The Effect of Decarbonization Factors on Deeply Decarbonized Electrical Systems: Texas Case Study

by

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Abstract

The expectation of continued CO_2 emissions reduction in the power sector has prompted interest among policymakers, regulators and utilities in expanding electrification of other end-use sectors as a way to meet long-term economy wide decarbonization goals. Expanded use of electrification in these sectors to displace fossil-fuel use, such as for heating or transportation, is appealing not only because it eliminates distributed sources of CO_2 emissions and has associated efficiency benefits, but also because it leverages existing end-use technologies and infrastructure. However, the full CO_2 emissions benefit of electrification is contingent on deep decarbonization of electricity systems. This work is centered on the impact of factors that contribute to the deep decarbonization of power systems, under a high electrification assumption and taking Texas as the case study.

The factors studied are the availability and cost of generation and storage technologies; electrification level; demand flexibility; demand response; and the coupling of the power system with the industry to supply electricity-driven hydrogen supply to supply process heat. By means of a Capacity Expansion Model, GenX, and a design of experiments (DOE) framework, each factor is studied in depth at different CO_2 emission intensity targets, starting with the unconstrained system, and then ranging from 85% up to 100% decarbonization (total CO_2 mass yearly offset with respect to 2018). The impact of each factor is quantified in terms of its effect on average system cost (SCOE); installed power capacity; storage needs; wholesale prices distribution and system operation.

Results show that: (1) under no CO_2 constraints (a "No Policy" scenario), the power system tends to decarbonize itself to a level of 72%, driven by assumed cost projections for 2050 and the high availability of variable renewable energy (VRE) in Texas. (2) Achieving a 98% decarbonization implies reaching a system average cost of \$41/MWh, or an increase in system average cost of 17% from the No Policy case. (3) The various factors evaluated here impact power system outcomes (system costs, system total power capacity, wholesale electricity price distribution, reliability) differently depending on the emission constraint. A combination of factors is generally found to lead to favorable outcomes on multiple dimensions. (4) The most impactful factor is the costs of VRE, followed by hydrogen use in the industry and availability and cost of long duration storage (LDES) technologies. (5) Increasing share of VRE generation increases the number of hours of zero wholesale electricity prices, implying that technologies have to rely on only a few hours to recover investments in energy-only markets. Deployment of dispatchable generation sources such as the Allam cycle, LDES, and activating the coupling with the industry to supply electricity-driven hydrogen, reduces instances of zero wholesale electricity prices. (6) Demand-side management factors (demand flexibility and demand response) prove mainly to contribute to reduce the system footprint, reduce price volatility and to a lesser extent, system costs. (7) Higher electrification of energy demand is found to be beneficial not only to increase the cost-effectiveness of decarbonization via VRE generation owing to overlap between peak demand and VRE resource availability, but also contributes to reduce system SCOE and VRE curtailment levels.

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Chapter 1

Introduction

1.1 Context

Climate Change is one of the biggest challenges humanity is currently facing. Linked to the atmospheric greenhouse gases (GHG) concentration, efforts have been made to reduce GHG emissions since the issue was first raised by the United Nations Scientific Conference in Stockholm, Sweden (1972). In its declaration, The UN warned the governments to be mindful on the activities that have impact on climate and raised awareness on the topic. As stated in its report: "A point has been reached in history when we must shape our actions throughout the world with a more prudent care for their environmental consequences. Through ignorance or indifference we can do massive and irreversible harm to the earthly environment on which our life and well-being depend" [19]. This quote is still valid but the current context is even more pressing as despite the efforts made over decades we still have not managed to stop the increase of the heating imbalance of the Earth (Figure 1-1). This means, the rate at which the earth is heating is accelerating. This result is unequivocal, as satellite data compared with in-situ measurements of Earth's heat uptake show no relevant statistical difference [10].

With a share of over 66%, the main contributor to the Earth's heat imbalance (and therefore global warming) is the atmospheric CO_2 concentration (Figure 1-1). This is the reason why actions are being taken by several countries to reduce their

CO_2 emissions rate and making commitments to achieve carbon-neutrality by 2050. Although 186 countries are parties on the Paris Agreement[1], up to this date, only two countries have achieved carbon neutrality, and 128 have commitments to reach carbon neutrality by or before 2050 [6].

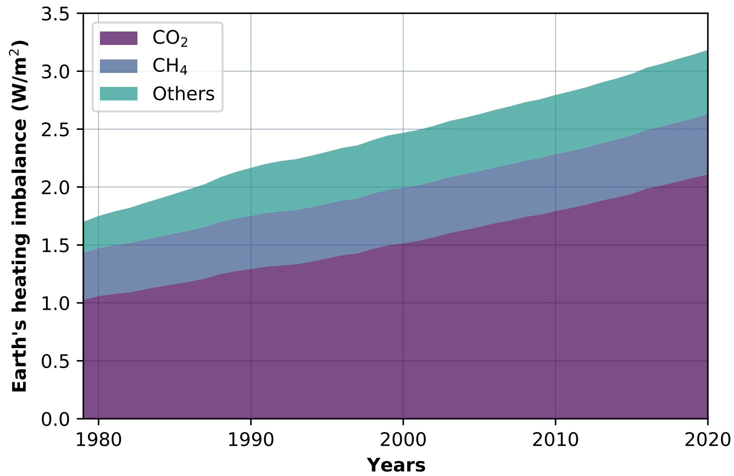

Figure 1-1: Monotonic growth of Earth's heat imbalance, or radiative forcing, relative to 1750. Data from NOAA Annual AGGI [21].

	In Policy Document	In Law	Proposed Legislation	Target Under Discussion	Achieved	Total
Before 2050	3	2	0	0	2	7
By 2050	20	9	4	90	0	123
After 2050	3	0	0	0	0	3

Table 1.1: Number of countries with commitments to achieve carbon neutrality and their status [6]

From 1990 to 2017, global GHG emissions have grown 46% led mainly by China and India. These two countries alone account for 59% and 15% respectively of the increase in global emissions since 1990 [13]. With relatively stable GHG emission levels, the United States accounts for 12% of global emissions. The emissions level of the US show a relatively stable trend with a slight decrease over the 2010-2020 decade (Figure 1-2). On the positive side, two of the emitters, Russia and Brazil, (emitting above 1Gt of CO_2e of GHGs) have reduced their emissions since 1990.

[1]The Paris Agreement of 2015, signed in 2016 by 196 countries and ratified by 191, aims to strengthen the global response to the threat of climate change by setting the goal of limiting the temperature rise by 2050 by less than 2ªC compared to pre-industrial levels [20]

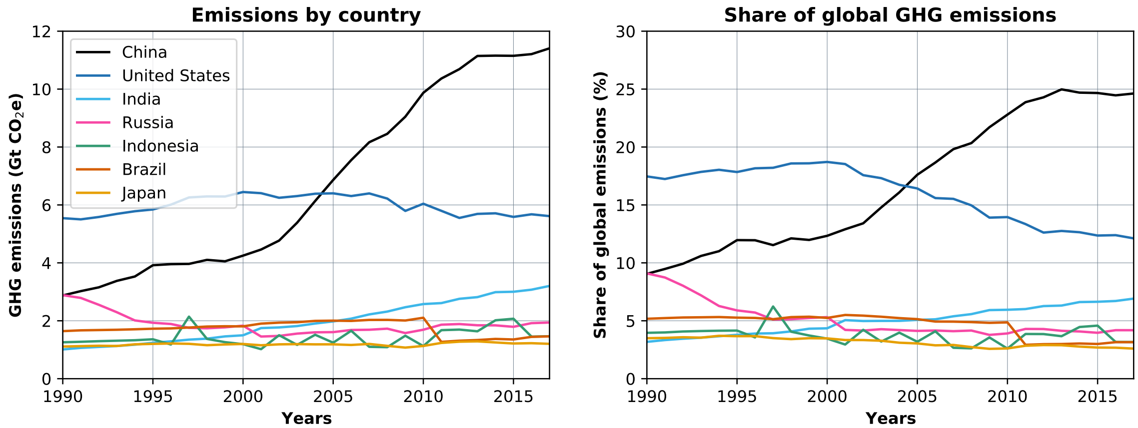

Figure 1-2: GHG emissions by country and share of total emissions by country. Showing the 7 countries that produce more than 1Gt of CO_2e of GHGs. These countries account for more than 57% of total global emissions. [13].

GHG emissions growth is overwhelmingly led by the energy sector. Globally and in 2017, the energy sector accounted for over 75% of the total CO_2 equivalent emissions [13]. As noted in Figure 1-3, the global emissions of the energy sector are becoming relatively stable over the past years, but have increased by 56% from 1990 levels. Nevertheless, the total emissions trend is still upwards and the rate of increase of the heat imbalance growing even faster (figure 1-1). This is a problem that creates a pressing context that requires a rapid decrease in emissions.

As the major source of global emissions, the energy sector is the most relevant to decarbonize and will require a deep transformation towards 2050 to achieve net-zero emissions. The cornerstones of this transformation are: reducing energy consumption by energy efficiency while the economy keeps growing; decarbonization of the electricity sector through large-scale deployment of available variable renewable energy generation technologies such as solar photovoltaics (PV), Wind along with hydro power and nuclear; innovation in energy storage technologies; and electrification of the energy sector as the catalyst of the change [3]. It is clear, therefore, that electrification plays a key role along with the necessary condition of carbonizing electrical systems.

The road ahead to restore Earth's heat balance is complex and not without uncertainties and risks. Policy makers, experts and utilities are raising concerns on reliabil-

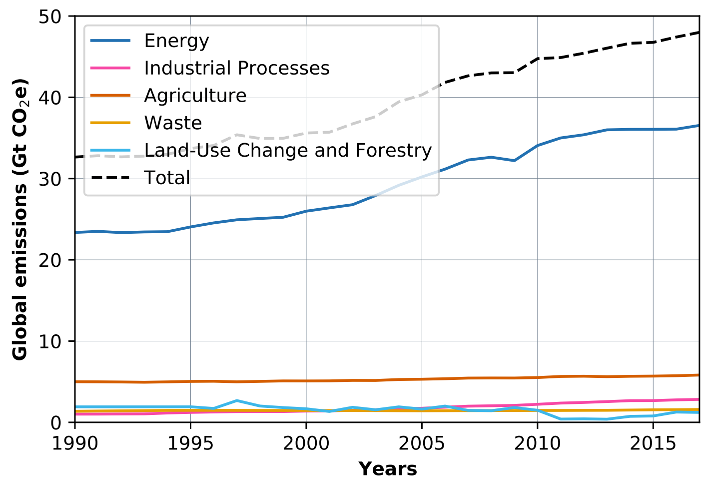

Figure 1-3: Increase in global GHG emissions [13].

ity, costs and operational challenges that may occur in this deeply decarbonized and electrified world. On the demand side, electrical systems load profiles will change, electricity demand levels will increase along with its variability and changes in seasonal peaks will occur both in time and in magnitude [17]. On the supply side, Variable renewable energies (VRE) such as wind and solar have stochastic profiles by nature which could further introduce challenges in real-time balancing without appropriate hardware (e.g. storage, transmission) or software (e.g. better forecasting) mitigation measures.

It is in this context of the transformation of the energy sector to dramatically reduce GHG emissions that this work is framed. Specifically, the analysis will be centered on the factors that influence positively the decarbonization of electricity systems that is essential for economy-wide decarbonization.

1.2 Texas and the United States

In the United States, total primary energy consumption has been relatively stable over the past two decades at a level of about 100 quadrillion BTU (figure 1-4). Although Energy consumption is stable, total CO_2 emissions have decreased over the past two decades, in line with the total GHG emissions (figure 1-2 left, CO_2 represents 91%

of total US GHG emissions). The decrease in the US CO_2 emissions is explained by the 23% emissions drop observed in the electricity sector after 2010 because of the penetration of VRE technologies and natural gas replacing coal generation.

Among the states, Texas is the largest energy consumer with about 14% of total US consumption and the largest CO_2 emitter, with 13% of total emissions. It is interesting to note that among the energy-related CO_2 emissions, both in the US and Texas are led by the electricity and transportation sectors (70% and 63% respectively). This context poses an important opportunity for decarbonization via the adoption of low carbon electricity generation technologies and by electrifying the transportation sector. Moreover and in contrast to the US average, Texas shows that Industry plays a relevant role in terms of share of state energy consumption and state CO_2 emissions (52% and 32%, respectively).

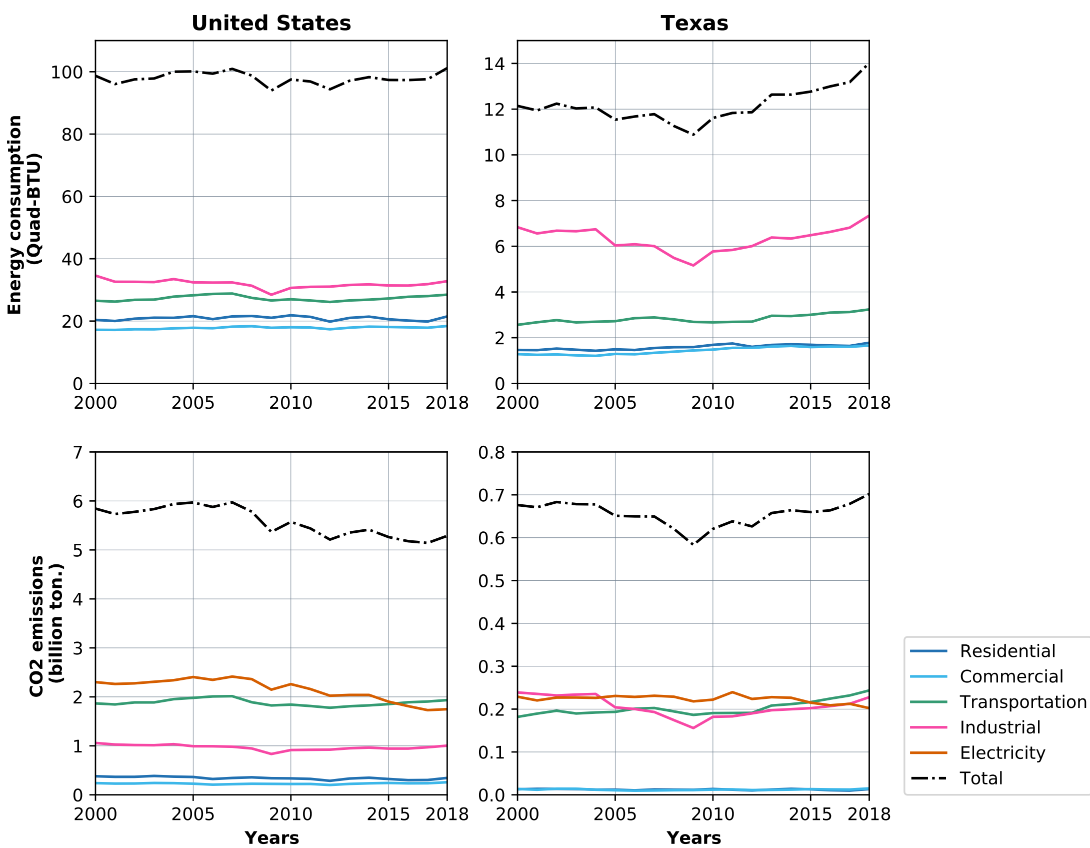

Figure 1-4: Top row: total energy consumption in the United States (left) and Texas (right). Bottom row: total CO_2 emissions in the US (left) and Texas (right). [13].

In addition to being the largest energy consumer and CO_2 emitting U.S. state, Texas is also abundant variable renewable energy (VRE) resources (wind and solar). In [15], the authors analyzed VRE technical potential for different U.S. states and found that Texas is the state with the largest potential for developing Urban and Rural utility-scale PV both in terms of installed capacity and annual generation, as well as for rooftop PV, Concentrated Solar Power (CSP), and Onshore Wind Power. These two reasons, combined with the fact that Texas electric grid is not interconnected to a relevant extent with other states, makes it an ideal setup to study how a deeply decarbonized electrical network will look like in a highly electrified world.

1.3 Research Objectives

This objective of this work is to analyze the impact of five factors that help decarbonize electrical systems under deep decarbonization and electrification assumptions by using a capacity expansion model. The underlying optimization framework employed evaluates the cost-effective investment in generation and storage assets along with its hourly operation profiles (details of the modeling approach in section 2.1.1). Because of its relevance, the analysis is performed on Texas (Section 1.2) and in line with the objectives of most nations, the time frame for deep decarbonization is 2050.

The factors that are analyzed are:

1. **Availability and cost of generation and storage technologies**: future is uncertain and emergent technologies such as Hydrogen storage may be widely available in 2050. Moreover, cost level of storage and renewable technologies is also uncertain and multiple projections predict different price ranges. Section 2.2.1 describes in depth the technologies and price ranges considered in this study.

