-68)-(IV-70) in Chapter IV) are constrained, which leads to decreases in the incremental value of the annual operational profits.

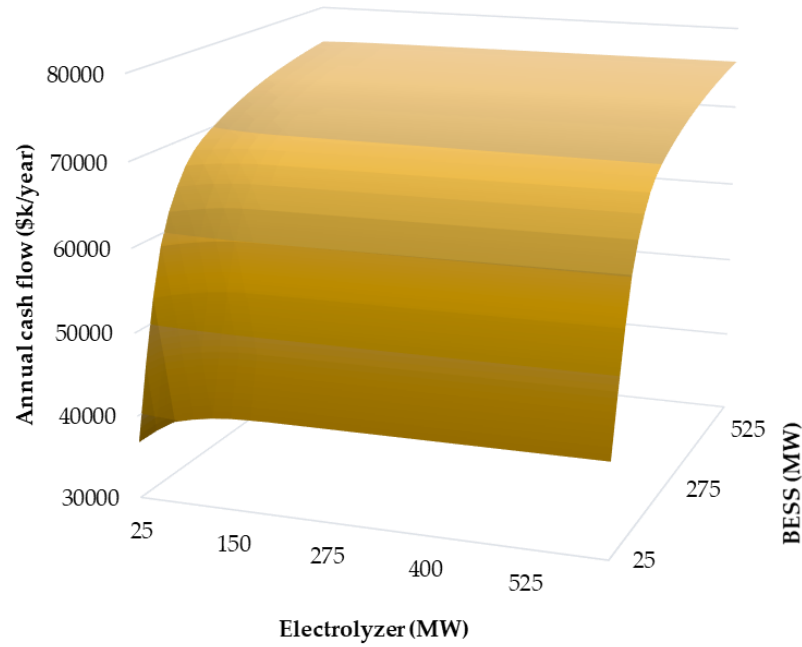


Figure V-2. Annual operational profit of the test VPP with various sizes of the electrolyzer and BESS

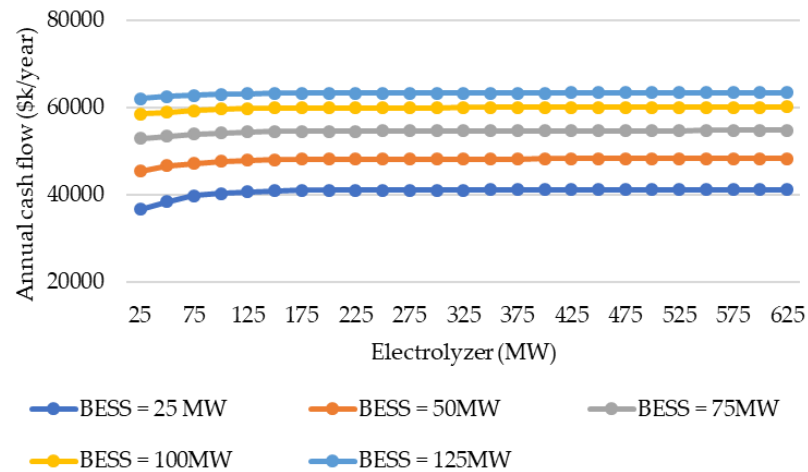


Figure V-3. Annual operational profits of the test VPP with regards to the size of the electrolyzer

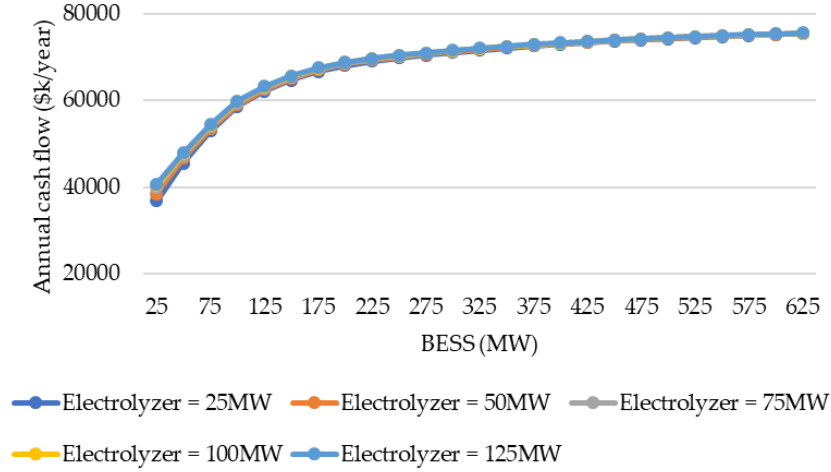


Figure V-4. Annual operational profits of the test VPP with regards to the size of BESS

5.2.2.3 Roll-out method for scenario-based investment planning

From the previous exercises, it can be seen that when the capacity linking the DMES to the rest of the system is constant throughout the project life, the net operational profits $p_s(\{u_{y,i,s}\}_{i \in \mathbf{I}})$, is positive, bounded, and monotone nondecreasing functions of its arguments, i.e., the units of the candidate technologies at each year, $u_{y,i,s}$. Moreover, $\frac{1}{1+r} \in (0,1)$, and θ_i , and $\bar{\theta}_i$ are positive numbers. The decision variables $u_{1,i,s}, \dots, u_{N_y,i,s}$ are independent of $u_{1,j,s}, \dots, u_{N_y,j,s}$, where $j \in \mathbf{I} \setminus \{i\}$. The objective function (V-6) can be rewritten as (V-11), which is subject to constraints (V-7)-(V-10):

$$\max_{u_{y,i,s}} \sum_{i \in \mathbf{I}} \left\{ \sum_{y \in \mathbf{Y} \setminus \{N_y\}} \frac{1}{(1+r)^y} \left[p_s(\{u_{y,i,s}\}_{i \in \mathbf{I}}) - \left(\frac{r}{1+r} \right) c_{i,s} u_{y,i,s} \right] + \frac{1}{(1+r)^{N_y}} \left[p_s(\{u_{y,i,s}\}_{i \in \mathbf{I}}) - c_{i,s} u_{N_y,i,s} \right] \right\} \quad (\text{V-11})$$

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The discount factor, i.e., $1/(1+r)$, is less than one, which decreases exponentially with year y . Thus, the component $\left[p_s\left(\{u_{N_y,i,s}\}_{i \in \mathbf{I}}\right) - c_{i,s}u_{N_y,i,s}\right]/(1+r)^{N_y}$, which is only related to the state of the end of the planning horizon N_y , might be comparably small depending on the value of N_y and the discount rate r . Thus, here we only focus on the first term of the objective function (V-11), which is expressed as below:

$$\max_{u_{y,i,s}} \sum_{i \in \mathbf{I}} \left\{ \sum_{y \in \mathbf{Y} \setminus \{N_y\}} \frac{1}{(1+r)^y} \left[p_s\left(\{u_{y,i,s}\}_{i \in \mathbf{I}}\right) - \left(\frac{r}{1+r}\right) c_{i,s}u_{y,i,s} \right] \right\} \quad (\text{V-12})$$

By analyzing the construction of $Q_s^{\pi'} = \sum_{i \in \mathbf{I}} \left\{ \sum_{y \in \mathbf{Y} \setminus \{N_y\}} \frac{1}{(1+r)^y} \left[p_s\left(\{u_{y,i,s}\}_{i \in \mathbf{I}}\right) - \left(\frac{r}{1+r}\right) c_{i,s}u_{y,i,s} \right] \right\}$, we propose the following solution of (V-12). Let $\widehat{u}_{i,s}$ be the largest integer such that the following inequalities hold for all $u_{i,s} \leq \widehat{u}_{i,s}$:

$$\frac{\partial p\left(\{u_{y,i,s}\}_{i \in \mathbf{I}}\right)}{\partial u_{y,i,s}} - \left(\frac{r}{1+r}\right) c_{i,s} \geq 0 \quad (\text{V-13})$$

$$u_{y,i,s} \leq \bar{\theta}_i \quad (\text{V-14})$$

Let $u_{y,i,s}^*, y \in \mathbf{Y}$ be the solution to (V-12). The optimal policy is given by:

$$u_{1,i,s}^* = \dots = u_{k_s,i,s}^* = \theta_{i,s}, \forall i \in \mathbf{I}, \forall s \in \mathbf{S} \quad (\text{V-15})$$

$$u_{k_s+1,i,s}^* = \min(\theta_{i,s}, \widehat{u}_{i,s} - k\theta_{i,s}), \forall i \in \mathbf{I}, \forall s \in \mathbf{S} \quad (\text{V-16})$$

$$u_{j,i,s}^* = 0, \forall i \in \mathbf{I}, \forall j \in \mathbf{Y} \setminus \{1, \dots, k_s + 1\}, \forall s \in \mathbf{S} \quad (\text{V-17})$$

Where $k_s = \min(N_y - 1, \min(\widehat{u}_{i,s}, \bar{\theta}_{i,s})/\theta_{i,s})$. That is, the DMES should invest a candidate unit at the maximum speed until the number of installed candidate units

reaches $\hat{u}_t$. This can be seen as a special case of a family of methods of so-called roll-out methods. The optimal planning model provides the optimal investment plan for each scenario, resulting in a set of investment strategies.