2. **Electrification level**: electrification is how much of the end-use energy demand of society is met by electricity. Examples of electrification include the use electrical heat pumps instead of natural gas for heating buildings, electri-

cal vehicles for transport, and use of electrical furnaces instead of fossil fuel for heating in industrial processes. Therefore, if electricity is produced mainly from carbon-free electrical sources, electrification can be used as an opportunity to reduce the overall energy sector emissions. In many cases, electrification also improves energy efficiency and reduces primary energy requirements and accompanying environmental and cost externalities associated with primary energy supply (e.g. land, water etc.). Section 2.2.3 provides a detailed description on the electrification analysis of Texas and how this can impact the overall CO_2 emissions reduction of the state.

3. **Demand Flexibility**: Demand Flexibility has been recognized as one of the drivers to support the energy transition towards clean power systems . Providing the capability of shifting demand over short periods of time (hew hours) allows to decrease the peak load of the system and therefore the need for dispatchable generation capacity. Therefore, demand flexibility is seen as an important player in the transition towards low emission electrical systems. Section 2.2.4 describes how short-term demand flexibility is modeled, the limits and the demand sectors that are providing this service.

4. **Demand Response**: Demand response is the how demand reacts to different electricity price levels, on a hourly basis. At a given price, some segments of demand will be more reactive than others and therefore more willing to forgo electricity consumption during those hours.

5. **Hydrogen supply to the industry**: In deeply-decarbonized electrical systems, the production of hydrogen becomes an opportunity to reduce the CO_2 emissions even further by replacing the use of natural gas for industrial heat applications. In this work, the coupling between the power system and industrial demand for hydrogen is modeled. Section 2.2.6 contains the details of this model, along with the assumptions for two storage types: tank and underground geological storage.

The idea of "impact" is analyzed through the following lenses:

1. **Electricity generation assets**: Investment in generation assets such as solar, wind and gas generating plants will depend on the five factors described. Some factors will impact in the need of higher or lower installed capacities. This metric is tracked in terms of the total GW installed by each technology.

2. **Energy storage assets**: Similarly, energy storage requirements will depend on the decarbonization factors. The required energy storage is measured in GWh by each technology under consideration. Section 2.2.1 describes that installed storage capacity is described also by its charging and discharging capacities (in GW),.

3. **System average cost of electricity (SCOE)**: System average cost of electricity is defined as the total amount of investment and operational costs divided by the total annual electricity demand served. ($/MWh).

4. **Wholesale electricity prices distribution**: Hourly marginal electricity prices result from the optimization model, and the different decarbonization factors influence how prices are distributed over time. Prices units are $/MWh.

5. **Impact on system operation**: As the system is decarbonized under the influence of different factors, the modes of operation of the technologies involved changes and also does the way they capture their revenues. Metrics and methods used to describe system operation are: Variable Renewable Energies (VRE) curtailments (%); capacity factors (%); Revenue distribution analysis; frequency band distribution analysis to describe operational patterns.

Chapter 2

Methodology

The study is focused on evaluating the impact of different technology and policy drivers impacting the long-term evolution of the Texas power system. This requires to take into account considerations such as site-specific VRE resource variability, future load projections, techno-economic characteristics of technologies along with physical and operational constraints. This chapter describes the modelling approach with its assumptions, and puts into context the envisioned electrical system of Texas with respect to its current state. The chapter ends with a summary of the experiments conducted to achieve the desired research objective.

2.1 Systems Modeling

2.1.1 Capacity Expansion Model

The analysis uses an open source Capacity Expansion Model (CEM), GenX [18]. This model minimizes the total costs of a power system from a central-planner perspective. Therefore, the optimization model defines the optimal generation, storage and transmission investments, along with the optimal operational patterns for every asset in the network. the optimization has hourly resolution and bounded by a predetermined load profile, VRE profiles that are site-specific, operational constraints of technologies and other imposed policy constraints.

In particular, for this Texas study, a model with 7 years of VRE resource data (2007-2013) combined with a single year of load data (2012) with hourly resolution was implemented in GenX. This allows the model to evaluate grid operations while including both inter- and intra-annual variations in VRE resource availability. In addition, by preserving chronology, the model achieves a characterization that takes into account the inter-temporal operational constrains of technologies (i.e. ramping constraints and energy balance of storage technologies). The main grid-level assumptions considered for the model are:

1. To favor 7-years of hourly temporal resolution, spatial resolution is reduced to model Texas as a single zone ("Copper plate" assumption). this means that supply and demand are balanced hourly within a single zone and no intra-region transmission constraints or investment is considered.

2. Value of lost load: The option of shedding load is provided at a price of $50,000/MWh for the base case. Additional price-sensitive demand is modeled as part of policy driver in section 2.2.5

3. Linearization of unit commitment (start-up/shut-down), minimum up/downtimes and hourly ramping constraints. Typically, power plants are designed with a minimum power-output operational point and finite constraints of minimum up/downtimes and ramping constraints. In this model setup, generators are modeled as a pool and not as individual units, allowing to linearize the unit commitment decision and ramps and thus avoiding binary variables in the model that describe the commitment of a single generation asset (0 or 1). Prior work has shown that this approximation is reasonable when modeling multiple units for each resource type [28].

4. For storage technologies, storage state of charge and charge/discharge inter-temporal constraints is incorporated. The model carries the information of the state of charge from one period of time to the next one. Degradation of storage technologies is not explicitly modeled, but rather captured in the fixed cost. Ramp rates constraints of storage is also not modeled

5. VRE availability. VRE resource is constrained to the maximum available for every hour over the seven years modeled.

6. Carbon emission constraints. For every optimization exercise, an exogenous carbon emission intensity policy is defined. These constraints define the maximum amount of grams of CO_2 that can be emitted for every kWh of electricity dispatched. In section 2.1.2 it is detailed how this emission intensity policy is translated to kTon of CO_2 in Texas and, most importantly, to a percentage of decarbonization of the electrical system with respect to 2018 emission levels.

7. Greenfield assumption. As will be shown in section 2.1.2, Texas is modeled as greenfield. This means that by the year of the simulation (2050) the model is thought to be in a scenario where the current fleet of generators is already retired and the central planner is able to build an optimal configuration of the electrical system 'from scratch'.

8. Full cost recovery. IN the model setup, all generators break even: investment costs are recovered by the revenue obtained from selling the electricity in the market [2].

9. Perfect foresight. The profiles for hourly VRE resource availability and electricity demand are known for the model therefore it takes into account the 7 years of VRE resource availability for the optimization.

The outputs of each model optimization run include: installed generation capacity; installed storage capacity; hourly operation of each resource and marginal electricity cost profiles; total annualized cost of investments, operations and non-served energy.

A key metric of interest is the System Average Cost of Electricity (SCOE) is defined as the sum of the annualized investment costs of the system modeling, divided by the total electricity demand served. This metric will be used to compare the impact of the different decarbonization factors across scenarios. SCOE is defined as the total annualized investment and operational costs of the system modeling (i.e. the objective function of the GenX model), divided by the total annual electricity demand served

[25]. This is in contrast to the levelized cost of energy (LCOE) or levelized cost of storage (LCOS) metrics, both of which are technology-specific cost metrics that are computed with a static view of the power system, require specifying a fixed dispatch profile for the resource in question, and often lead to misleading inter-technology cost comparisons. Instead, the SCOE metric is computed as an output of the CEM and its variations across different scenarios and provides a view of the system impact of various technology and policy drivers under assumptions of perfect foresight, full cost recovery and optimal investment and operation.

Further details on the modeling formulation can be found in [18] and other published works such as [14]. The following are the key limitations of the model:

1. Impact of weather. Although site-specific multi-year hourly VRE resource profiles are incorporated in the model, the impact of extreme weather events on demand (demand profile is the same for the seven years) and generation assets is not included in the model. This was the case in February 2021 in Texas, where unusual low temperatures impacted in a relevant way the generation capacity in ERCOT, leading to major outages [16].

2. Perfect foresight. In line with other capacity expansion models, perfect foresight is assumed for the optimization to decide the optimal asset mix and operational profiles. In real life, however, perfect information of load and VRE resource availability in future periods is not feasible and short-term adjustments are needed to cope with unanticipated deviation from forecasts.

3. Hourly resolution. The temporal resolution of the model is limited to one hour, and therefore intra-hour VRE resource and load variations are not captured.

2.1.2 Texas Electricity Demand Modeling

As mentioned in section 2.1.1 Texas is modeled as a single zone. Therefore, the hourly electricity demand profile is unique for the entire state. The reason behind selecting this spatial representation is because: a) ISO of Texas (ERCOT) covers about 90%

	Peak (GW)	Mean (GW)	Total (TWh)	CoV (-)
ERCOT 2018	73.3	42.9	376.2	0.23
EFS Reference 2050	110.7	62.1	543.5	0.24
EFS High 2050	151.1	81.6	715.1	0.26
% Increase 2018 - 2050 (High)	106%	90%	90%	12%

Table 2.1: Comparison between electricity load of ERCOT in 2018 [7] and NREL's Electrification Future Study projections for 2050 [1]

of the state's electric sector, b) it does not have significant interconnections with other states and c) it has newly expanded transmission capacity between the north-west where high VRE potential is found, to the south-east where major demand is located [8]. This makes it reasonable to approximate the Texas grid as a single zone, that simultaneously makes it computationally tractable to choose a model temporal resolution that spans multiple years of VRE resource data.

The model of demand considers what the electrical load would be in 2050 based on the results of the analysis made by NREL in the Electrification Futures Study [1], under two levels of electrification: High and Reference. Table 2.1 compares the electricity load profile main characteristics of ERCOT in 2018 and the load profiles in 2050 developed by the EFS study (Reference and High). Since the idea is to deeply decarbonize the energy sector, the High Electrification scenario of the EFS study is considered as the base case for the analysis in this work. As noted in Table 2.1, due to the high electrification assumptions, demand is expected to grow with respect to 2018 by 90% both in the total energy consumed and the mean load. Peak load is expected to be more than double as today and reach 151GW in 2050, because of increased penetration of electric vehicles. The increase in demand is mostly driven by the electrification of the transportation sector (see Figure 2-8).

The increase in volatility, captured by the coefficient of variation (CoV[1]) is clear in Figure 2-1 where one can also note that 2050 projections show a greater difference between the summer and winter peaks in comparison to 2018.

[1]The coefficient of variation, defined as the standard deviation divided by the mean, is a metric of the dispersion of the data and is useful to compare the volatility between two data sets.

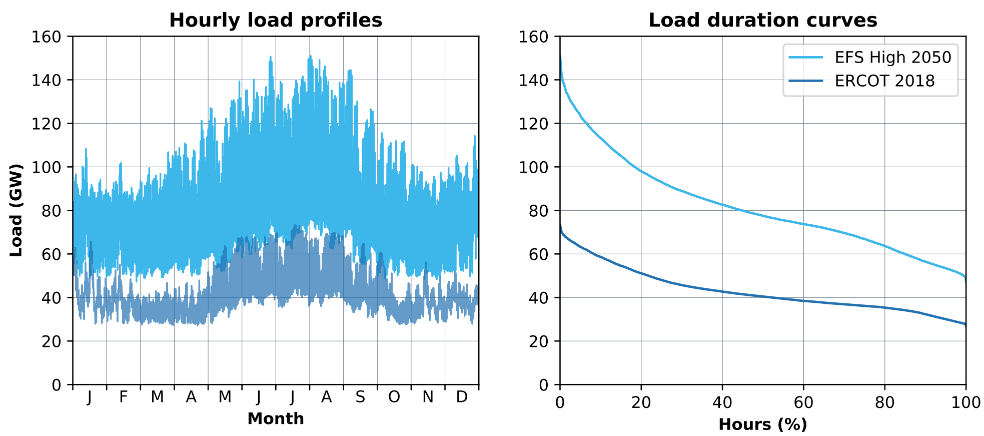

Figure 2-1: Comparison of the load profiles between ERCOT 2018 and EFS data by 2050. Left panel shows the time series over the year and the right side shows the load duration curve, sorting the load from the highest to the lowest values. Load duration curves helps to visualize the spread between hourly data points.

2.1.3 Texas Generation Fleet and Greenfield assumption

As of April 2021, total installed capacity in ERCOT is 141.7 GW [4], equal to 1.93 times the peak load observed in 2020 of 74.33 GW [7]. Table 2.2 shows the installed capacity in ERCOT by technology in 2019, which indicates that the generation fleet is mostly composed of Natural Gas power plants, followed by wind capacity that has come into operations mostly over the past ten years. In Texas, natural gas power plants median age is 20 years and coal power plants is 40 years (figure 2-2). Nuclear plants were built in the late 80's and have an average age of about 30 years.

	Nat. Gas	Coal	Other	Nuclear	Solar	Wind	Storage	Total
Installed Cap. 2018 (GW)	77.5	19.3	1.5	5.1	2.0	24.1	0.1	129.5
Installed Cap. 2018 (%)	59.8	14.9	1.1	4.0	1.5	18.6	0.1	100.0
Installed Cap. 2021 (GW)	79.2	19.3	1.5	5.1	5.7	30.7	0.2	141.7
Installed Cap. 2021 (%)	55.9	13.6	1.1	3.6	4.0	21.6	0.2	100.0

Table 2.2: ERCOT Installed power capacity in 2018 and 2021 (as of April 2021) [4]. 55% of the increase in installed capacity from 2018 is driven by investments in Wind generation.

The favorable wind and solar resource potential along with declining capital costs are shifting the electricity generation mix in Texas towards increasing VRE generation and consequently lower CO_2 emissions.This is evident by the planned retirements

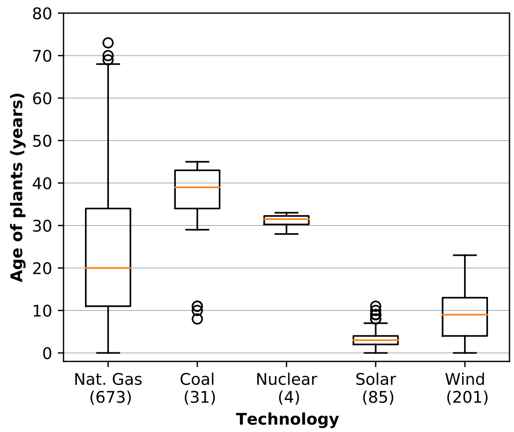

Figure 2-2: Box plot of the age distribution of the power plants in ERCOT as of April 2021, showing the five technologies that account for 99% of the installed capacity. Below the label of each technology and in parenthesis the total number of power plants is shown [4].

and capacity additions in Figure 2-3. Planned retirements are mostly of Coal and Gas power plants and up to 2050 the declared retirements are 10.2 and 9.8 GW, respectively, representing 50% and 12% of the current installed capacity.

On the capacity additions side, total new Wind and Solar capacity is expected to grow by at least 9 and 12 GW by 2024, as new projects are incorporated in the planning each month. Wind and Solar account for 77% of total new planned capacity. Notably, storage additions[2] are expected to be 2.0 GW both in 2021 and 2022 or about ten times the current amount of storage capacity. Of the planned 2.0 GW of storage, as of April 2021 1.25 GW is under construction.

By 2050,the thermal power plants as of 2018 will have a median age of over 50 years, which makes it reasonable to model the 2050 grid under greenfield assumptions. In this case, the central planer will be able to optimize the VRE and storage installed capacity mix along with the required gas generation capacity to achieve the desired carbon emission intensity constraint.

[2]Storage additions are classified as batteries by the EIA database without any description of the specific technology description of each storage project [4]

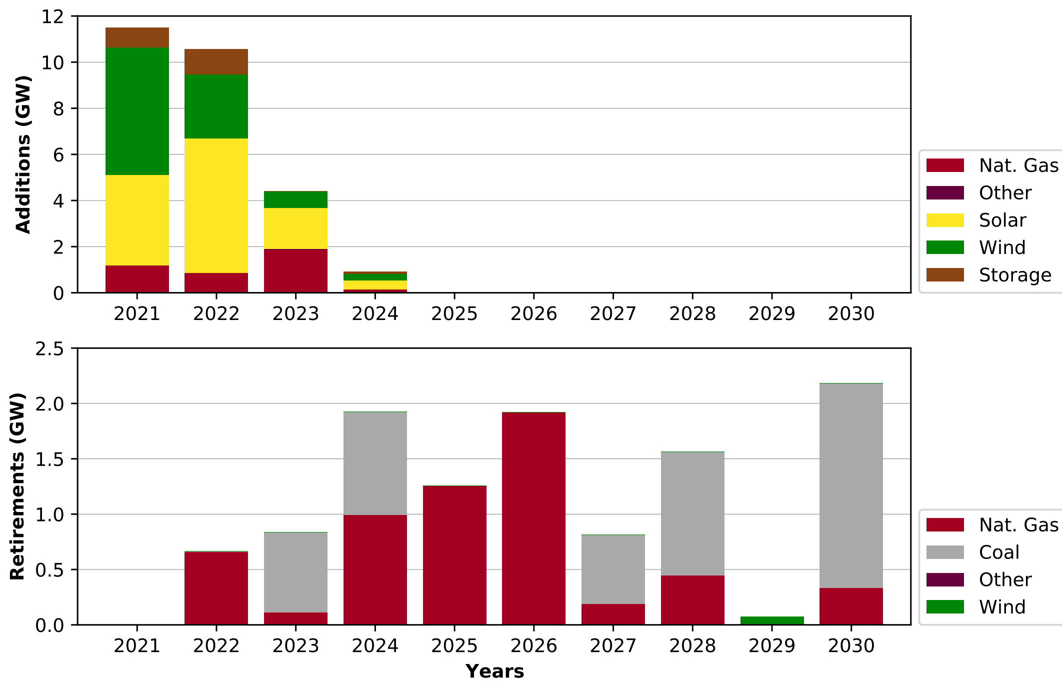

Figure 2-3: Planned additions and retirements of power plants in the years 2021 to 2030, evidencing the transition towards a system of increased VRE penetration[4].

2.1.4 Carbon Emission Intensity Constraints

Carbon emission intensity constraints are imposed in the model by specifying the dispatched generation must not exceed a specific intensity, specified in terms of grams of emitted CO_2 per each kWh of electricity dispatched. By defining the constraint as an intensity metric, it allows to compare different grids setups, sizes and different regions. In this way, decarbonization efforts are made proportional to each location.

The levels of the CO_2 intensity metric considered for this study are: 50, 10, 5, 1 and 0 gCO_2/kWh. In addition, the "No Limits" policy or unconstrained system is also modeled to identify to which extent the systems tend to decarbonize from today's level under the influence of decreasing VRE and storage technology costs.

As pointed out in section 2.1.3, Texas has and continues to witness a rapid growth in VRE generation. This trend, combined with the replacement of coal generation for natural gas, has decreased the total CO_2 emissions of the electrical system over the past decade[3], from 251 in 2010 to 218 million metric tons in 2019 (13% decrease).

[3]The reference year for decarbonization purposes is sometimes used as 2005. For completeness,

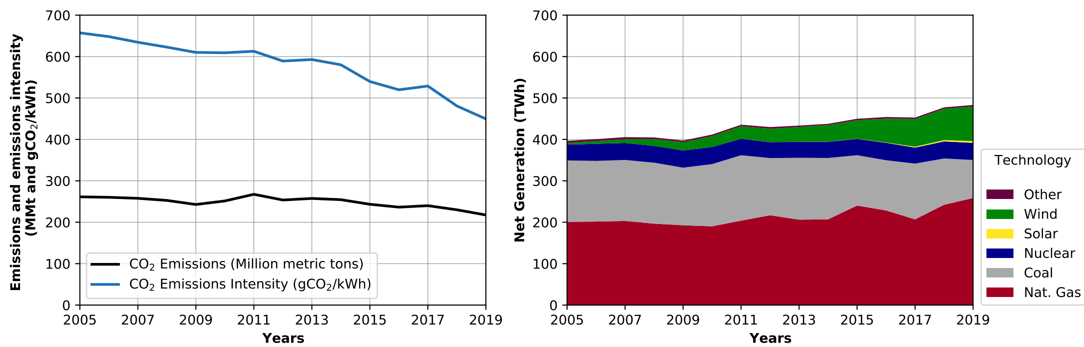

Figure 2-4: Decrease in ERCOT's CO_2 emissions intensity because of rise in generation and decrease in CO_2 emissions [5]. The increase in generation is mainly from wind source and the decrease in emissions is because of the replacement of coal generation for gas.

Moreover, over the same period total net generation has increased 17%, reaching 483 TWh in 2019. Therefore, the decrease in emissions combined with an increase in generation translates in an accelerated decrease in the emission intensity, that reached 450 gCO_2/kWh in 2019 [5]. Table 2.3 and Figure 2-4 illustrates this trend of decreasing emission intensity over the past decade. Although the trend is favorable, Texas has one of the highest emission intensities among the states.

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Net Generation (TWh)	412	435	430	433	438	450	454	453	477	483
CO_2 Emissions (Million metric tons)	251	267	254	257	254	243	236	240	230	218
CO_2 Emissions Intensity (gCO_2/kWh)	609	613	589	593	580	540	520	529	481	450

Table 2.3: Net generation, CO_2 total emissions and emissions intensity in ERCOT over the 2010-2020 decade [5].

To provide an idea of the decarbonization level realized by each modeled emission intensity policy scenario (i.e. constraint from the model perspective), Table 2.4 shows the estimated CO_2 emissions for each policy, in comparison to 2018 emissions level. The cumulative CO_2 emissions for 2050 across the various emissions intensity cases are reported based on the high electrification demand scenario. Naturally, the level of decarbonization for the Reference (or low) electrification load will be higher, since the constraints are the same and the load is lower. However, as will be seen later,

the total 2005 CO_2 emissions were 261 MMt and total Generation was 397 TWh, which corresponds to a CO_2 emissions intensity of 657 gCO_2/kWh

this lower level of electrification translates into lower energy system decarbonization.

	ERCOT 2018	100g	50g	10g	5g	1g	0g
Emissions (Million metric tons)	230.1	71.5	35.8	7.2	3.6	0.7	0.0
Decarbonization (%)	0%	68.9%	84.5%	96.9%	98.4%	99.7%	100.0%

Table 2.4: Level of power system decarbonization reached with each emission intensity policy, taking in to account the load from NREL's EFS High Electrification Scenario. the 100g case has been added to help in the results discussion for the cases without CO_2 constraints.

2.1.5 VRE Resource Modeling

The modeling of solar and wind resource for VRE electricity generation follows the approach proposed by [24] for the development of supply curves that excludes land area such as national parks, mountain ranges, urban areas and Native American territories from plausible development zones. The approach also quantifies the interconnection cost of spur lines to connect the new VRE generators to the existing transmission infrastructure. Texas is divided into 5 zones and for each site, the hourly capacity factor for PV is simulated using a horizontal one-axis-tracking setup over 2007 - 2013 satellite data obtained from the National Solar Radiation Database (NSRDB). Wind hourly CF profiles are simulated using climate reanalysis data from the WIND Toolkit and Gamesa: G126/2500 wind turbine at 100-meter height. After computing the LCOE for each site taking into account the generation and interconnection costs, sites are clustered into bins of similar characteristics. Complete information on the approach can be found in [24].

2.1.6 A note on prices

In February 2021 ERCOT experienced extreme weather events that pushed the limits of grid reliability, leading to blackouts that impacted over 4.5 million homes and businesses. During these events, electricity prices reached levels unseen over the past decade. Price stability is a matter of concern for investors and policymakers for long term capacity planing and the design of compensation mechanisms for generation

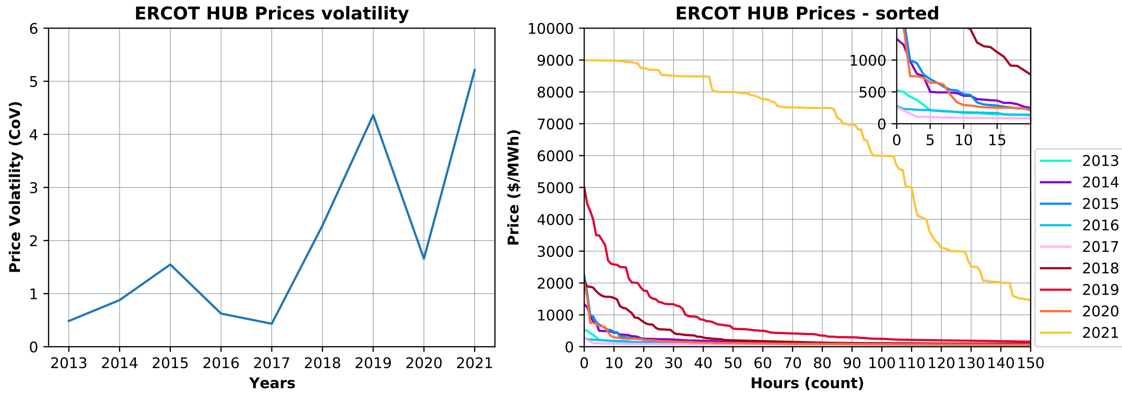

Figure 2-5: Electricity HUB price volatility in ERCOT from 2013 to 2021. Left panel shows the coefficient of variation, evidencing an upwards trend. Right panel shows the sorted prices (price duration curves), where it can be noted that the amount of hours of high prices per year is increasing over time, being 2021 an extreme year with over 150 hours with prices over 1000$/MWh [7].

assets. Besides this dramatic event, prices in ERCOT have shown an increase in volatility over the past decade. In fact, volatility as measured by the coefficient of variation (i.e. standard deviation divided by mean) has increased from 0.48 in 2013 to 5.2 as of July 2021 (figure 2-5, left panel). On the right panel of the figure, the sorted hourly prices are plotted for the years 2013-2021, evidencing an upward trend in time of the extreme prices. 2021 is specially critical because of the blackout events over the winter with over 150n hours of prices above 1000$/MWh.

2.2 Decarbonization Factors

Multiple factors can impact the decarbonization of electrical systems. This section defines the factors and the sensitivities explored in this study.

2.2.1 Availability and Cost of Storage Technologies

Since VRE resource is inherently weather-dependant, a system that heavily relies on them will require a means to balance supply and demand of electricity in a cost-effective way. One of the ways for dealing with resource variability is electricity storage, and multiple technologies are emerging as candidates to be deployed at grid-scale to contribute with the decarbonization efforts.

From the modeling perspective, in the context of this study, storage technologies are classified in two broader groups:

1. Group 1:. Under this group, the Discharge Power Capacity and Energy Storage Capacity can be independently sized, whereas the Charging Power Capacity is equal to the Power Capacity (two independent variables). This group models technologies such as Li-ion, Redox Flow Batteries and Metal-Air. These technologies share the same power electronics for charge and discharge, and therefore these two variables are constrained to be equal.

2. Group 2: For this group of technologies, charge power capacity can be defined independently besides the power and storage capacity (three independent variables). Examples in this group are Hydrogen Storage (sizing of electrolyzer, storage tank and gas turbine is done independently), and Thermal energy storage (Sizing of the heater, storage reservoir and turbine are independent of each other).

Regardless of the group, storage technologies are modeled with distinct parameters that influence their system deployment and operation. Parameters are shown in Table 2.5, along with the cost-sensitivities explored. Main parameters that are used to characterize a storage technology are the investment needed per unit of power for charge and discharge capacity; Investment needed per unit of energy stored; Fixed Operations and Maintenance Costs (FOM) for the charging, discharging and charging systems; and efficiencies for charging (up) and discharging (down). Parameters and costs projections from [12], derived by the technical teams for LDES. Li-ion estimates are obtained from NREL's Annual Technology Baseline (ATB) [22].

The Costs sensitivities can be visualized in Figure 2-6, where from an investment perspective, three broader groups are identified. Highlighted in blue, are the technologies characterized by low storage capacity cost and high power capacity costs, such as Hydrogen, Metal-air and Thermal. With low storage to power cost ratios, this group has been found more efficient to operate in longer term charge-discharge

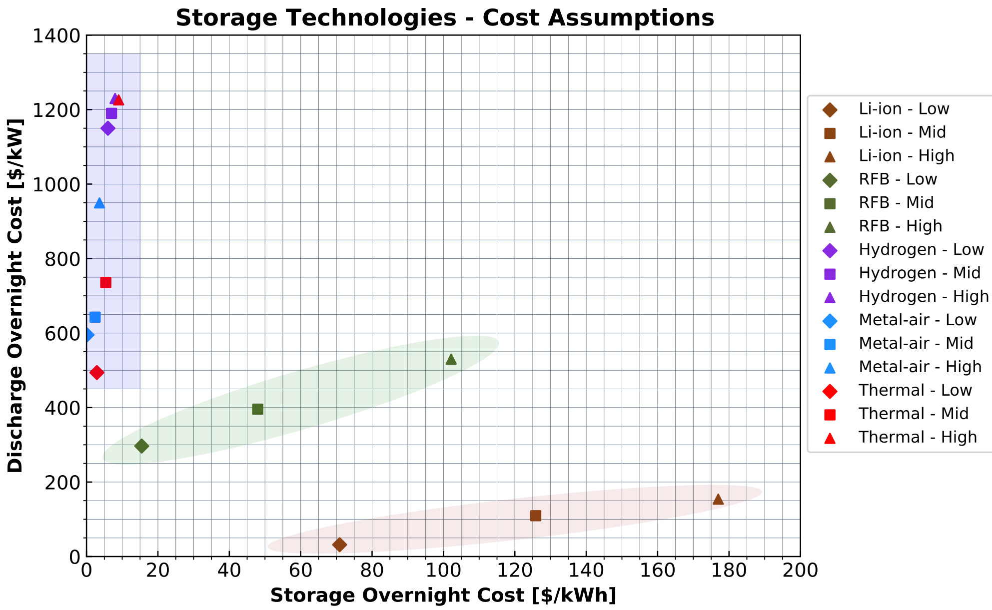

Figure 2-6: Costs projections for the storage technologies modeled. Parameters and costs projections from [12]

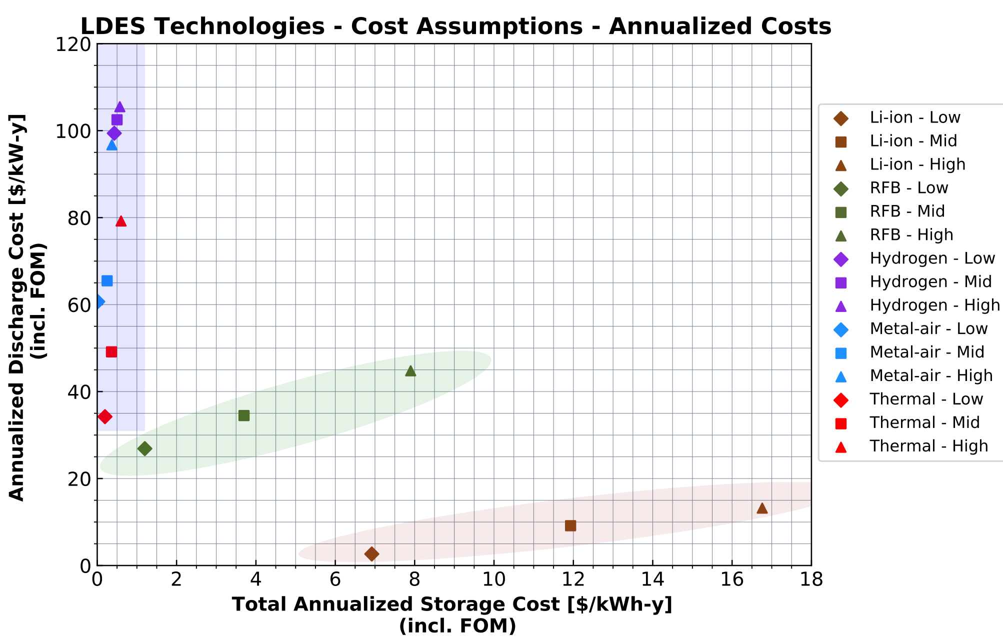

Figure 2-7: Annualized costs of storage technologies. Parameters and costs projections from [12]

Technology	Sensitivity	Overnight Discharging Power Cost ($/MW)	Overnight Charging Power Cost ($/MW)	Overnight Energy Cost ($/MWh)	FOM Discharge ($/MW-year)	FOM Charge ($/MW-year)	FOM Storage ($/MWh-year)	Efficiency Up (%)	Efficiency Down (%)
Li-ion	Today	260,021	-	298,647	1,400	-	6,820	92.0%	92.0%
Li-ion	Low	31,738	-	70,910	250	-	1,420	92.0%	92.0%
Li-ion	Mid	109,564	-	125,840	750	-	2,230	92.0%	92.0%
Li-ion	High	154,088	-	176,978	1,400	-	3,160	92.0%	92.0%
RFB	Today	-	-	171,040	4,080	-	-	91.7%	87.5%
RFB	Low	296,680	-	15,460	4,080	-	-	91.7%	87.5%
RFB	Mid	395,710	-	47,970	4,080	-	-	91.7%	87.5%
Redox-Flow	High	529,920	-	102,160	4,080	-	-	91.7%	87.5%
Metal-air	Today	-	-	3,700	-	-	90	72.0%	60.1%
Metal-air	Low	595,210	-	130	14,880	-	3	70.2%	58.9%
Metal-air	Mid	642,770	-	2,410	16,070	-	60	72.7%	63.0%
Metal-air	High	949,560	-	3,630	23,740	-	90	72.0%	60.1%
Hydrogen	Today	1,363,200	1,770,714	8,000	11,000	75,200	80	58.0%	44.7%
Hydrogen	Ultra-Low	1,189,884	479,286	1,144	11,000	20,355	26	77.0%	65.0%
Hydrogen	Low	1,149,888	356,143	6,000	11,000	15,125	60	80.0%	70.0%
Hydrogen	Mid	1,189,884	479,286	7,000	11,000	20,355	70	77.0%	65.0%
Hydrogen	High	1,229,880	602,429	8,000	11,000	25,584	80	60.0%	60.0%
Thermal	Today	-	-	-	-	-	-	-	-
Thermal	Low	494,000	3,340	2,900	3,930	80	16	99.5%	55.0%
Thermal	Mid	736,000	3,340	5,400	3,930	80	30	99.5%	50.0%
Thermal	High	1,226,000	3,340	9,000	3,930	80	51	99.5%	46.0%

Table 2.5: Parameters that model storage technologies and cost sensitivities explored. Parameters and costs projections from [12] and [22]

cycles [9]. In contrast, Li-ion (brown sector), which has a higher storage to power cost ratio and is found to be propitious for more frequent cycles. In between is the zone highlighted in green, that has an intermediate storage to power cost ratio.