5.2.3 Risk-based decision-making model

The optimal planning model that is presented in section 5.2.2.3 finds the optimal investment strategy under each price scenarios, resulting in a set of solutions, i.e., $u_{y,i,c}$. The decision is then made adopting a risk-based approach based on LWR. The regret is defined as the differences between the NPV of investment strategy $u_{y,i,c}$ under scenario s and the maximum NPV that can be achieved under scenario s (i.e., when the optimal investment strategy $u_{y,i,s}^*$ is chosen). The maximum regret of an investment strategy $u_{y,i,c}$ under all scenarios is defined as below.

$$R(u_{y,i,c}) = \max \left\{ npv_{N_y,s} \left(\{u_{y,i,s}^*\}_{i \in I} \right) - npv_{N_y,s} \left(\{u_{y,i,c}\}_{i \in I} \right) \right\} \quad (V-18)$$

The risk-based decision model aims to find the solution which has the least maximum regret $R(u_{y,i,c})$:

$$\min \{R(u_{y,i,c})\} \quad (V-19)$$

5.3 Applications

Two case studies with distinct set-ups (i.e., generation mix, demand, locations, and market participations) are carried out to demonstrate the proposed modeling framework for business case assessments. More specifically, the first case study

aims to assess the feasibility and business cases of a real-world urban VPP application. The second case study demonstrates the optimal investment options of a multi-energy VPP including hydrogen-based devices, RES, and storages.

5.3.1 Case study I – feasibility study and business case assessment of an urban virtual power plant

In order to demonstrate the feasibility and business case of operating DER in urban areas as a VPP, a real-world case study is conducted here with reference to the University of Melbourne (UoM) Fishermans Bend (FB) campus, which is located in Melbourne, VIC, Australia. The UoM FB campus is designed to have DER, consisting of PV, gas generator, BESS, and flexible loads (i.e., controllable load from HVAC systems for space heating and cooling). This case study aims to analyze the economic feasibility of developing a VPP using the proposed DER within the FB campus, which is based on the work published in [77].

5.3.1.1 Demand analysis

The estimated demand and flexible loads for the UoM FB campus are shown in Figure V-5. The UoM FB campus is predicted to have a peak load of 14 MW, with annual electricity consumption of 65 GWh. The electricity demand mainly comes from the use of offices, conference spaces, and laboratories. The flexible load accounts for around 5% of annual electricity consumption of the FB campus, i.e., 3.5 GWh, and has a peak load of 3 MW.

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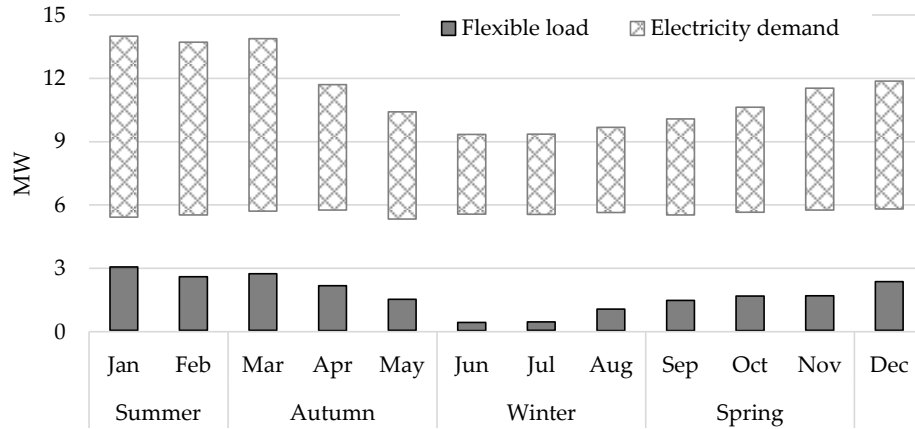


Figure V-5. UoM FB demand and flexible loads [77]

The half-hourly electricity demand profile of the FB campus is estimated based on the normalized electricity demand profiles of the UoM Parkville campus, while the PV generation is calculated based on the solar irradiances that are available at the Bureau of Meteorology (BoM) [154]. The half-hourly demand profiles and PV generation for a winter week and a summer week is shown in Figure V-6. It can be seen that the electricity demand and flexible loads are higher in the summer week than in the winter week, due to the high space cooling demand. The PV generation during the summer is also higher than the winter week for most of the days, as results of higher solar irradiances experienced during the summer. The flexible loads during the winter week are minor as part of the space heating demand is fulfilled by gas. Moreover, higher electricity demand is observed during the weekdays than weekends. Last but not least, the electricity demand also concentrated during the daytime, i.e., 9.00h to 19.00h.

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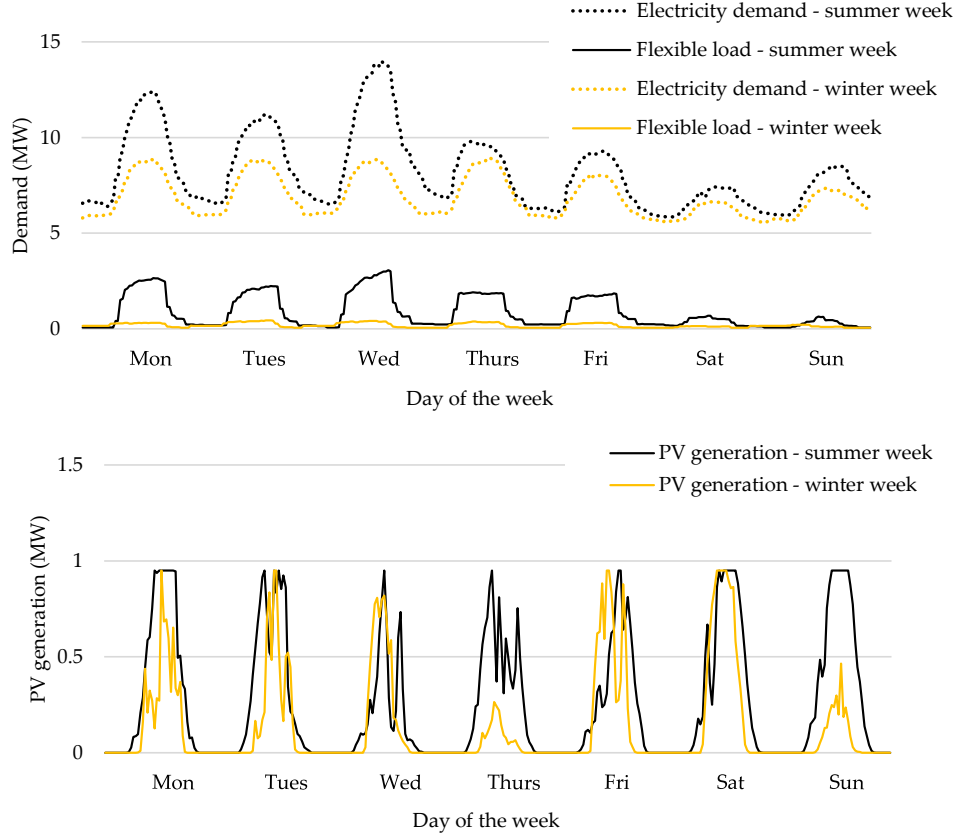


Figure V-6. Half-hourly demand profiles (top) and PV generation (bottom) for a summer week and a winter week [77]

5.3.1.2 Market information and description

The proposed VPP is designed to participate in multiple markets, including the electricity market, FCAS markets, DR market, and cap contract market. The VPP imports electricity using a retail tariff that is contracted with the retailer and exports electricity using the feed-in tariff, which is presented in Table V-2. The retail tariff consists of energy charges, network charges, industry charges, metering charges. The retail tariff includes both variable charges which depend on the usage of the electricity (i.e., peak and off-peak energy charges and network charges, and industry charges) and the peak load of the electricity demand (i.e., rolling demand charge) and fixed charges which are charged on a daily basis.

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Table V-2. Electricity tariff and feed-in tariff (including GST) [77]

Description		Price	Unit
Energy charges	Daily charge	0.90	\$/day
	Off-peak (7.00h-23.00h)	0.03	\$/kWh
	Peak (all other time)	0.05	\$/kWh
Network charges	Daily charge	15.37	\$/day
	Off-peak (7.00h-23.00h)	0.02	\$/kWh
	Peak (all other time)	0.03	\$/kWh
	Rolling demand	8.10	\$/kVA/month
Other industry charges		0.01	\$/kWh
Metering charges		2.52	\$/day
Solar feed-in tariff		-0.10	\$/kWh

The FCAS prices are based on VIC five-minute contingency FCAS market prices taken from AEMO [80], which are shown in Figure V-7. In general, the prices for contingency raise FCAS markets are higher than the prices for lower contingency FCAS markets. Moreover, the fast raise FCAS and the delayed lower FCAS have the highest value among all contingency raise FCAS markets and contingency lower FCAS markets, respectively.

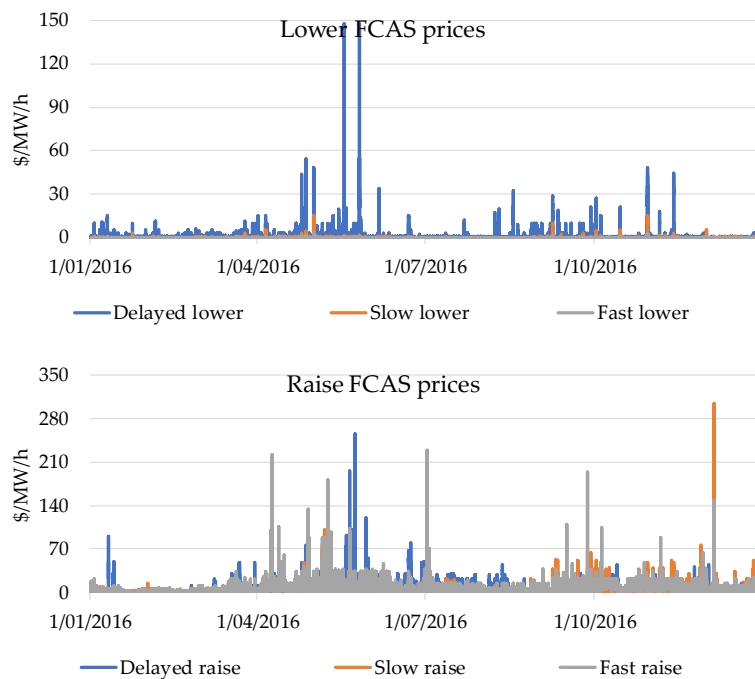


Figure V-7. VIC contingency FCAS prices in the year of 2016

The key parameters of the DR market are presented in Table V-3, based on the AEMO/ARENA demand response trial of summer 2018 [186]. The DR is required to be available from 10.00h to 22.00h on weekend during the summer. The maximum activation frequency of DR is 10 times per year, with durations that are not longer than 4 hours. The payment includes the upfront payment for availability and additional payment for activation.

Table V-3. Key parameters of the DR program [77]

Notification time:	10 minutes or 60 minutes
Activation frequency	10 activations per year, starting 1 December
Activation duration	4 hours
Availability period:	10.00h to 22.00h on the business day
Payment for availability:	20,000 \$/MW
Payment for usage:	500 \$/MWh, up to a maximum of 40 hours per year

The cap market prices are based on the quarterly prices of VIC \$300 cap future that is traded on ASX [179], and an example of the quarterly cap contract prices of 2019 is shown in Figure V-8. It can be seen that the cap price for the first quarter, i.e., from January to March, is more substantial than other quarters, as the energy spike is more likely to happen during the summer. This is because the high demand periods are often associated with high temperatures and comparatively low wind generation.

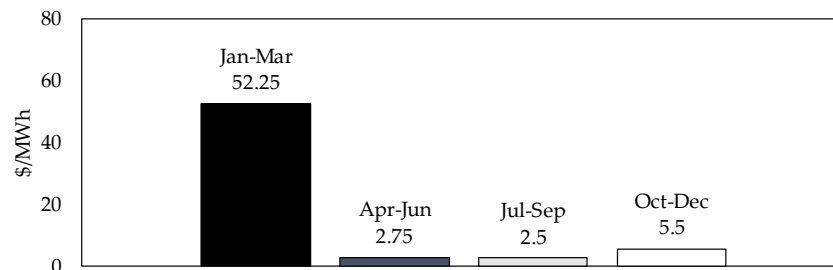


Figure V-8. Quarterly cap contract prices [77]

5.3.1.3 Investment costs and operational costs

The technology investment costs and operational costs that are considered in the case study are presented in Table V-4 and Table V-5, respectively. The investment costs include the investment cost of PV, BESS, gas generator and hardware required for VPP set-up. The operational costs consist of variable costs and fixed costs for PV, BESS, gas generator and VPP [187].

Table V-4. Investment costs of DER and VPP [77]

Technology	Investment cost	Unit
PV	2,750	\$/kW
BESS	1,676	\$/kW
Gas generator	900	\$/kW
VPP	1,045	\$/device

Table V-5. Operational costs of DER and VPP [77]

Technology	Operational cost		Unit
PV	Variable cost	-	\$/kWh
	Fixed cost	28	\$/kW/year
BESS	Variable cost	-	\$/kWh
	Fixed cost	-	\$/kW/year
Gas generator	Variable cost	0.08	\$/kWh
	Fixed cost	21.3	\$/kW/year
VPP	Variable cost	33	\$/kW _{controlled} /year
	Fixed cost	11,550	\$/year

5.3.1.4 Test cases descriptions

Three different test cases are designed and modeled in order to assess the economic performance of operating the FB campus as a VPP, namely, test case I.BAU, test case II.DER, and test case III.VPP. More specifically:

- Test case I.BAU: this test case represents a business as usual (BAU) operation. Under a BAU operation, FB campus does not have any DER installed, while the FB campus only imports electricity using the electricity tariff that is contracted with the retailer, without participating in

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any other markets. This BAU operation test case is used as a benchmark result of other test cases.

- Test case II.DER: in test case II.DER, it is assumed that the proposed DER is installed. However, the DER is not centrally controlled and do not participate in any markets. The FB campus imports electricity using retail tariffs.
- Test case III.VPP: in this test case, the FB campus, together with the proposed DER, are operated as a VPP, and actively participates in multiple markets, i.e., electricity tariff, FCAS, DR, and caps.

The details of the three test cases are listed in Table V-6. For test case II.DER and test case III.VPP, different sizes of gas generator, and BESS are analyzed, i.e., varying from 0 to 4 MW with a step size of 0.5 MW. It is assumed that the maximum size of the BESS and gas generators are 4 MW, while no limit on the maximum capacity that can be installed in each year.

The BESS energy capacity is 1.6 times its maximum charge/discharge power, with a round trip efficiency of 90%. Moreover, for test case II.DER and test case III.VPP, the PV is sized to 1.1 MW, which is assumed that 25% of the rooftop area is utilized. The gas generator has an activation delay of 20 seconds, while the ramping up/down time for all other technologies, i.e., PV, BESS, and flexible load is less than 1 second.