The competitiveness of the storage technologies will be defined by the total annualized costs, including annualized investment costs, annual operation and maintenance and variable costs that depend on the operation profiles. As a proxy for competitiveness, Figure 2-7 shows the total annualized costs taking in to account only investments and fixed O&M costs. It can be noted that in the blue group (low storage to power ratio), thermal storage is the one that becomes more competitive. The full set of assumptions, including capital recovery period, after tax WACC and the annualized cost for storage technologies is included in appendix A, Table A.1.

2.2.2 Availability and Cost of Generation Technologies

A second way of addressing the supply-demand balance challenge, via investments in generation technologies, is by overbuilding VRE and curtailing their output when demand is less than potential generation. Depending on the price of technologies and storage, this path might be more cost-effective than building a significant amount of storage and therefore a sensitivity is studied on the prices projections of utility scale Solar generation and onshore wind (no offshore wind is modeled for this Texas study).

Complete parameters on VRE technologies can be found in A, Table A.2.

Technology	Sensitivity	Overnight Investment Cost ($/MW)	FOM ($/MW-year)
Utility-Scale PV	Low	560,129	6,560
Utility-Scale PV	Mid	724,940	8,490
Utility-Scale PV	High	933,130	10,928
Onshore Wind	Low	722,431	26,645
Onshore Wind	Mid	1,084,798	34,568
Onshore Wind	High	1,259,250	41,590

Table 2.6: Parameters that model storage technologies and cost sensitivities explored. Parameters and costs projections from [12]

Besides VRE generation technologies, natural gas generation also plays an important role in systems that are deeply decarbonized. Gas generation is capable of responding rapidly to short-term balancing of supply and demand, with moderate investment per unit of power, but with the drawback of producing CO_2 emissions and increasing the marginal price of electricity. Thermal generation assets have operational constraints such as ramps, minimum uptimes and downtimes, that are approximated in a linearized manner in the model. Three technologies are considered in the model but no cost sensitivities are explored: Combined Cycles (CCGT), Open cycles (OCGT) and Combined Cycle with carbon capture technology (CCGT_CCS).

In addition to these three gas generation technologies, the effect of a CO_2-based super-critical and high carbon sequestration technology is explored. This technology is known as Allam cycle.

Parameter	OCGT	CCGT	CCGT_CCS	Allam
Overnight Investment Cost ($/MW)	854,380	935,560	2,080,231	1,929,000
FOM ($/MW-year)	11,395	12,863	26,994	53,775
VOM ($/MWh)	4.5	2.2	5.7	2.3
Heat Rate (MMBTU/MWh)	9.51	6.40	7.12	7.07

Table 2.7: Parameters that model gas generation technologies. Parameters and costs projections from [12]

2.2.3 Electrification Level

Electrification is a key driver to achieve the decarbonization of the energy sector. Therefore, it is desirable that electrical load increases towards 2050, in the process replacing the use of fossil fuels for final energy demand, which also increases the overall energy efficiency of the system in most cases. To analyze electrification, energy demand needs to be broken down into four demand sectors: Commercial, Residential, Industrial and Transportation. Each of these sectors can be further broken down into demand subsectors for analysis purposes. The study performed by NREL (Electrification Futures [1]) projected the demand by subsector towards 2050 and concluded that the main driver for electrification is the transportation sector. Figure 2-8 shows that the load growth between the Reference Electrification and the High Electrification is 172 TWh by 2050. Of that amount, 80% is explained by the electrification of the transportation sector, which is little electricity use today. Basically, achieving high electrification will require a change in the composition of the transportation fleet.

The relevance of the electrification of the transportation sector is shown in Figure 2-9. By comparing the Reference with the High electrification scenarios, it is the transportation sector that drives most of the demand and the peak increase.

By analyzing the electrification by subsector (figure 2-10), the greater changes are in the transportation sector, specially in the electricity demand of Light-duty vehicles (passenger cars). Interestingly, Residential demand decreases in the High electrification scenario in comparison to the reference, because of increases in efficiency. In the industry, it is expected to grow the electricity demand used by machines but also by process heat.

2.2.4 Demand Flexibility

The problem of matching supply and demand under high electrification and decarbonization can be also tackled (partially) by making demand flexible. This means shifting demand in time in an intelligent way such that demand is satisfied in periods of time when there is surplus of energy. This approach is likely to be used more

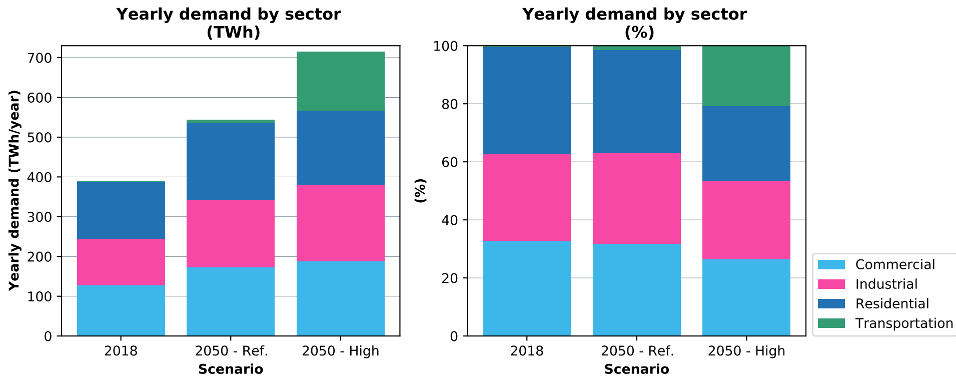

Figure 2-8: Yearly Demand. Breakdown of demand by sector, showing the comparison between the 2018 estimations and the Reference (low) and High electrification Scenarios. Left panel shows total demand in TWh and right panel demand by sector as % of load. Data from [1]

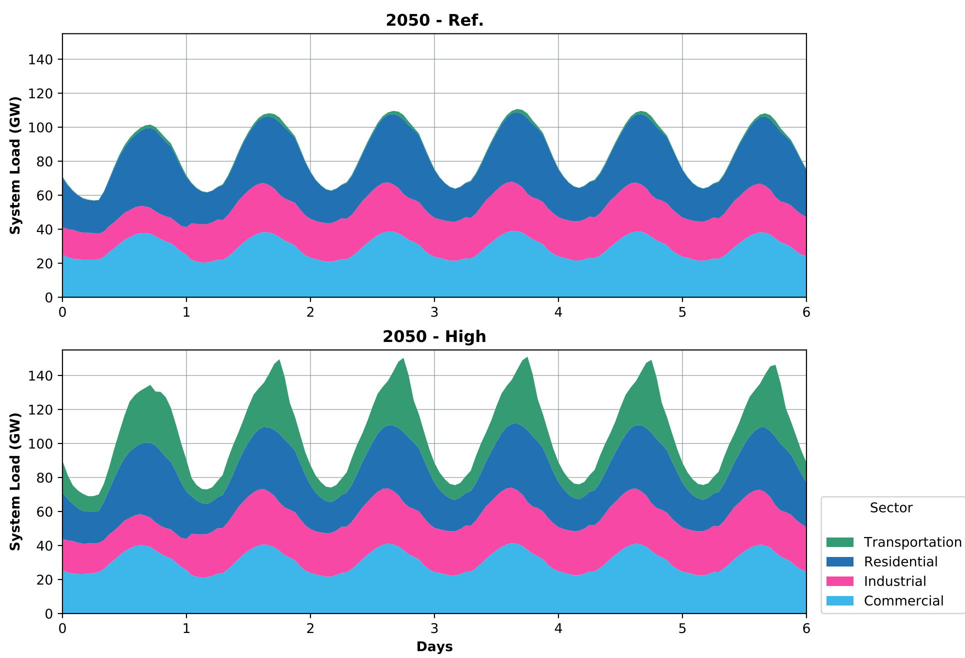

Figure 2-9: Sample from the demand time series, broken down by sectors. Showing 6 days of operation and comparing the reference with the high electrification scenarios. Data from [1]

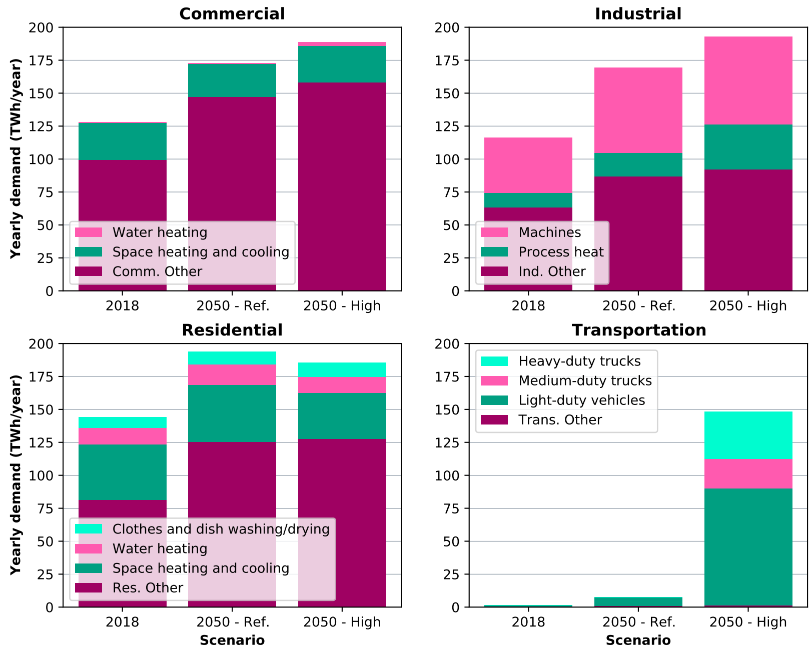

Figure 2-10: Yearly Demand. Breakdown of demand by sector and by subsector showing the comparison between the 2018 estimations and the Reference (low) and High electrification Scenarios. Data from [1]

and more, as smart meters are deployed and subsectors such as transportation are electrified and policies are set in place to foster this grid service. Texas is an ideal case to explore this sensitivity, as is a state with widespread use of smart meters [23].

In this model, intra-day demand flexibility was implemented optimistically. The model allows to shift some fraction of demand for select subsectors within feasible time windows of few hours, at zero cost and without energy losses. These subsectors and each flexibility potential is shown in Table 2.8. The limits and the extent of flexibility are based on the assumptions introduced in the Electrification Futures Study by NREL [1], where hours of delay and advance are proposed, along with the share that can be shifted.

Since the load of each subsector changes over time, the demand flexibility potential for each hour is also variable. For this reason, Table 10 shows the 'Demand Flexibility peak' column, to provide an idea on the maximum load that could be shifted for each subsector at a given point in time. It is important to notice that those subsector peaks do not occur at the same time; the actual maximum potential for demand flexibility

Demand Subsector	Hours Delay	Hours Advance	Share of End-Use That Is Flexible	Maximum Hourly Demand Flexibility [GW]
Commercial HVAC	1	1	25 %	8.6
Residential HVAC	1	1	35 %	7
Commercial Water Heating	2	2	25 %	0.2
Residential Water Heating	2	2	25 %	1
Light duty vehicles	5	0	90 %	33
Medium duty trucks	5	0	90%	3
Heavy-duty trucks	3	0	90%	5

Table 2.8: Demand flexibility potential by demand subsector, showing the temporal constraint, the share that is estimated as flexible and the flexibility peak by subsector.

over the year is 47GW; the average potential is 18GW; and the minimum 4GW. In terms of share of demand, max flexibility potential is 35% of the hourly demand.

2.2.5 Demand Response

Whereas demand flexibility is about advancing or delaying load over time to contribute to the supply-demand balance, demand response involves decreasing demand by defining a price-responsive demand curve. By means of this demand curve, demand segments are created that will decide not to consume electricity if market bulk prices are above a certain level. In the model setup, demand segments are modeled following the framework in [9], where 6 demand segments are defined according to the curve shown in 2-11. The first segment to respond to price (and shed load) is 5% of the load at 2,500$/MWh, the next 5% at 5,000$/MWh until the last 75% of demand is shed at the Value of Lost Load (VoLL) at 50,000$/MWh.

2.2.6 Hydrogen Demand in the Industry for Heat Process

So far, we have explored the different factors that support the decarbonization of the energy sector by transitioning towards a more electrified and decarbonized scenarios. However, decarbonization can go a step beyond just electrification by coupling the electrical system with the industry by producing and selling hydrogen to be used as a heat source for industrial processes (replacing natural gas). Exploring this coupling in

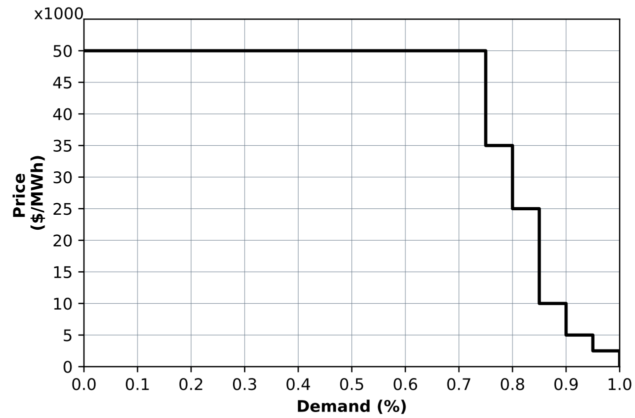

Figure 2-11: Demand response to electricity price levels.

Texas is relevant because Texas industry is the largest industrial energy consumption sector in the US, and the share of Texas' CO_2 emissions accounted by the industry in Texas (32%) is well above the 19% US average (figure 1-4). Therefore, the impact is the greatest and decarbonization of the energy sector in Texas without including the industry could only reach a potential of 68% if the residential, commercial and transportation sectors are fully electrified and electricity is produced only from sources with zero emissions.

The technological setup to provide hydrogen to the industry is shown in Figure 2-12. The model optimizes for the minimum system costs, accounting for the Hydrogen demand in the industry. At each hour, It is decided whether to import hydrogen from an external non-electric supply source at a given price (sensitivities of non-electric H_2 price imports are explored) or to supply it from the electrolyzer[4] or the storage tank, depending on the marginal price of electricity and the supply-demand balance needs of the electrical system. Therefore, the model decides each hour how much hydrogen the electrolyzer produces and whether to supply it to the industry or to store it in the tank.

This sensitivity explores the impact that several levels of hydrogen demand have on the electrical system. This is a special case of demand flexibility, because electricity-

[4]Electrolysis technologies considered here generally split water at or near ambient conditions, and are capable of flexible operation over nearly the entire range of power loads. Further description of electrolyzer technologies can be found in the IEA Future of Hydrogen Report [11]

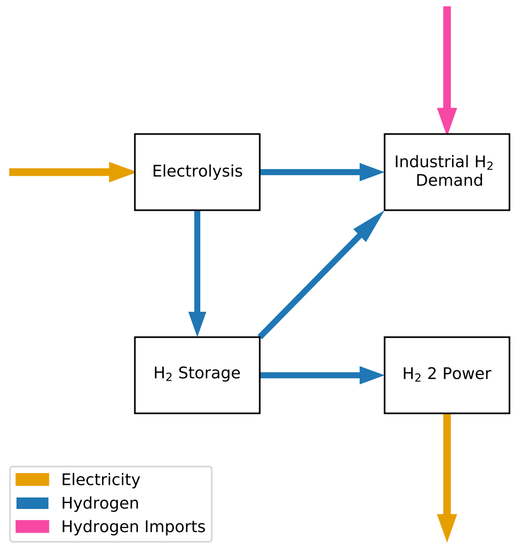

Figure 2-12: Model of industrial demand for hydrogen for process heating.

based H_2 production with electrolysis can be flexibly scheduled thanks to storage capability, even though industrial H_2 demand is modeled to be constant and inflexible across all hours of the year.

The H_2 demand scenarios investigated consider different levels of hydrogen substitution for natural gas as a heat source, ranging from 0, 25, 50, 75, 100 where 100% corresponds to 19.7 GWt (thermal) and the 0% case corresponds to the case without any industrial H_2 demand.Each of these hydrogen demand levels was simulated for various annual CO2 emissions intensity constraints: No Limits, 1, 5, 10, 50 gCO2/kWh. For comparison purposes, a constant 19.7GWt thermal load is equivalent to an average power demand of 25.6 GWe for mid-range charging (electrolyzer) efficiency assumptions as per Table 2.5 (or 17% of 2050 peak demand in Texas according the EFS projections [1]). To estimate the H2 demand level, the DOE 2018 Industrial Data Book data [26] is used, as it enables to identify the large industrial energy users that consume natural gas for heating purposes.