Table V-6. Test cases description [77]

Test cases	PV (MW)	Gas generator (MW)	BESS (MW)	Market participation
I.BAU	0	0	0	Electricity tariff
II.DER	1.1	0~4	0~4	Electricity tariff
III.VPP	1.1	0~4	0~4	Electricity tariff, FCAS, DR, caps

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5.3.1.4.1 Price sensitivity scenarios

In order to take into account the wholesale market price variations, the case study is also conducted over different electricity price scenarios and FCAS price scenarios. Nine price sensitivity scenarios are modeled, which are a combination of low, medium, and high electricity price scenario and low, medium, and high FCAS price scenario. The details of nine price sensitivity scenarios are illustrated in Table V-7.

In terms of electricity price scenarios, the energy cost component (see Table V-2), which is a reflection on the wholesale electricity prices, varies from 80% to 120% of current prices, while other components, such as network charges, other industry charges, and metering charges, remains the same. More specifically, the *low electricity price scenario* has an energy cost that accounts for 80% of the current energy costs, the *medium electricity price scenario* remains the same as the current tariff, while the *high electricity price scenario* has an energy cost that is 120% of the current energy costs.

In terms of FCAS price scenarios, the five-minute VIC FCAS prices of 2016 are considered as the *low FCAS price scenario*, while the *medium FCAS price scenario* and *high FCAS price scenario* are 120% and 140% of the low FCAS price scenario, respectively.

Table V-7. Price sensitivity scenarios

	A. low electricity price scenario	B. medium electricity price scenario	C. high electricity price scenario
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i. low FCAS price sce- nario	Price scenario A-i: low electricity price scenario, low FCAS price scenario	Price scenario B-i: medium electricity price scenario, low FCAS price scenario	Price scenario C-i: high electricity price scenario, low FCAS price scenario
ii. medium FCAS price sce- nario	Price scenario A-ii: low electricity price scenario, medium FCAS price scenario	Price scenario B-ii: medium electricity price scenario, me- dium FCAS price sce- nario	Price scenario C-ii: high electricity price scenario, medium FCAS price scenario
iii. high FCAS price sce- nario	Price scenario A-iii: low electricity price scenario, high FCAS price scenario	Price scenario B-iii: medium electricity price scenario, high FCAS price scenario	Price scenario C-iii: high electricity price scenario, high FCAS price scenario

5.3.1.5 Results and discussion

The electricity bill breakdown for test case I.BAU under three electricity price scenarios are presented in Table V-8. As in test case I.BAU, the FB campus does not participate in any markets except importing electricity from the retailer, the total electricity bill is equivalent to its annual net cost. It can be seen that the 20% of reduction in the energy cost component (i.e., low electricity price scenario) results in a 7% of reduction in the annual electricity bill, while the 20% increment in the energy cost component (i.e., high electricity price scenario) results in a 7% increment in the annual electricity bill.

Table V-8. Breakdown of electricity bill of scenario I.BAU [77]

Electricity price sce- nario	Variable charge (\$)			Fixed charge (\$)			Peak de- mand charge (\$)	Total (\$)
	Energy charges	Network charges	Other indus- try charges	Energy daily charges	Meter- ing daily charges	Network daily charges		
Low electric- ity price sce- nario A-i, A-ii, A-iii	1,956,344	1,675,160	941,484	330	918	5,609	1,124,738	5,704,583

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Medium electricity price scenario B-i, B-ii, B-iii	2,445,429	1,675,160	941,484	330	918	5,609	1,124,738	6,193,669
High electricity price scenario C-i, C-ii, C-iii	2,934,515	1,675,160	941,484	330	918	5,609	1,124,738	6,682,755

The cost savings of test case II.DER, with 1.1 MW of PV, various sizes of the gas generator and BESS, under three electricity price scenarios, compared with test case I.BAU are illustrated in Figure V-9. As test case II.DER does not participate in FCAS, DR, nor cap markets, the cost savings are the same across three FCAS price scenarios under the same electricity price scenario. The cost savings are mainly from shifting electricity import periods from high price periods to low price periods using BESS and reduce the peak demand using BESS and gas generator. As the gas generator has a relatively high operational cost, it is only operated to reduce the peak demand so as to reduce the rolling demand charge (see Table V-2.). It can be seen that the economic benefits of test case II.DER is very limited, which only account for 2% to 5% of the annual electricity bill of test case I.BAU.

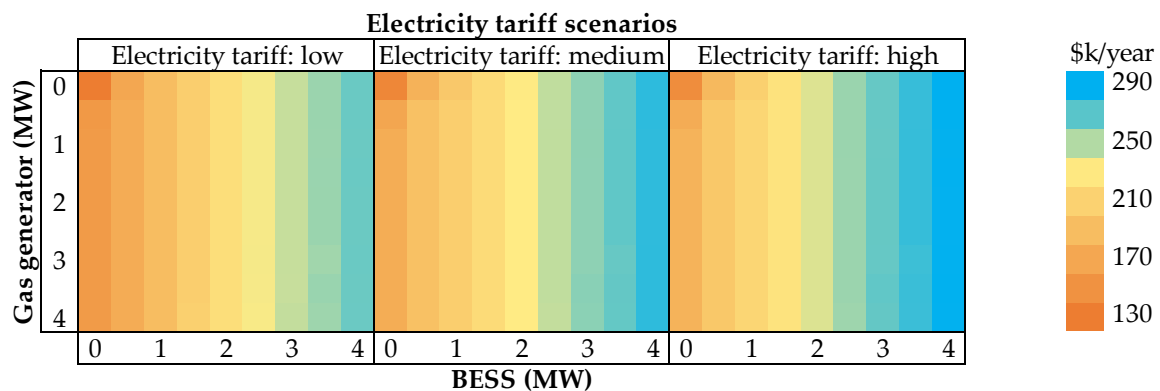


Figure V-9. Cost savings of test case II.DER with 1.1 MW of PV, various sizes of the gas generator, and various sizes of BESS, relative to test case I.BAU, under three electricity price scenarios [77]

The cost savings of test case III.VPP, with 1.1 MW of PV, and various sizes of the gas generator and BESS, compared with test case I.BAU, are shown in Figure 168

V-10. Under test case III.VPP, the VPP participates in electricity, FCAS, DR, and cap markets. In addition to shifting electricity imports from high price periods to low price periods and reduce the peak demand, the economic benefits also come from multiple market participation. It can be seen that substantial cost savings, i.e., a maximum cost-saving accounting for 34% of the annual electricity bill of test case I.BAU, can be achieved. Moreover, cost savings are more sensitive to the FCAS price rather than the electricity price. That is, more substantial changes can be observed when comparing the price sensitivity scenarios with the same electricity price scenario and different FCAS price scenarios, while only minor differences can be found when comparing the price sensitivity scenarios with the same FCAS price scenarios and different electricity price scenarios.

This trend is further illustrated in Figure V-11, which shows the breakdown of the cost savings of test case III.VPP with 1.1 MW of PV, 1 MW of gas generator, and 1 MW of BESS, compared with test case I.BAU, under nine price sensitivity scenarios. The negative numbers represent increases in the costs or decreases in the revenue, while the positive numbers represent decreases in the costs or increases in the revenue. The cost savings on electricity bills only account for 22% to 28% of the total cost savings, while the majority of the cost savings come from FCAS, DR and cap markets participation. This is because the ability of VPP to alter its electricity import and reduce its peak demand is limited by its generation resources, especially the BESS. Thus, it can be concluded that the VPP operation may be considered to be robust against electricity price variation¹⁶.

¹⁶ Different conclusions might be drawn when the VPP trades electricity using the wholesale electricity prices.