Hydrogen demand is modeled as exogenous and uniform throughout the year. Hydrogen demand was estimated using NREL's 2018 Industrial Data Book. This publication contains a data set detailing the annual energy consumed by large energy-

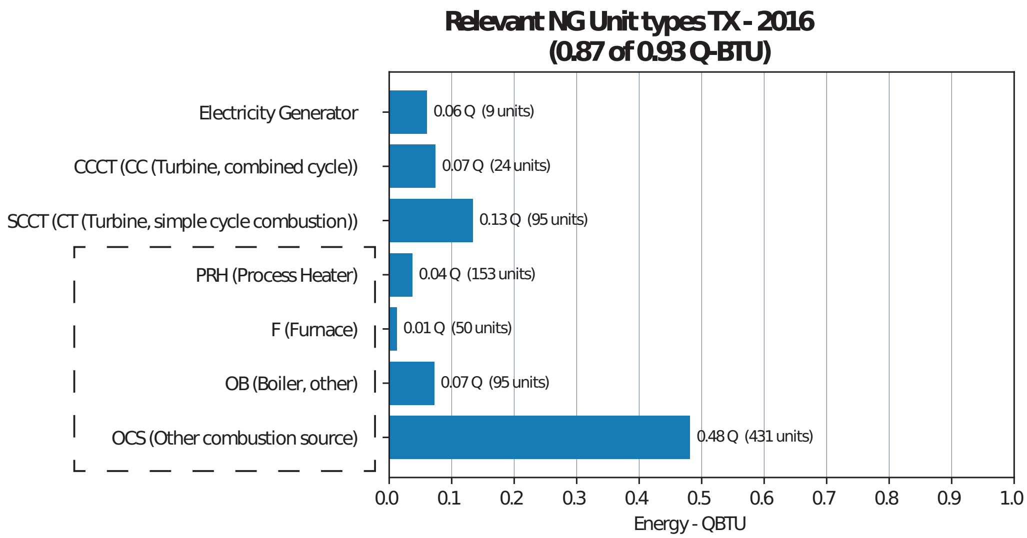

Figure 2-13: Large natural gas consumers in Texas. Showing the amount of energy consumed by unit type. Data from DOE 2018 Industrial Data Book [26]. The black box with dashed lines highlights the units that were considered with potential to be converted from natural gas to hydrogen.

using facilities in 2016. Here, we focus on hydrogen demand from substituting use of natural gas for heating purposes.

Total natural gas consumption by Large Energy Users in Texas accounted for 0.93 QBTU in 2016, which represents about 44% of the 2.1 QBTU of natural gas consumed by the industry in Texas, as reported by the EIA (figure 2-13). From that 0.93 QBTU, we considered for the analysis Process Heaters, Furnaces, Boilers and Other Combustion Sources (box with dashed lines in Figure 2-13) as potential units that use natural gas for heating purposes. Moreover, units whose unit name suggests natural gas is being used as feed stock are excluded. This results in 0.59QBTU of natural gas used for heating. By assuming flat demand, the total of 0.59QBTU/year of natural gas heat is equivalent to 19.7GWt of Hydrogen.

2.3 DOE Summary

The factors that impact grid decarbonization are explored in this work at different sensitivity levels, which are summarized in Figure 2-14. On the storage and generation technologies, availability and price sensitivities is explored. Two levels of electrification are considered: high and reference (as per EFS data), two levels of demand flexibility(enabled/disabled), and two levels of demand response (enabled/disabled). The case of hydrogen in the industry is explored in two ways: first, the level of demand, and second, the level of price for hydrogen imports.

These high number of factors and levels mean a high combinatorial space that climbs up to 2,064,384 scenarios that are run for each emission intensity policy (No Limits, 50, 10, 5, 1 and 0 gCO_2/kWh), giving a total of 12,386,304 set of runs. Since on average the solving time is 10 hours per run, analyzing the full factorial space it's computationally intractable. Therefore, a limited set of experiments is designed to explore the sensitivities and to identify which factors are more impactful than others. Table 2.9 lists the experiments performed, showing for each experiment ID: the experiment group, load level (Load, High/Reference electrification); demand flexibility (DF, y/n); demand Response (DR, y/n); value of lost load (VoLL, 50,000 / 100,000 / 200,000 \$/MWh); and the technology mix comprised by the technologies that are included in the scenario at the given price level projection (low, medium or high). As a special case, hydrogen in experiments 56 through 60 is simulated with geological storage. It is worth noticing that a given technology mix can be shared among different experiments (see experiment 1 and 27). Both share technology mix TM0, but differ in the electrification level.

A brief description of the experiments groups is presented below:

Grp. A: **Storage availability**. Contains the Base Case of the study, defined as a system that has only Li-ion as the storage technology, because this technology has already been demonstrated at grid-scale and is commercially available. Experiment A explores the effect of adding storage technologies under different cost assumptions on the system. Wind and Solar Technology costs are kept at a medium sensitivity level and no Demand Flexibility, Demand Response or Gas Demand (Hydrogen in the industry) is implemented.

Grp. B: **VRE cost**. Here the sensitivity of VRE generation technologies is explored, combined with availability of different storage technologies.

Grp. C: **Electrification**. Experiment Group C is a mirror of experiments 1-4, being the only difference in the electrification level.

Grp. D: **Demand Flexibility**. Experiment Group D is a mirror of experiments 1-4, being the only difference that experiments in group D have demand flexibility enabled.

Grp. E: **Allam Cycle**. In this experiment set, the effect of Allam cycle availability is explored under different mixes of storage technologies.

Grp. F: **Value of Lost Load**. Although not a decarbonization factor, the impact of the Value of Lost Load (VoLL) is explored to understand the extent this impacts costs, reliability and operations.

Grp. G: **Industrial H_2 demand**. Here, the effect of increasing levels of Hydrogen demand as substitute for natural gas in the industry is analyzed. The analysis is performed for two technology mixes (36 and 37) with the difference being that TM37 assumes that hydrogen is stored in underground geological caverns.

Grp. H: **Demand Response**. Finally, the effect of demand response is analyzed. with the technology mixes of experiment group A.

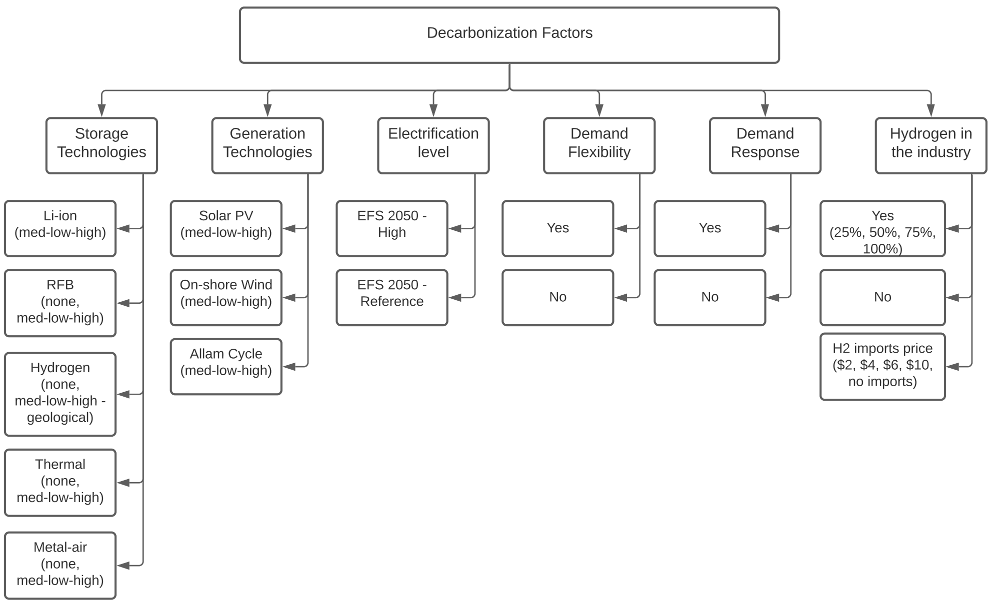

Figure 2-14: Summary of decarbonization factors and the sensitivities explored

ID	Exp. Group	Load	DF	DR	GD	VoLL	Tech Mix	VRE	Li-ion	RFB	Hydrogen	Metal-air	Thermal	Allam
1	A	H	n	n	n	50	TM0	M	M	-	-	-	-	-
2	A	H	n	n	n	50	TM1	M	M	M	-	-	-	-
3	A	H	n	n	n	50	TM2	M	M	M	M	-	-	-
4	A	H	n	n	n	50	TM3	M	M	M	-	M	-	-
5	A	H	n	n	n	50	TM4	M	M	M	-	-	M	-
6	A	H	n	n	n	50	TM5	M	L	L	-	-	-	-
7	A	H	n	n	n	50	TM6	M	H	H	-	-	-	-
8	A	H	n	n	n	50	TM7	M	M	L	-	-	-	-
9	A	H	n	n	n	50	TM8	M	M	H	-	-	-	-
10	A	H	n	n	n	50	TM9	M	M	M	L	-	-	-
11	A	H	n	n	n	50	TM10	M	M	M	H	-	-	-
12	A	H	n	n	n	50	TM11	M	L	L	H	-	-	-
13	A	H	n	n	n	50	TM12	M	M	M	-	L	-	-
14	A	H	n	n	n	50	TM13	M	M	M	-	H	-	-
15	A	H	n	n	n	50	TM14	M	L	L	-	H	-	-
16	B	H	n	n	n	50	TM15	L	M	-	-	-	-	-
17	B	H	n	n	n	50	TM16	L	M	M	-	-	-	-
18	B	H	n	n	n	50	TM17	L	M	M	M	-	-	-
19	B	H	n	n	n	50	TM18	L	M	M	-	M	-	-
20	B	H	n	n	n	50	TM19	L	L	M	-	-	-	-
21	B	H	n	n	n	50	TM20	L	L	M	M	-	-	-
22	B	H	n	n	n	50	TM21	L	L	M	-	M	-	-
23	B	H	n	n	n	50	TM22	H	M	-	-	-	-	-
24	B	H	n	n	n	50	TM23	H	M	M	-	-	-	-
25	B	H	n	n	n	50	TM24	H	M	M	M	-	-	-
26	B	H	n	n	n	50	TM25	H	M	M	-	M	-	-
27	C	R	n	n	n	50	TM0	M	M	-	-	-	-	-
28	C	R	n	n	n	50	TM1	M	M	M	-	-	-	-
29	C	R	n	n	n	50	TM2	M	M	M	M	-	-	-
30	C	R	n	n	n	50	TM3	M	M	M	-	M	-	-
31	D	H	y	n	n	50	TM0	M	M	-	-	-	-	-
32	D	H	y	n	n	50	TM1	M	M	M	-	-	-	-
33	D	H	y	n	n	50	TM2	M	M	M	M	-	-	-
34	D	H	y	n	n	50	TM3	M	M	M	-	M	-	-
35	E	H	n	n	n	50	TM26	M	M	-	-	-	-	M
36	E	H	n	n	n	50	TM27	M	M	M	L	-	-	M
37	E	H	n	n	n	50	TM28	M	M	M	M	-	-	M
38	E	H	n	n	n	50	TM29	M	M	M	H	-	-	M
39	E	H	n	n	n	50	TM30	M	M	M	-	L	-	M
40	E	H	n	n	n	50	TM31	M	M	M	-	M	-	M
41	E	H	n	n	n	50	TM32	M	M	M	-	H	-	M
42	E	H	n	n	n	50	TM33	M	M	M	-	-	L	M
43	E	H	n	n	n	50	TM34	M	M	M	-	-	M	M
44	E	H	n	n	n	50	TM35	M	M	M	-	-	H	M
45	F	H	n	n	n	100	TM0	M	M	-	-	-	-	-
46	F	H	n	n	n	200	TM0	M	M	-	-	-	-	-
47	F	H	n	n	n	200	TM1	M	M	M	-	-	-	-
48	F	H	n	n	n	200	TM1	M	M	M	-	-	-	-
49	F	H	n	n	n	100	TM3	M	M	M	-	M	-	-
50	F	H	n	n	n	200	TM3	M	M	M	-	M	-	-
51	G	H	n	n	n	50	TM36	M	M	-	M	-	-	-
52	G	H	n	n	25	50	TM36	M	M	-	M	-	-	-
53	G	H	n	n	50	50	TM36	M	M	-	M	-	-	-
54	G	H	n	n	75	51	TM36	M	M	-	M	-	-	-
55	G	H	n	n	100	52	TM36	M	M	-	M	-	-	-
56	G	H	n	n	n	53	TM37	M	M	-	Geo	-	-	-
57	G	H	n	n	25	54	TM37	M	M	-	Geo	-	-	-
58	G	H	n	n	50	54	TM37	M	M	-	Geo	-	-	-
59	G	H	n	n	75	54	TM37	M	M	-	Geo	-	-	-
60	G	H	n	n	100	54	TM37	M	M	-	Geo	-	-	-
61	H	H	n	y	n	50	TM0	M	M	-	-	-	-	-
62	H	H	n	y	n	50	TM1	M	M	M	-	-	-	-
63	H	H	n	y	n	50	TM4	M	M	M	-	-	M	-

Table 2.9: DOE Summary. DF : Demand Flexibility DR: Demand Response; GD : Gas Demand (H_2 demand level); VoLL : Value of Lost Load; TM : Technology Mix

Chapter 3

Results

This chapter presents and analyses the results of the experimental setup defined in section 2.3, considering the following impact metrics: Installed power capacity (GW of each technology and this magnitude relative to the system peak load); installed storage capacity (in terms of GWh of deliverable energy capacity and its equivalent of hours of system mean load [1]); system average cost of electricity (SCOE in $/MWh); wholesale electricity prices distribution; and operational analysis of storage dispatch.

The chapter starts by describing the base case and discussing the outcomes in context of the Texas (ERCOT) grid in 2018. The base case analysis is followed by sections that focus on each of the experiment groups described in section 2.3.

3.1 Base Case

The base case (Experiment 1 in Table 2.9) is defined as a system that has only Li-ion as the storage technology at medium cost level[22], along with possibility to wind, solar resources and CCGT, OCGT and CCGT with CCS. Electricity demand is characterized as per the High Electrification demand scenario from the NREL Electrification Futures study[1], and we do not allow for demand flexibility or demand response capabilities. Value of lost load is fixed at 50,000 $/MWh. Figure 3-1 shows

[1] Hours of mean system load is computed by taking the ratio of total storage deliverable energy capacity (i.e. product of storage energy capacity times discharge efficiency) and mean annual system power demand. It is a measure of how long storage serve the mean system power demand.

the system summary results of the base case, showing how installed power and storage capacity, SCOE and curtailments increase as the carbon emission constraint tightens.

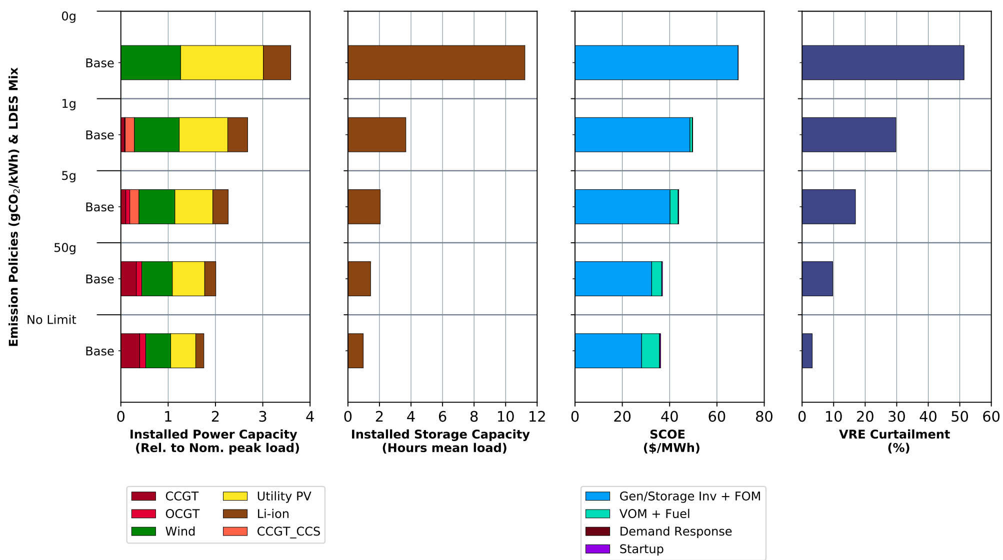

Figure 3-1: Base case system outcomes for various levels of CO_2 emissions intensity constraints. Results shown include installed power capacity, storage energy capacity, SCOE and variable renewable energy (VRE) curtailment.