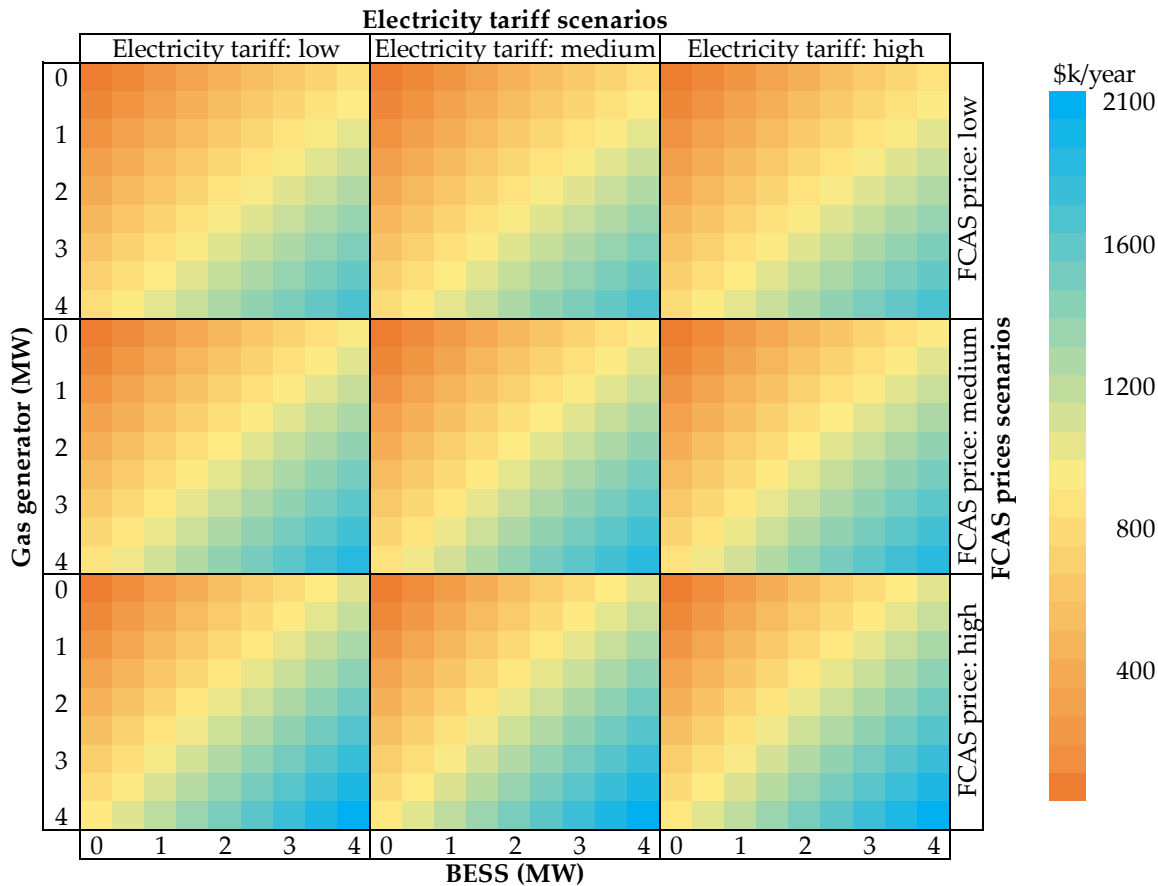


Figure V-10. Cost savings of test case III.VPP, with 1.1 MW of PV, various sizes of the gas generator, and various sizes of BESS, relative to test case I.BAU, under nine price sensitivity scenarios [77]

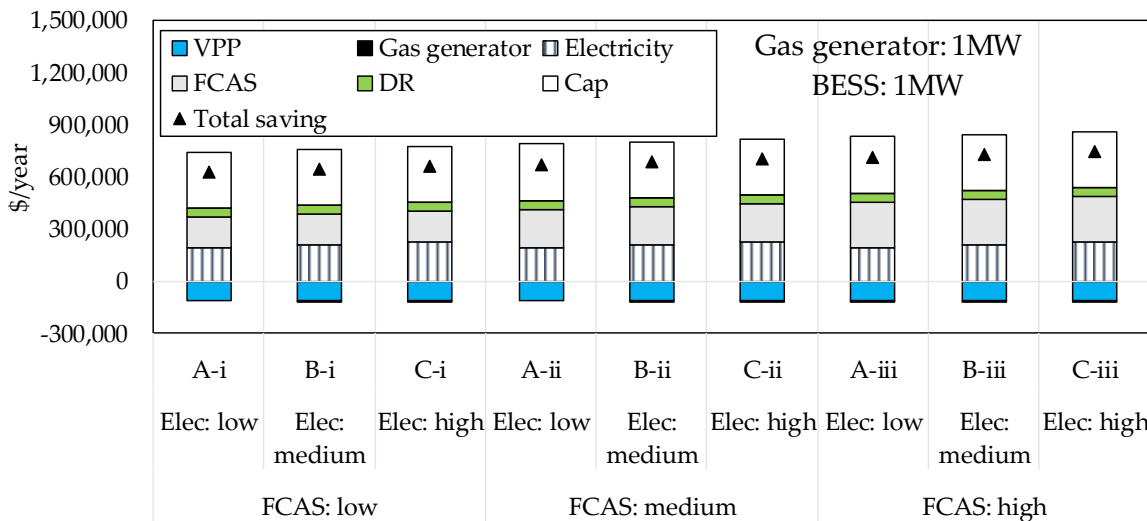


Figure V-11. Breakdown of cost savings and total savings of test case III.VPP, with 1.1 MW PV, 1 MW of gas generator, 1 MW of BESS, relative to test case I.BAU, under nine price sensitivity scenarios [77]

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The DPP of the DER and VPP set-up are shown in Figure V-12, which are calculated based on the cost savings of test case III.VPP compared with test case I.BAU, and a discount rate of 8.25%. White blocks in Figure V-12 means that the DPP for this specific technology combination and price sensitivity scenario is greater than 30 years. For most of the cases, acceptable DPP can be achieved, i.e., under 12 years. For all price sensitivity scenarios, the DPP share a similar trend, i.e., the DPP decrease when the size of technologies increases, within the test range, i.e., 0 MW to 4 MW. Thus, it can be concluded that the investment decisions of the DER may be robust against electricity and FCAS price variations.

On the contrary, without participating in multiple markets, i.e., test case II.DER, the investment of DER will not be paid back within their life spans under all price sensitivity scenarios for all sizes of the gas generator and BESS. This is calculated based on the cost savings of test case II.DER compared with test case I.BAU, and a discount rate of 8.25%.

The DPP of the VPP set-up, which is calculated based on the cost savings of test case III.VPP compared with test case II.DER, is under one year across all scenarios when the VPP has the gas generator and/or BESS installed. This result indicates clear financial viability of operating DER as a VPP and participate in multiple markets.

With regards to the investment strategy, in this particular case, the sizes of BESS and gas generator are mainly constrained by the maximum capacity that can be installed in the VPP, which may be a result as the financial budget or the available space for the proposed technologies, i.e., 4 MW for both technologies. The

results show that the optimal investment strategy is to invest 4 MW of BESS and 4 MW of gas generator, at the beginning of the project.