Emission Constraint (gCO2/kWh)	CCGT	OCGT	CCGT_CCS	Wind	Utility PV	Li-ion	Total
NL	60	19	0	80	80	26	265
50	49	17	0	98	103	36	303
5	16	13	29	115	121	49	343
1	12	2	30	143	155	64	405
0	0	0	0	191	264	87	543

Table 3.1: Base Case Installed Power Capacity, in GW

Figure 3.1 highlights that system outcomes under the 'No Limits' policy case has significant VRE capacity deployment, whose generation leads to an overall grid average CO_2 emissions intensity of 91.6 gCO_2/kWh. This suggests that the system could potentially achieve substantial decarbonization (72% of decarbonization based on annual CO_2 emissions with respect to 2018) even in the absence of any policy drivers. This finding can be attributed to the relatively high quality of VRE sources coupled with 2050 capital costs for wind and solar, which are 29% and 54% lower than 2020 capital costs, respectively[22].

Regarding the installed power capacity, without carbon emission limits, a total of 265GW will be needed by 2050, or 1.75 times the peak load. With 79GW of gas generation by 2050, this is exactly the amount available today in ERCOT (see Table 2.2) and similarly, today the total installed capacity relative to the peak is 1.95 (141GW). The power capacity requirement increases with carbon emissions, reaching a total of 2.2 times the peak load in the 5g case (98.5% decarbonization) or 3.6 times the peak load for the 0g case. This finding can be attributed to the declining marginal value of VRE resources, which is also seen in the increasing VRE curtailment as we approach 0 gCO2/kWh grid emissions intensity.

On the system storage requirements, it is efficient to build Li-ion storage capacity even without carbon emission policies: 26GW of Li-ion, with 79GWh of energy storage capacity or its equivalent of 1 hour of system mean load. This requirement doubles to 2 hours if a 98.4% of decarbonization is targeted (5g case).

Emission Constraint (gCO2/kWh)	Li-ion (hours)	Li-ion (GWh)	SCOE ($/MWh)	Curtailment (%)
NL	1.0	79.2	36.2	3.2
50	1.4	117.5	37.0	9.7
5	2.0	167.3	43.9	16.9
1	3.7	299.9	49.8	29.7
0	11.2	916.1	69.0	51.4

Table 3.2: Base Case Energy Storage Capacity, SCOE and Curtailment.

Regarding system costs, SCOE is dominated by capital and fixed costs under the deep carbonization scenarios (emission intensity at or below 5 gCO2/kWh), as variable (fuel) costs are not dominant. The base case SCOE starts at 36.2$/MWh in the no limits case and almost doubles at 0g, reaching 69$/MWh. Notably, only a 21% increase with respect to the No Limits case is required to reach 98.4% decarbonization with respect to 2018 emission levels (5g case, refer to Table 2.4). SCOE values for the base case are listed in Table 3.2.

Curtailments of renewable energy increase as the carbon emission reaches zero, mainly because VRE overbuilding is used as a mechanism to manage intermittency in VRE generation and balance hourly supply-demand. This can be appreciated in Figure3-2, where VRE overbuilding relative to peak load and storage replace gas generation in during periods of low VRE resource availability. The magnitude of curtailment is the area between the light-blue dashed line and the black dashed line.

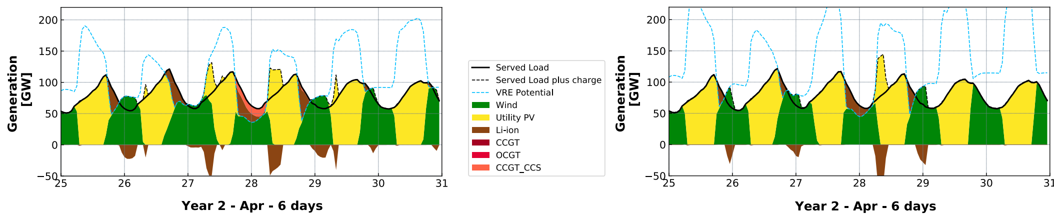

Figure 3-2: Base Case results at 5g (left) and 1g case (right), showing 6 days of system operation. In the 1g case, VRE overbuild along with storage helps to balance the system instead of using gas generation in day 28. The magnitude of curtailment is the area between the light-blue dashed line and the black dashed line.

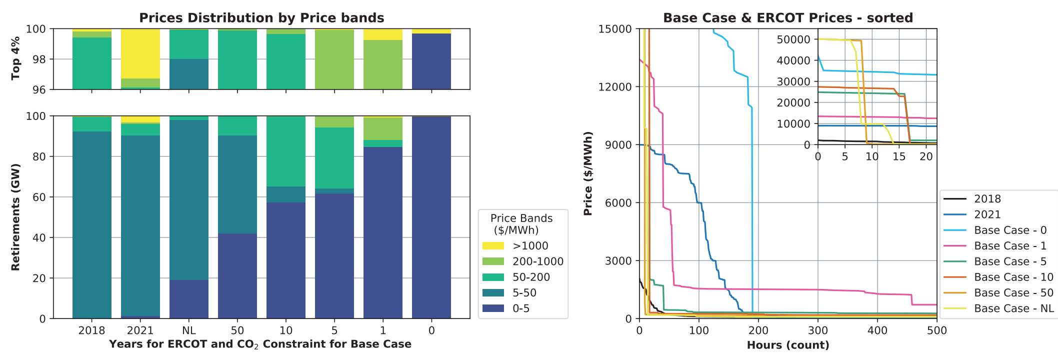

Figure 3-3: Base Case prices distribution under different CO_2 constraints, compared to ERCOT in 2018 and 2021. The left panel shows the prices' distribution by price bands and the right panel, the sorted prices.

Wholesale prices distributions are also impacted with increasing stringency of carbon emission policy. The wholesale price distributions are compared against the sorted prices curves from ERCOT in Figure3-3, where on the left panel, the price distribution is shown sorted by price bin[2]. It becomes clear that as the carbon policy becomes stricter, the \$0-5/MWh price band gains in share, while the natural gas price band (\$5-50) decreases, due to increasing role for VRE generation and declining

[2]Price bins include (1) zero to \$5/MWh, characterized mostly by periods of high VRE generation and curtailments; (2) \$5-50/MWh when natural gas capacity is the marginal generator; (3) \$50-200/MWh when natural gas capacity needs to be started up and the associated start-up costs recovered; (4) >\$200/MWh corresponding to scarcity events, including storage operations (either charging to dispatch in higher priced periods or discharging based on charging in lower priced periods) and load-shedding events.

role for gas generation. At the 0gCO2/kWh case, 99.7% of the time the prices are zero, with just about 200 hours out of the 7 years with extreme prices (right panel of Figure3-3). This behavior is mainly due to the high levels of curtailments that are used to balance the system, when price drops to nearly \$0.

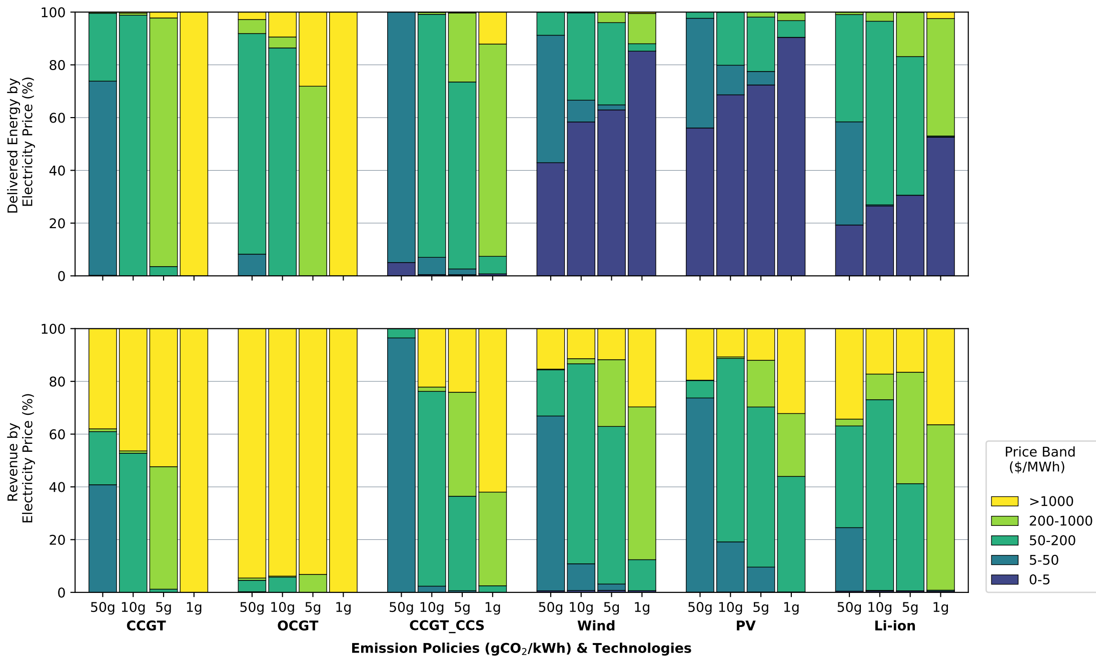

Figure 3-4: Base Case - Technology operation by price band (upper panel) and technology revenue by price band (lower panel), illustrating how technology rely on high prices to break even under deep decarbonization conditions.

It is worth noting that as the carbon emission constraint tightens and the zero price band grows, price volatility (CoV[3]) tend to decrease (From the 'No Limits' policy case to the 1gCO$_2$/kWh, volatility drops from 18 to 7, Table 3.3). The increase in the zero price band or lower prices bands is relevant for how the technologies recover their investments. In line with other capacity expansion models, GenX is designed in such a way that technologies break even [2]. This means that under the efficient system and perfect foresight assumptions embedded in the modeling, as the system decarbonizes, resources dispatch is altered, but all resources recover their investment costs, mostly during scarcity pricing events. This is reflected in Figure 3-4, where

[3]The coefficient of variation, CoV, defined as the standard deviation divided by the mean, is a metric of the dispersion of the data and is useful to compare the volatility between two data sets.

the operation of technologies according to the % delivered energy by price band and the revenue % by price band is shown. Wind, PV and Li-ion deliver energy to the grid predominantly during low price bands ($0-5 band), whereas gas generation technologies operate mostly in the ($50-200 band). Although this is expected because of higher marginal price and startup costs for gas generators, it is also the case that gas resources depend more on extreme prices than VRE technologies for revenues. For example, in the 5g case, half of CCGT's revenue depend on the operation on hours when prices are above $1,000/MWh, which occur only in 15 hours in the 7 years of operation. Conversely, Wind and PV revenue on that price levels account only for 11.7% and 12%, respectively, of the total revenue.

3.2 Impact of Technological Availability

3.2.1 Long Duration Energy Storage - Medium Costs

This section summarizes the system impacts due to availability of long duration energy storage (LDES), with focus on medium costs assumptions (complete set of assumptions for storage technologies is found in Table A.1). The technologies under consideration are Redox Flow, Hydrogen, Metal-air and Thermal, which are combined according to the technology mixes of experiments 2 to 5 (TM1 is Li-ion + RFB; TM2 is Li-ion + RFB + Hydrogen; TM3 is Li-ion + RFB + Metal-air; and TM4 TM2 is Li-ion + RFB + Thermal; all at medium cost assumptions).

Results show that LDES have a positive effect on decreasing SCOE, and curtailments, when compared to the Base Case (Figure3-5). First, for a given carbon emission policy, availability of LDES tends to reduce the SCOE, with SCOE reductions ranging from 2% in the No Limits policy to 32% in the 0g case with respect to the Base Case. At 5g, the reduction in SCOE by adding LDES is up to 8.5% with the Li-ion+RFB+Metal-air mix.

The SCOE reductions with LDES deployment are achieved mainly by displacing investments in Li-ion storage (expensive storage capacity) and dispatchable natural

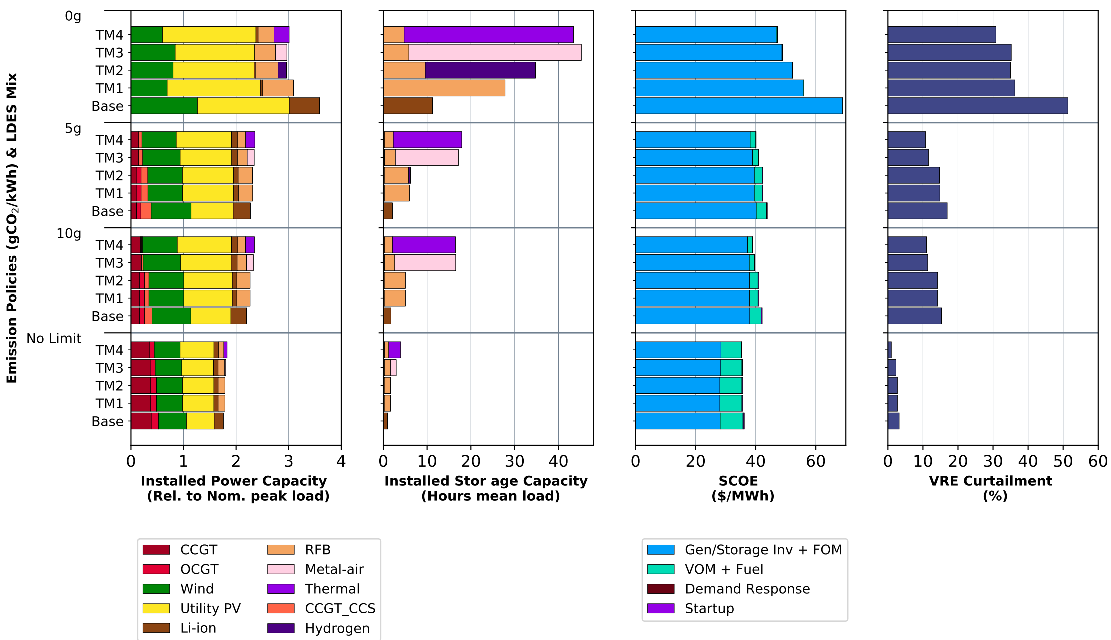

Figure 3-5: System summary results of experiment A, LDES technologies at medium costs, comparing technology mixes for various emission constraints. TM1 is Li-ion + RFB; TM2 is Li-ion + RFB + Hydrogen; Li-ion + RFB + Metal-air;

gas generation technologies (reduce the VOM component in the cost structure). As noted in the left panel of Figure3-5, for a given CO_2 emissions constraint, installed gas power capacity is substituted for VRE power capacity that produces energy at low cost to charge storage, which, in turn, is used for balancing purposes. This is evidenced by the decrease in VRE curtailments, in spite of the increase in VRE generation capacity.

Another effect of LDES is that it decreases instances of extremely high wholesale prices and also price volatility, for a given carbon emission constraint. In fact, as Figure3-6 shows, the price band of 5-50$/MWh increases with respect to the base case, shrinking the higher price band of 50-200, that generally correspond to natural gas generation. This directly impacts the unweighted average price (the simple arithmetic mean of the hourly marginal cost of generation) and in turn, with lower prices, volatility is reduced (table 3.3). Moreover, the role of LDES can be seen in the operational analysis by price band (Figure3-7), where RFB and Metal-air complement Li-ion by operating (delivering energy to the grid) more time at lower prices

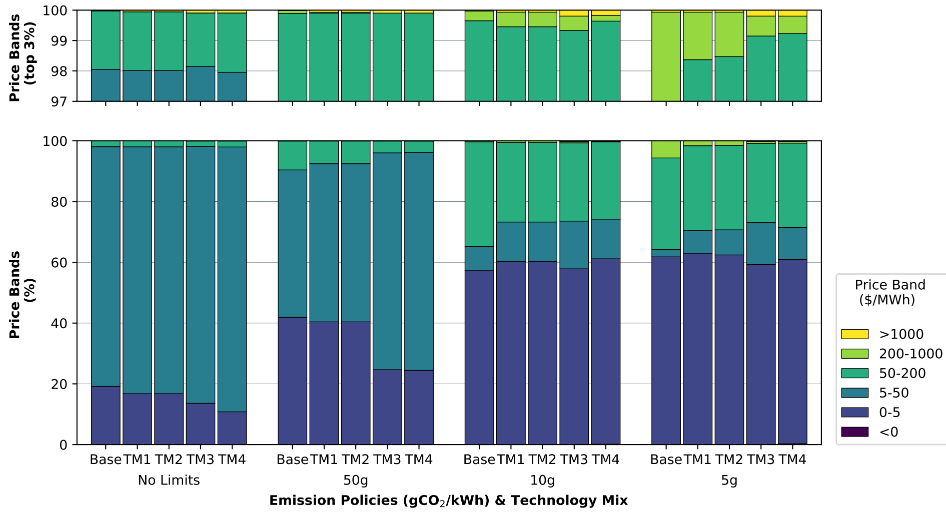

Figure 3-6: Prices distribution of experiment A with LDES technology cost projections at medium costs, comparing the Base Case with technology mixes for various emission constraints. TM1 is Li-ion + RFB; TM2 is Li-ion + RFB + Hydrogen; TM3 is Li-ion + RFB + Metal-air; and TM4 is Li-ion + RFB + Thermal. Negative prices are observed only in TM4, and account for a neglectable amount of hours.

and relying less on extreme prices for their break even. the mechanism is clear in particular for Metal-air, because it can store several hours of energy to be discharged continuously and therefore reducing system marginal value of generation over periods of low VRE resources, as can be seen in Figure

Emission policy (gCO2/kWh)	Average price					Price volatility (CoV)				
	Base case	TM1	TM2	TM3	TM4	Base case	TM1	TM2	TM3	TM4
1	49.8	42.7	42.2	39.6		7.1	7.7	7.8	6.8	
5	42.1	39.6	39.6	38.0	37.3	9.8	7.4	7.4	6.9	7.7
10	40.5	38.8	38.8	37.5	36.8	10.9	7.5	7.5	7.0	7.9
50	34.1	34.9	34.9	33.4	33.0	17.6	8.8	8.8	10.2	11.6
NL	31	31.4	31.4	31.4	31.3	18.3	12.5	12.5	12.3	12.7

Table 3.3: average price and price volatility. Experiment group A - medium cost projections.

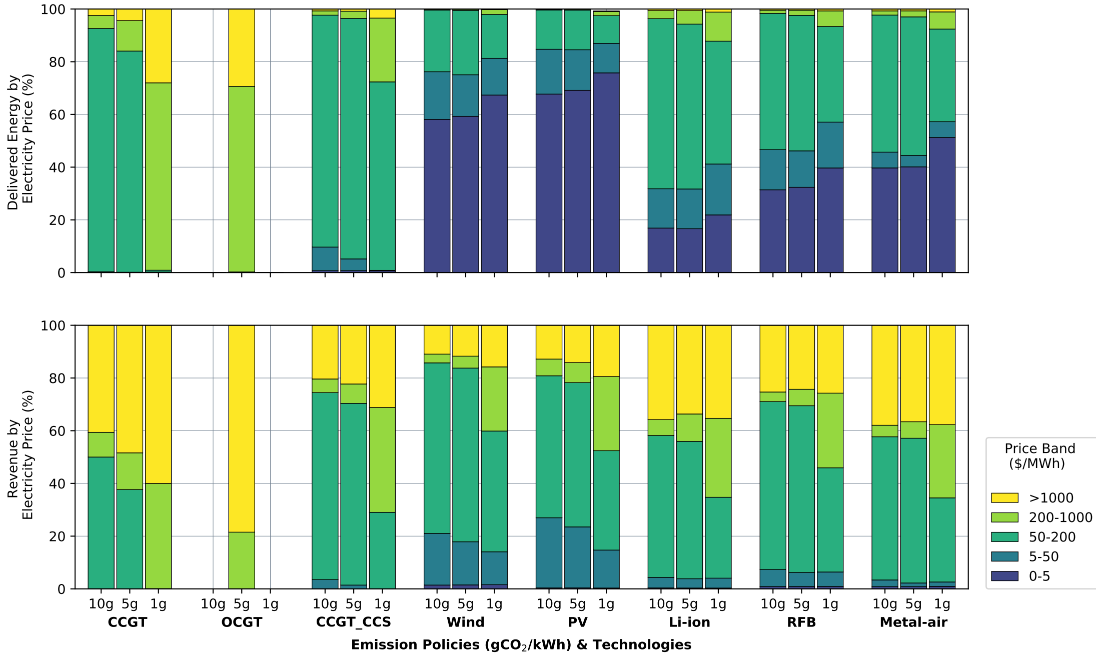

Figure 3-7: Experiment A, Technology Mix 3 (Li-ion + RFB + Metal-air) - Technology operation by price band (upper panel) and technology revenue by price band (lower panel), illustrating how technology rely on high prices to break even under deep decarbonization conditions.

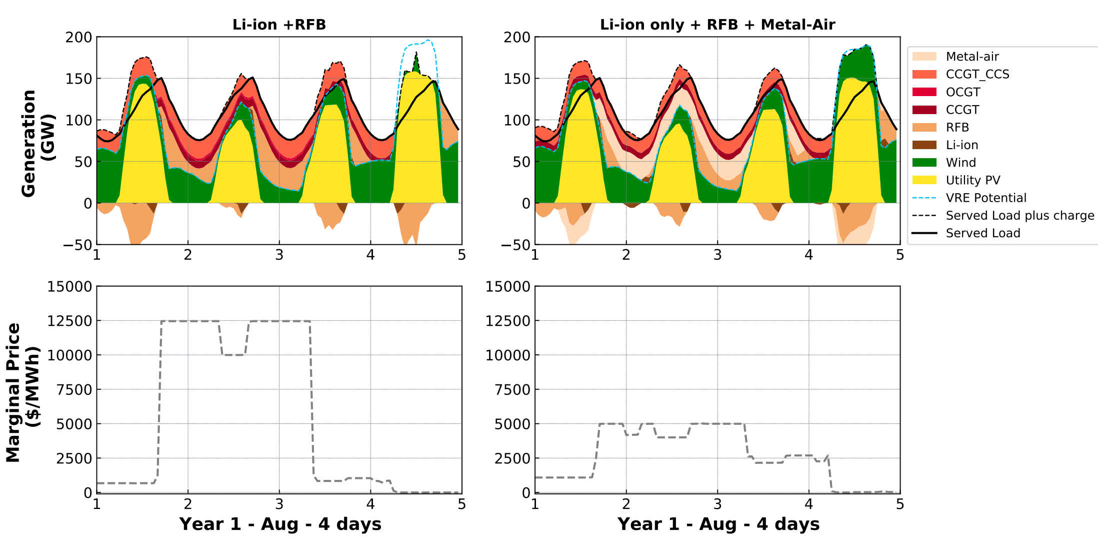

Figure 3-8: Experiment A, Technology Mix 1 v/s 3 operating over four days under low VRE potential and showing how Metal-air helps to decrease the marginal value of generation under extreme circumstances.

3.2.2 Long Duration Energy Storage - Cost Sensitivities

This section explores the system impact of alternative cost assumptions for different LDES and Li-ion storage technologies across the various CO_2 emissions policy scenarios. Results show that from an SCOE perspective, regardless of the cost sensitivity (high, medium or low) of energy storage technologies, LDES play a positive role in the system (decreasing SCOE and curtailments). Sorted by descending SCOE value at 0g, system summary is shown in Figure 3-9. SCOE can be reduced by up to 34% in the 0g and 12% in the 5g cases compared to the base case, reaching values of \$45/MWh and \$38/MWh, respectively, corresponding to scenarios with both Li-ion and RFB are at both its low-cost projection (TM5). Moreover, it can be noted that this price decrease is driven mostly by RFB being at low cost, since the difference in SCOE between TM7 (Li-ion (M) + RFB (L))and TM5 (Li-ion (L) + RFB (L)) cases is only \$0.1/MWh. TM11 and TM14 yield the same cost level as TM5, because Metal-Air and Hydrogen at the High-cost projections are substituted completely by RFB. The relative impact on key outcomes of each storage cost scenario with respect to the base case is shown in Table 3.4.

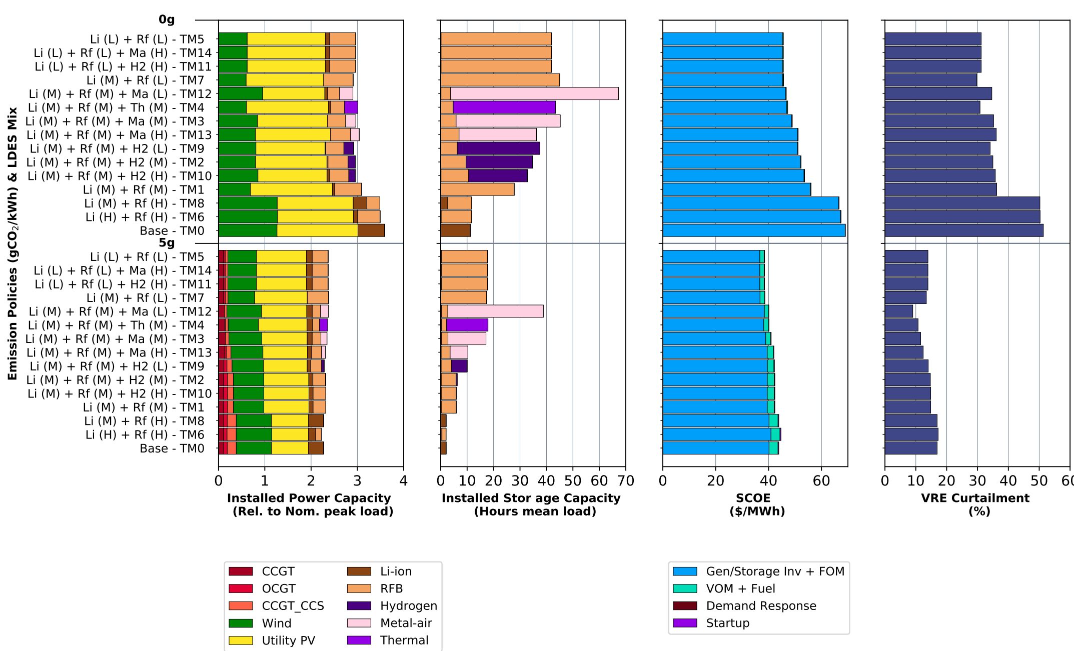

Figure 3-9: System summary results of experiment A, cost sensitivities of storage technologies.

On the cases where RFB and Li-ion at medium cost (TM's 2, 3, 4, 9, 10, 12,13), SCOE does not reach the low SCOE values that are achieved if RFB is at low costs. Therefore, regardless of the cost projections of Hydrogen, Metal-air and Thermal energy storage, RFB remains as the most impactful technology to reduce System average cost.

Regarding installed power capacity, the total required power capacity is fairly stable at 5g and also at 0g, once RFB is added at its medium cost level (TM1 and above). The main impact, nevertheless, is the substitution of natural gas generation for increased VRE capacity and reduced VRE curtailment. The decreasing gas generation capacity trend can be observed in Figure 3-9, on the left panel at 5g.

		0gCO2/kWh				**5gCO2/kWh**			
TM	Description	SCOE	Power Cap.	Storage Cap.	Curt	SCOE	Power Cap.	Storage Cap.	Curt
TM1	Li (M) + Rf (M)	-18.8	-14.0	147.6	-29.5	-3.3	2.2	189.2	-12.4
TM2	Li (M) + Rf (M) + H2 (M)	-24.2	-17.6	209.4	-31.9	-3.4	2.1	204.7	-13.0
TM3	Li (M) + Rf (M) + Ma (M)	-29.1	-17.4	302.8	-31.4	-6.5	3.3	736.1	-31.7
TM4	Li (M) + Rf (M) + Th (M)	-31.6	-16.2	286.9	-40.0	-8.5	3.9	773.8	-36.5
TM5	Li (L) + Rf (L)	-34.0	-17.4	273.5	-39.2	-12.4	4.4	766.8	-17.6
TM6	Li (H) + Rf (H)	-2.4	-2.8	4.7	-2.1	1.9	-2.1	-1.0	1.9
TM7	Li (M) + Rf (L)	-33.9	-19.0	301.4	-42.1	-12.0	4.7	749.3	-20.7
TM8	Li (M) + Rf (H)	-3.5	-2.9	4.9	-2.2	0.0	0.0	0.0	0.0
TM9	Li (M) + Rf (M) + H2 (L)	-25.9	-18.7	234.6	-33.6	-3.7	0.6	388.5	-17.0
TM10	Li (M) + Rf (M) + H2 (H)	-22.4	-17.7	192.2	-30.3	-3.3	2.2	189.2	-12.4
TM11	Li (L) + Rf (L) + H2 (H)	-34.0	-17.4	273.5	-39.2	-12.4	4.4	766.8	-17.6
TM12	Li (M) + Rf (M) + Ma (L)	-32.4	-19.1	499.1	-32.5	-8.6	4.6	1793.5	-46.7
TM13	Li (M) + Rf (M) + Ma (H)	-25.9	-15.3	222.9	-29.7	-4.2	1.8	402.3	-26.7
TM14	Li (L) + Rf (L) + Ma (H)	-34.0	-17.4	273.5	-39.2	-12.4	4.4	766.8	-17.6

Table 3.4: Experiment A - Changes in % with respect to the Base Case of SCOE, Installed Power Capacity, Installed Energy Storage Capacity and Curtailment.

A complete Table of results with the installed capacities, projected storage needs, cost breakdowns and prices distributions is included in B on page 111.

3.2.3 VRE Price Sensitivities

Capital costs of renewable energy are an important factor impacting the least-cost grid outcomes under various CO_2 emissions policy scenarios. For example, if Onshore Wind and Utility PV costs are modeled as per the low-cost projections (available from NREL ATB[22]), corresponding to 33 and 23% lower than the medium cost projections, the system average cost for the no limits policy case is reduced by 18% (considering only Li-ion at medium cost level - TM15) and CO_2 emissions intensity is

59 gCO2/kWh vs. 92 gCO2/kWh. Conversely, if VRE costs are higher than expected, SCOE can go up by 7% (TM23) as compared to the base case. Figure 3-10 and Table 3.5 present the system summary and the changes in main metrics for Experiment group B.

On top of this, if LDES are considered in the technology mix, System average cost can go down over 43% (TM21, Table 3.5) compared to the base case.

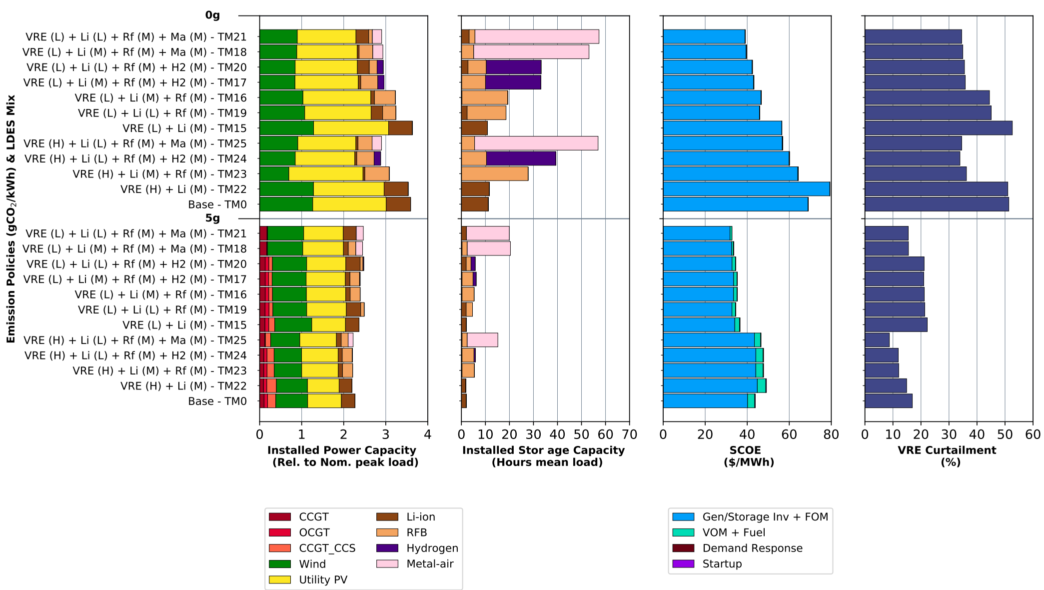

Figure 3-10: System summary results of experiment B, cost sensitivities of VRE technologies.

TM	Description	0gCO2/kWh SCOE	Power Cap.	Storage Cap.	Curt	5gCO2/kWh SCOE	Power Cap.	Storage Cap.	Curt
TM15	VRE (L) + Li (M)	-18.1	1.2	-3.2	2.4	-16.5	4.2	1.0	31.5
TM16	VRE (L) + Li (M) + Rf (M)	-32.3	-10.0	72.3	-13.4	-19.4	5.4	158.3	25.2
TM17	VRE (L) + Li (M) + Rf (M) + H2 (M)	-37.4	-17.6	194.9	-30.2	-19.5	5.4	201.0	24.1
TM18	VRE (L) + Li (M) + Rf (M) + Ma (M)	-42.5	-18.4	373.4	-32.0	-23.4	7.9	895.8	-8.2
TM19	VRE (L) + Li (L) + Rf (M)	-33.4	-9.7	65.5	-12.2	-21.2	9.6	125.7	26.2
TM20	VRE (L) + Li (L) + Rf (M) + H2 (M)	-38.4	-18.1	195.9	-30.8	-21.3	9.1	181.3	24.9
TM21	VRE (L) + Li (L) + Rf (M) + Ma (M)	-43.4	-19.2	410.5	-32.7	-25.3	8.7	872.3	-8.6
TM22	VRE (H) + Li (M)	15.0	-1.6	3.9	-0.7	12.1	-3.2	-9.6	-12.0
TM23	VRE (H) + Li (M) + Rf (M)	-6.8	-14.1	147.6	-29.4	9.0	-2.5	164.0	-28.7
TM24	VRE (H) + Li (L) + Rf (M) + H2 (M)	-12.9	-19.8	250.6	-34.0	9.0	-2.6	184.6	-29.6
TM25	VRE (H) + Li (L) + Rf (M) + Ma (M)	-17.6	-19.3	407.0	-32.7	6.2	-2.0	640.1	-48.4

Table 3.5: Experiment B - Changes in % with respect to the Base Case of SCOE, Installed Power Capacity, Installed Energy Storage Capacity and Curtailment.