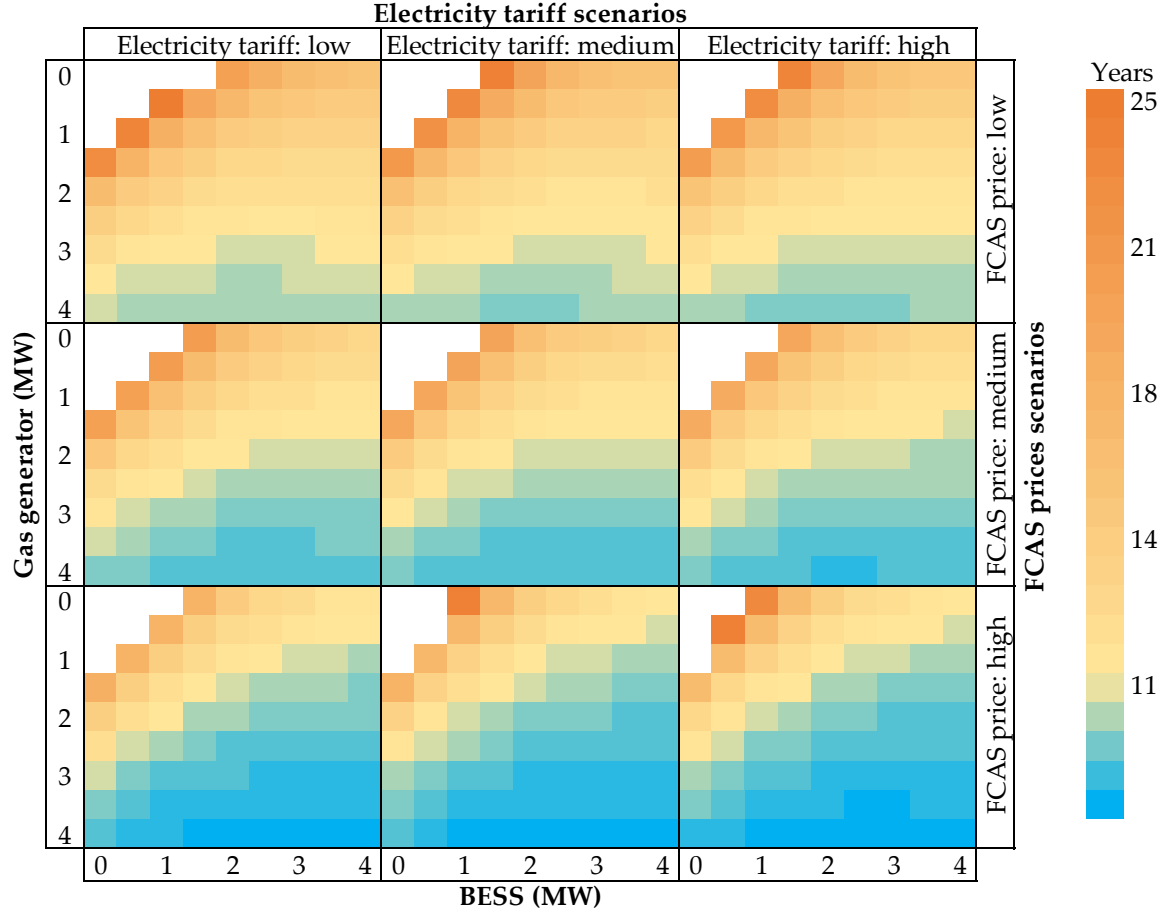


Figure V-12. DPP of DER and VPP set-up (test case III.VPP with 1.1 MW of PV, various sizes of the gas generator, and various sizes of BESS, relative to test case I.BAU, under nine price sensitivity scenarios) [77]

5.3.2 Case study II – optimal investment for an integrated renewable energy resources, electricity, hydrogen virtual power plant

This case study aims to find the optimal investment options for an integrated RES, electricity and hydrogen VPP, using the proposed investment model detailed in section **Error! Reference source not found..** The proposed VPP is designed to have similar set-ups with the VPP presented in section 4.3.2. That is., the VPP contains a 66 MW wind farm, a 15 MW PV farm, and a 10 MW of hydrogen-based

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OCGT. An alkaline electrolyzer together with hydrogen storage and a BESS are considered as the candidate technologies, while their techno-economic parameters are shown in Table V-9. The alkaline electrolyzer has a maximum input power of 5 MW and a COP of 0.75, coupled with a 65 MWh hydrogen storage. The investment cost for the alkaline electrolyzer is assumed to be 1347 \$/kW [188], while it is set to 33 \$/kWh for the bulk hydrogen storage, based on [188]. The fixed operational and maintenance cost for electrolyzer is assumed to be 28 \$/kW/year, which accounts for 7% of the capital cost of the hydrogen storage [188], while the fixed operational cost for bulk hydrogen storage is 2.38 \$/kW/year [188].

The BESS has a maximum charge/discharge power output of 5 MW, with an 8 MWh maximum energy content. The round-trip efficiency is 0.9. The capital cost of BESS is assumed to be 1,676 \$/kWh.

Table V-9. techno-economic parameters for technologies

	Electrolyzer	Bulk hydrogen storage	BESS
Capacity	5,000 kWe	65,000 kWh	5,000 kWe/8,000 kWh
COP	0.7	-	0.9
Investment cost	1,347 \$/kWe	33 \$/kWh	1,676 \$/kWe
Operational cost	28 \$/kW/year	2.38 \$/kWh/year	-
Lifespan	40 years	40 years	15 years

The VPP participates in wholesale electricity, contingency FCAS, and provide FFR obligations of the internal solar farm. The environmental data for RES generation, market prices time-series for wholesale electricity and FCAS, hydrogen export prices, FFR requirement, and the network limit can be found in section 4.3.2.

5.3.2.1 Price sensitivities

Nine price scenarios are conducted to take into consideration of the variability of the wholesale electricity prices and FCAS prices, including three different electricity price scenarios and three FCAS price scenarios, namely, low, medium, and high electricity/FCAS price scenarios. The wholesale electricity prices and FCAS prices of SA in the year of 2017 are set as the base case, i.e., medium price scenarios. The “low” scenarios account for 80% of the medium price scenarios, while the “high” scenarios account for 120% of the medium price scenarios. The wholesale electricity prices for all scenarios are limited to be within the market price cap, i.e., 14,200 \$/MWh, and market floor price, i.e., -1,000 \$/MWh [189].

It is assumed that the probabilities are 60%, 20%, and 20% of having medium, high, and low FCAS or electricity prices, respectively. The probability of the multi-variable sensitivity price scenarios is presented in Table V-10.

Table V-10. Probability of multi-variable sensitivity price scenarios

	Low FCAS price	Medium FCAS price	High FCAS price
Low electricity price	4%	12%	4%
Medium electricity price	12%	36%	12%
High electricity price	4%	12%	4%

5.3.2.2 Annual operational profit

The annual operational profits for various sizes of BESS and electrolyzer under nine different prices are presented in Figure V-13, which represents the annual operational profits using color scales, and Figure V-14, which presents them as 3-D column. It can be seen that for all nine price scenarios, the annual operational profit increases when the technologies sizes increase. However, the rate of changes in the annual operational profit decreases as the size of one of the technology increases.

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The structure of the annual operational profit shares the same trend identified in section 5.2.2.2.

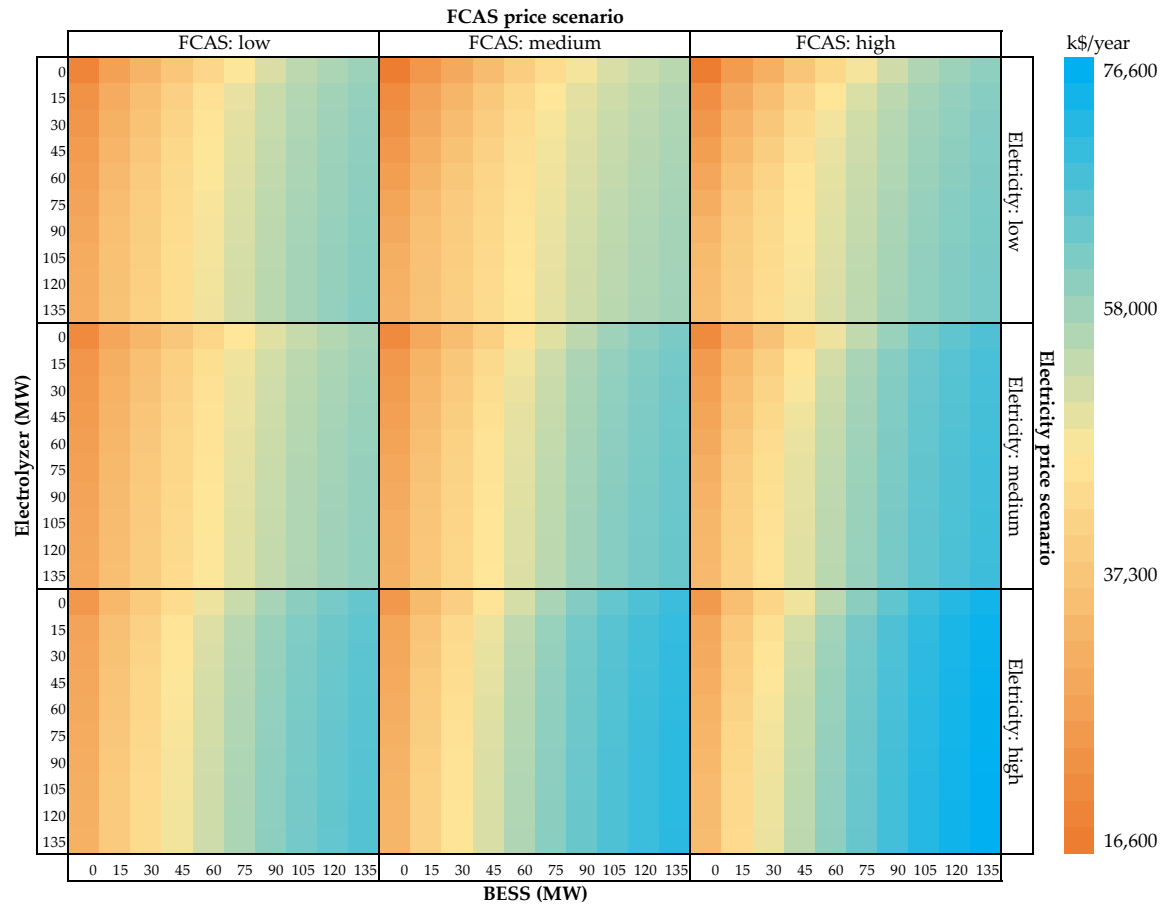


Figure V-13. Color scales representation of annual operational profits

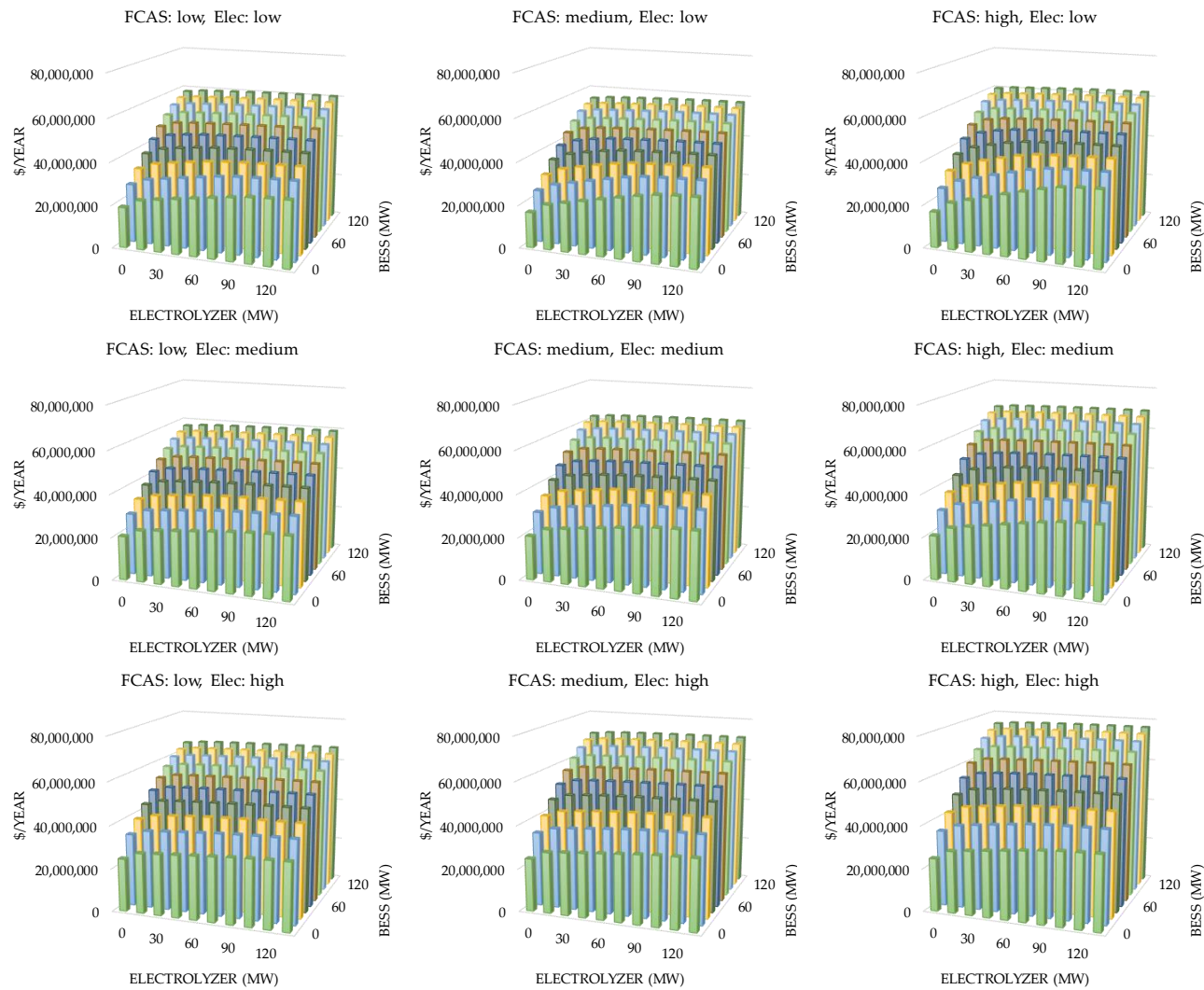


Figure V-14. 3-D column representation of annual profit

5.3.2.3 Optimal investment

The case study is solved considering a 20 years expansion horizon, with a discount rate of 8%. In the initial year, i.e., year 0 (Y0), there is no BESS and EP installed. It is assumed that in each year, only three units can be invested. That is, up to 15 MW of BESS, and/or 15 MW of electrolyzer can be installed each year. The optimal results for each year under nine price scenarios are presented in Figure V-15.

FCAS: low, Elec: low												FCAS: medium, Elec: low												FCAS: high, Elec: low											
	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	...	Y25	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	...	Y25	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	...	Y25		
BESS	0	15	30	45	60	75	90	105	105	105	105	0	15	30	45	60	75	90	105	105	105	105	0	15	30	45	60	75	90	105	105	105	105	105	
EP	0	15	15	15	15	15	15	15	15	15	15	0	15	15	15	15	15	15	15	15	15	15	0	15	15	15	15	15	15	15	15	15	15		

FCAS: low, Elec: medium												FCAS: medium, Elec: medium												FCAS: high, Elec: medium											
	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	...	Y25	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	...	Y25	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	...	Y25		
BES	0	15	30	45	60	75	90	105	105	105	105	0	15	30	45	60	75	90	105	105	105	105	0	15	30	45	60	75	90	105	105	105	105	105	
EP	0	0	0	0	0	0	0	0	0	0	0	0	15	15	15	15	15	15	15	15	15	15	0	15	15	15	15	15	15	15	15	15	15		

FCAS: low, Elec: high												FCAS: medium, Elec: high												FCAS: high, Elec: high											
	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	...	Y25	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	...	Y25	Y0	Y1	Y2	Y3	Y4	Y5	Y6	Y7	Y8	...	Y25		
BES	0	15	30	45	60	75	90	105	105	105	105	0	15	30	45	60	75	90	105	105	105	105	0	15	30	45	60	75	90	105	120	120	120	120	
EP	0	0	0	0	0	0	0	0	0	0	0	0	15	15	15	15	15	15	15	15	15	15	0	15	15	15	15	15	15	15	15	15	15		

Figure V-15. Optimal sizes of BESS and electrolyzer (MW) at each year throughout the planning horizon under different price signals¹⁷

From the results, it can be seen that the electrolyzer is more profitable when the electricity prices are low. That is because more revenues can be gained by importing electricity at low price periods to produce hydrogen which can be then exported. This is particularly observed when comparing low FCAS price scenarios with different electricity price scenarios (see the first column), i.e., the electrolyzer is only installed when the electricity price is low. As the electrolyzer can participate in FCAS markets, it is beneficial to be installed when the FCAS price is medium or high, even with medium or high electricity prices. However, the potential revenue

¹⁷ Y* represents stages. For example, “Y0” represents initial stage, year 0, “Y1” represents year 1, etc.

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of the electrolyzer participating in FCAS markets is low. That is because when the electrolyzer is shut down, it can only participate in lower FCAS markets, which have much lower values than raising FCAS markets most of the time. On the other hand, providing raise FCAS requires operation footroom in the electrolyzer, which increases the electricity import or reduces the electricity export of the VPP. As a result, the optimal capacity of the electrolyzer to be installed is the same across medium and high FCAS price scenarios.

On the contrary, BESS brings more values to the VPP. Firstly, it can store electricity when the wholesale price is low and discharge at a higher price. However, the ability of the BESS shifting electricity import/export period is limited due to the energy content constraints. Moreover, the BESS also has great potential in FCAS markets, as it can use both raise FCAS and lower FCAS in either charge or discharge mode. Thus, the optimal capacity of the BESS is much higher than the electrolyzer across all price scenarios.

Based on the candidate decisions as presented in Figure V-15 and the probability of various price scenarios (see Table V-10), the optimal investment decision is made so as to minimize the maximum regret. The optimal investment decision is illustrated in Table V-11.

Table V-11. Optimal investment decision

Year	0	1	2	3	4	5	6	7	8	...	25
BESS size (MW)	0	15	30	45	60	75	90	105	105	105	105
EP size (MW)	0	15	15	15	15	15	15	15	15	15	15

5.4 Summary

In this chapter, a comprehensive modeling framework for developing business cases for DMES and DER is proposed. More specifically, the presented model assesses various CBA metrics and optimal investment solutions, taking into consideration of all potential revenue streams and costs from multi-market participation and multi-service provision and the capital costs associated with the investment. The DMES operation model presented in Chapter IV is deployed to get the optimal results for multi-market participation, multi-service provision, and devices' operation. The information is passed to assess CBA metrics and to find the optimal investment options. An optimal planning model adopting a roll-out method is proposed for scenario-based investment. A risk-based decision-making model is carried out to consider long-term price uncertainty.

The proposed modeling framework is demonstrated with two case studies, which have distinct set-ups with regards to the technologies, loads, market participation and services provision. The first study demonstrates the feasibility and business case of an urban VPP in the context of VIC, which is proposed based on the resources available at the UoM FB campus. The proposed VPP consists of large loads from buildings, and DER including PV, BESS, and gas generator. The size of the DER within the VPP is relatively small compared to the electricity demand from the buildings. The VPP participates in six contingency FCAS markets, DR markets, and cap contract market, while imports electricity from the retailer with a fixed contract. The sensitivity study on the impact of electricity and FCAS prices are also carried out. The results indicate clear business cases of developing such VPP, under all price scenarios. The second case study is carried out based on the

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background of a RES, electricity, and hydrogen VPP, which is located in a remote area in SA and is weakly connected to the rest of NEM. The proposed VPP participates in the wholesale electricity markets, contingency FCAS markets, and fulfill the FFR obligations of the solar farm within the VPP. The optimal sizes of BESS and electrolyzer for the VPP are analyzed, with a sensitivity study carried out with various wholesale electricity price scenarios and FCAS price scenarios. Both case study has demonstrated the suitability of the proposed modeling frameworks in assessing business cases of various DMES and DER.

Chapter VI. Conclusion and remarks

6.1 Contribution and novelty

This thesis developed a comprehensive, integrated, techno-economic and business case modeling framework, which focuses on exploiting flexibility from demand-side resources so as to aid the energy system transition. The objectives that are identified in this research have been met. Specifically, this thesis has firstly, investigated electricity-related markets, flexibility-related markets, financial markets and grid services that are relevant to DMES, including their commercial agreements and values. Potential services featuring DMES such as distribution network reliability services are also studied. Secondly, a temporal and spatial multi-energy demand model is developed to provide fundamental information on understanding the multi-energy demand and insights of when and where can the flexibility be extracted from. Thirdly, a DMES operation model, which is able to properly quantify the value of the flexibility, is formulated, considering multi-market participation and multi-service provision. And lastly, a business case assessment model is developed to build new business cases for DMES and DER, and an investment model is formulated considering uncertainty from the market price variations to support the business cases. The aforementioned methodologies and models are demonstrated with several case studies, so as to illustrate their functionalities and potential applications.

The first contribution of this thesis is the comprehensive review of the existing and potential markets and services. The contribution can be particularly found in the study on the distribution network reliability service, which is a new service

that can be provided by DER so as to increase the reliability level of the distribution network. This review provides basic information such as commercial agreements and values of various markets and services, to support the economic modeling.

In order to understand the nature of the demand, a multi-energy demand model is firstly built to generate temporal and spatial heat and electricity demand profiles. The novel features of this model that are different from the existing energy demand model include, firstly, this model uses a mix of a bottom-up approach and a top-down validation. The bottom-up approach enables the modeling of building physical characteristics that allow accurate modeling of the demand, while the top-down approach validates the results using widely available energy statistics at an appropriate aggregation level. The second novel feature is that the proposed model generates heat and electricity profiles from both temporal and spatial perspectives, which offers a holistic spatial review of the energy demand. The temporal and spatial energy demand also provides the basis of the energy system planning including both operational analysis and investment of infrastructures. A city-level MES model framework is also developed based on the multi-energy demand model, which is able to assess the techno-economic and environmental performances of future scenarios.

Furthermore, a DMES operation model is then developed using the MILP technique, which aims to find the optimal operation solution for DMES. The proposed DMES operation fulfills the research gaps identified in the literature, which integrates both technical constraints of the technologies and commercial constraints of the market participation and service provision. Specifically, the technical constraints enable the physical modeling of technologies, considering the relevant

technical characteristics. The commercial constraints take into consideration of all potential markets and grid services that can be provided by DMES, including energy, FCAS, DR, hedging contract markets, FFR, and distribution network reliability services. The second novel feature of the DMES operation model is the co-optimization of simultaneous multi-market participation and multi-service provision, considering corresponding price signals from various markets and grid services. Specifically, this model does not only consider the existing markets and services, such as energy, FCAS, and DR but also potential new services such as distributed network reliability services and FFR. On top of that, this model also considers a wide range of technologies, including generators, RES, electrolyzers, BESS, TES, and heating and cooling appliances, which covers most common types of technology that are relevant to DMES. This feature brings the third novelty of this model, which is the modeling of the P2G technologies in providing grid services and participating in multiple markets. Lastly, the proposed model adopted an appropriate time resolution, which is in line with the market operation, allowing maximizing the operational revenue from market participation.

A modeling framework for developing business cases for DMES and DER and investment under uncertainty is then carried out. The main contribution of this framework is it provides a systematic approach and methodology for developing business cases, especially for DMES. Moreover, the proposed model considers all potential revenue streams and costs associated with multi-market participation and multi-service provision, which provides a complete picture of the costs and benefits of the investment. The particular novelty can be found in the optimal planning model, which is specifically subject to DMES, adopting a so-called “roll-out” method to identify the optimal investment strategy for scenario-based planning. A

risk-based decision-making model is carried out to consider the uncertainties from price variations of multiple markets. A real-world application of an urban VPP based on resources within the UoM FB campus is examined using the proposed model. This application provides references and guidelines for developing urban VPP.

6.2 Remarks

The integrated techno-economic and business case modeling framework of DMES and the case studies performed in this thesis provide valuable information to many actors in the energy systems. First of all, the temporal and spatial demand modeling framework offers fundamental knowledge for system operators in city-level MES planning and assessing further low-carbon scenarios. Moreover, the value of multi-market participation and multi-service provision is fully captured using the proposed framework, revealing the true values of flexibility to the prosumers. This may increase their willingness in providing operational flexibility by using their DER or changing altering their demand. Secondly, numerous advantages of aggregations, from both technical and economic perspectives, are demonstrated through real-world applications. The business cases that are shown for DMES may potentially encourage parties to perform the aggregator roles, as a result, the potential flexibility of DER can be further exploited. Furthermore, the feasibility studies of DMES provides the system operators an economical source of operational flexibility, which has great potential in maintaining the reliability and security of low inertia power systems.

6.3 Further work

The presented work can be further extended in a few directions. Firstly, the methodology of the DMES operation model can be extended to a real-time optimization model considering uncertainties from market prices, RES, and user behaviors, such as the work presented in [190]. Furthermore, the modeling of reactive power and distribution network constraints are also of interest to be integrated into the DMES operation model. Thirdly, building on the DMES operation model, a framework for designing new market regimes to further exploit flexibility from consumer participation is considered as another possible future direction. This may include determining the incentives and contract terms of the market, using the proposed co-optimization model. Fourthly, the proposed co-optimization framework can be developed as tools for consumers to manage their resources and actively participating in the markets. Fourthly, the energy independence study can be further extended. For example, the impact of the reliability level of the internal consumers and their values needs to be incorporated into the study.

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