The effect of low VRE capital costs on installed capacity depends on the CO_2 emission intensity constraint. At less stringent CO_2 constraints (see the 50gCO_2/kWh in Figure 3-11) for a given storage mix, the effect of increasing the cost of VRE is absorbed into the system average cost, keeping the deployed capacities almost unchanged from one another.

On more decarbonized systems (10g and 5g), the effect of VRE cost decline is to increase the installed renewable power capacity and natural gas capacity substitution. Conversely, at high VRE cost, gas generation increases and VRE capacity decreases compared to the base. The change in VRE costs has a smaller impact on the storage needs of the system.

In all cases, and as expected, curtailments decrease as VRE cost increase due to reduced installed power capacity and a better utilization of the asset (curtailment % decreases more than the installed VRE capacity).

On prices distribution, Figure 3-12, the effect of increasing VRE cost is that it reduces the lower band of prices and increases the upper bands.

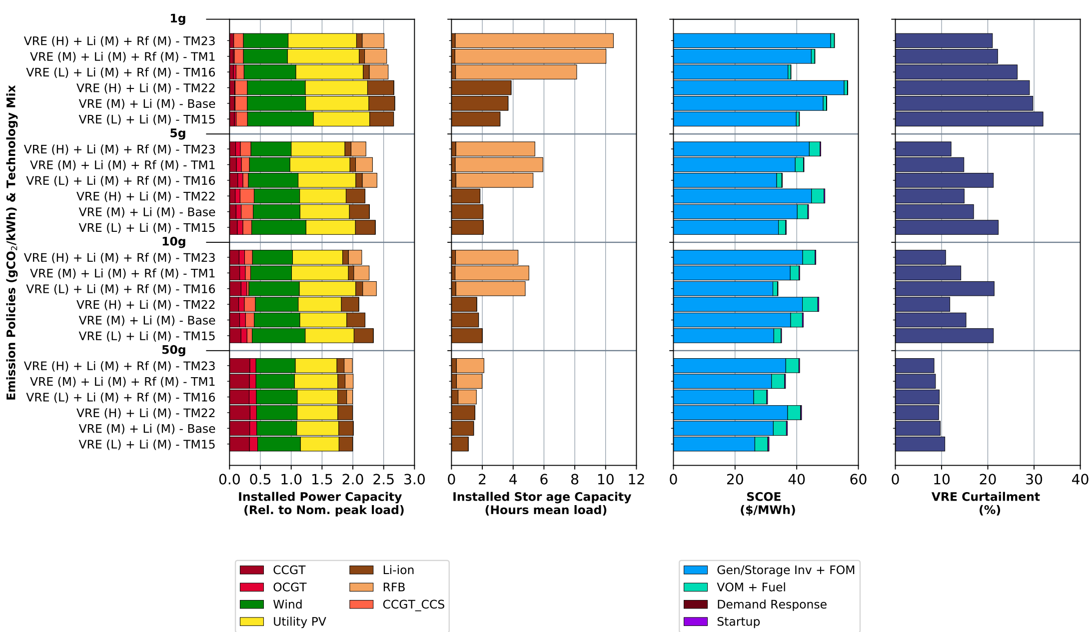

Figure 3-11: Combined results from Experiments A and B showing the effect of increasing VRE costs (Low - medium - high) for fixed storage mix: Li-ion only (M); Li-ion (M) + RFB (M).

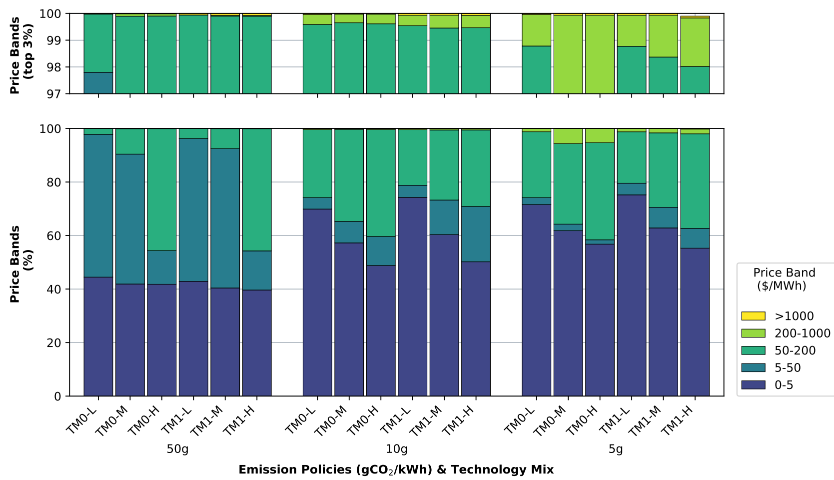

Figure 3-12: Experiment B: Prices Distribution showing the effect of increasing VRE costs (Low, Medium and High) for two technology mixes. TM0: Li-ion only (M); TM1: Li-ion (M) + RFB (M). and three carbon policy constraints.

3.2.4 Allam Cycle

The Allam Cycle [4] is a highly efficient, low-carbon, dispatchable generation technology that because of its high CO_2 capture rate and dispatchable operation, promises to contribute significantly to the decarbonization efforts of electrical grids. Figure 3-13 shows the system summary results with the system impacts of including Allam Cycle as an available technology. In particular, the effect of the Allam Cycle on three storage technology mixes is analyzed: Li-ion only (TM0 v/s TM26); Li-ion + RFB + Hydrogen (TM9 v/s TM27); and Li-ion + RFB + Metal-air (TM3 v/s TM31); for three carbon emission constraints: 1g, 5g and 10gCO_2/kWh.

Several effects are caused by the introduction of the Allam cycle in the system. First, natural gas generation (CCGT_CCS) is fully substituted by Allam cycle. Since Allam cycle is a low carbon dispatchable generation option, it reduces the needs of LDES as well as the relative economic value of VRE resources. Finally, SCOE is reduced with Allam cycle introduction, but only to a small extent (eg. 2% reduction in the 5g case). The quantification of these observations are summarized in Table 3.6. In Figure 3-14, can be observed how the generation of CCGT_CCS is substituted

[4] The Allam-Fetvedt Cycle or Allam Cycle is a supercritical CO_2-based cycle that is fueled with natural gas, with almost 100% CO_2 capture. For more details on the technology, refer to Wiland and White, NREL 2019 [27]

for Allam Cycle over days 1 to 3, and how storage is also substituted over days 7 to 9. In addition, it also can be seen how the VRE potential (how much could be generated at a specific point in time, given the installed capacity) is reduced, along with curtailments (curtailment is the area between the VRE potential and the Served load plus charge curves)

		Li-ion only			Li-ion + RFB + H2 (L)		
		No Allam	**With Allam**	**Change (%)**	**No Allam**	**with Allam**	**Change (%)**
Power (GW)	**CCGT**	15.9	19.6	23%	17.6	19.4	10%
	OCGT	12.7	13.7	8%	10.1	12.2	21%
	CCGT_CCS	29.3	0.0	-100%	16.6	0.0	-100%
	Allam	-	30.1	-	0.0	20.1	-
	Total Gas	57.96	63.43	9%	44.20	51.70	17%
	Wind	114.7	104.7	-9%	102.6	94.7	-8%
	Utility PV	121.1	109.1	-10%	142.7	137.2	-4%
	Total VRE	235.8	213.8	-9%	245.3	231.9	-5%
	Li-ion	49.1	38.1	-22%	11.7	10.5	-10%
	RFB	-	-	-	35.3	34.5	-2%
	Hydrogen	-	-	-	8.4	3.8	-54%
	Metal-air	-	-	-	-	-	-
	Total Stor.	49.1	38.1	-22%	55.3	48.8	-12%
Storage (GWh)	**Li-ion**	167.3	128.6	-23%	17.0	13.9	-18%
	RFB	-	-	-	319.7	307.2	-4%
	Hydrogen	-	-	-	480.5	220.8	-54%
	Metal-air	-	-	-	-	-	-
	Total Stor.	167.3	128.6	-23%	817.3	541.9	-34%
	Curt. (%)	16.9	12.4	-27%	14.0	11.6	-17%
	SCOE	43.9	42.8	-2%	42.2	41.7	-1%

Table 3.6: Effect of Allam Cycle on the electrical system under two storage mixes: Li-ion only and Li-ion + RFB + H_2 (L), at 5gCO_2/kWh. Allam Cycle increases the installed gas generation power capacity substituting for CCGT_CCS; reduces the installed VRE power capacity; reduces the need for storage capacity (power and energy); and reduces curtailments.

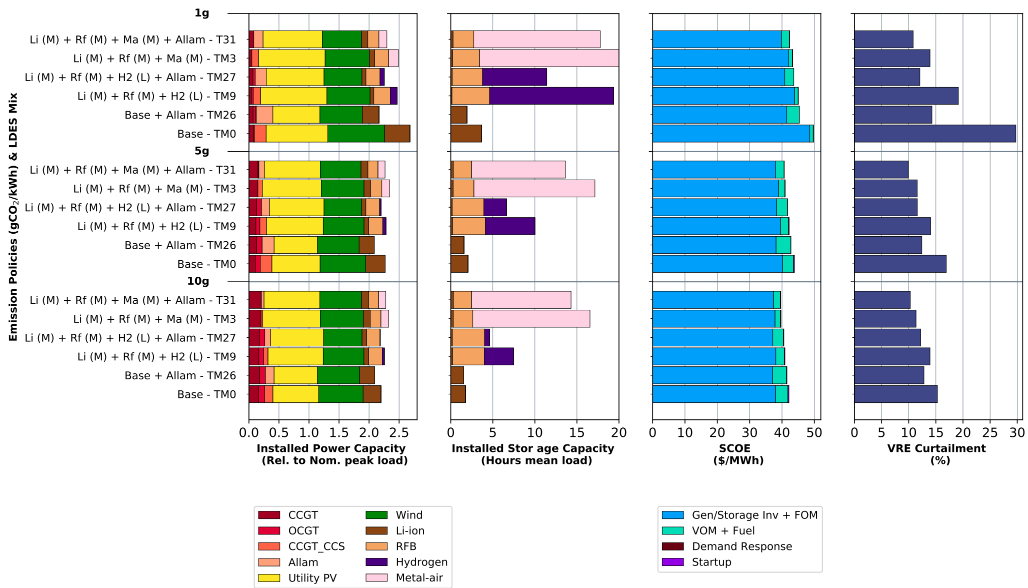

Figure 3-13: Effect of Allam Cycle on the power system, under different combinations of storage technologies and emission intensity constraints.

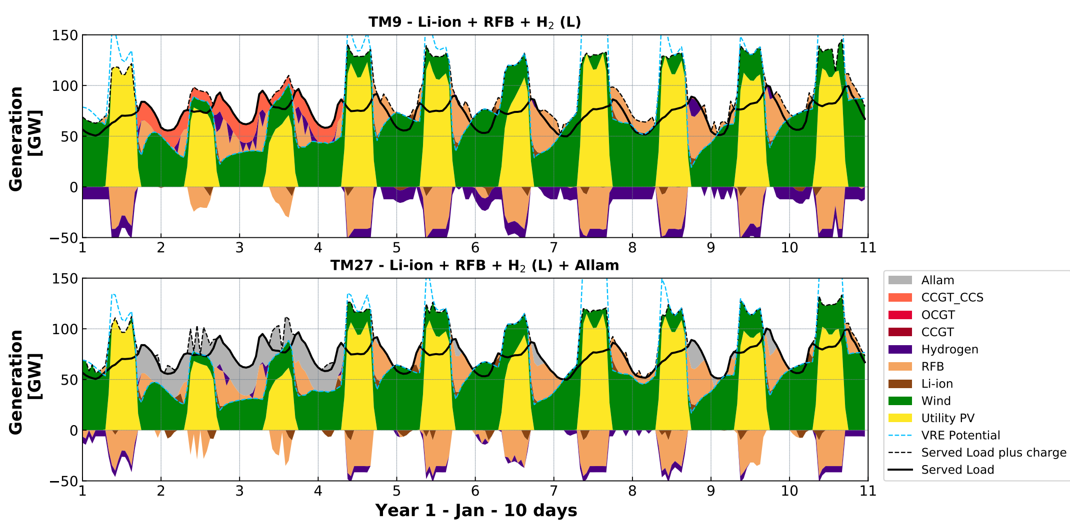

Figure 3-14: System Operation over 10 days in winter, showing the substitution effect of storage and CCGT_CCS for Allam cycle (both gas and storage substitution)

3.3 Impact Electrification level

This sensitivity corresponds to experiment group C and explores two possible electricity demand scenarios by 2050, based on NREL's Electrification Futures Study[1]: Reference Electrification (or Low for our purposes) and High Electrification (used as the Base Case in this work). Under the High Electrification Scenario, the total demand (and mean, in turn) increases by 32% (Table 2.1) compared to the reference demand scenario the load profile becomes 'peakier', mainly driven by the electrification of the transportation sector[5]. The comparison between main metrics is shown in Table 3.7 and to the increase in peakiness of the load profile is seen in Figure 2-9.

	Peak (GW)	Mean (GW)	Total (TWh)	CoV (-)	Max. daily peak
EFS Reference 2050	110.7	62.1	543.5	0.24	1.33
EFS High 2050	151.1	81.6	715.1	0.26	1.47
% Increase Ref. - High hline	36%	32%	32%	7%	11%

Table 3.7: Comparison between NREL's Electrification Future Study projections for 2050 [1]. Max. daily peak is the maximum ratio between the daily peak load to the daily mean load.

Figure 3-15 highlights the sensitivity of system outcomes to changes in demand, where observe that high electrification scenarios tend to improve the economic value of VRE resources by reducing VRE curtailment. To understand this effect, Figure 3-17 and 3-16 highlights the system dispatch for high electrification and reference demand scenarios across a few days in summer and winter periods, respectively. In summer, the peak load is coincident with periods of high VRE potential and thus curtailments are reduced (Figure3-17). In winter, however, this is not the case, but the mismatch between load and VRE potential is small and usually satisfied with storage operation.

The alignment of the system peak with the VRE potential curve bring benefits to the overall system performance. First, the total required installed capacity with respect to the peak load is less in the High Electrification than in the Reference

[5]In the high electrification scenario, the maximum ratio of the max daily load to the average daily load is 1.47, whereas in the reference this ratio is 1.33, similar to the observed ERCOT level in years 2018 to 2021

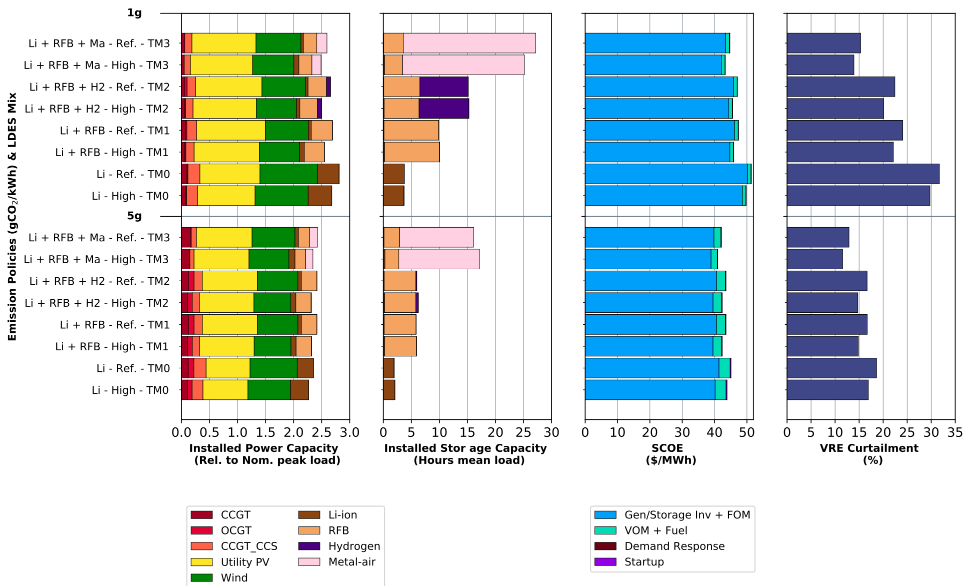

Figure 3-15: Comparison of System Summary between the Reference and High Electrification scenarios, for three storage mixes and two emission constraints.

Electrification and lower curtailment levels. The better asset utilization leads to lower SCOE in the High electrification scenario as well, because the required total investment plus operational costs are less than the 32% increment in the system load.

Figure 3-15 also highlights that the impact of electrification on energy storage capacity deployment is not as significant as the other metrics. This is mainly because storage plays the balancing role after the peak of VRE generation, which occurs after sunset. Arguably, if the peaks due to electrification are not coincident with the VRE potential availability, the impact of electrification won't be as favorable as in this particular case. Therefore, this finding may not be generalizable to other regions.

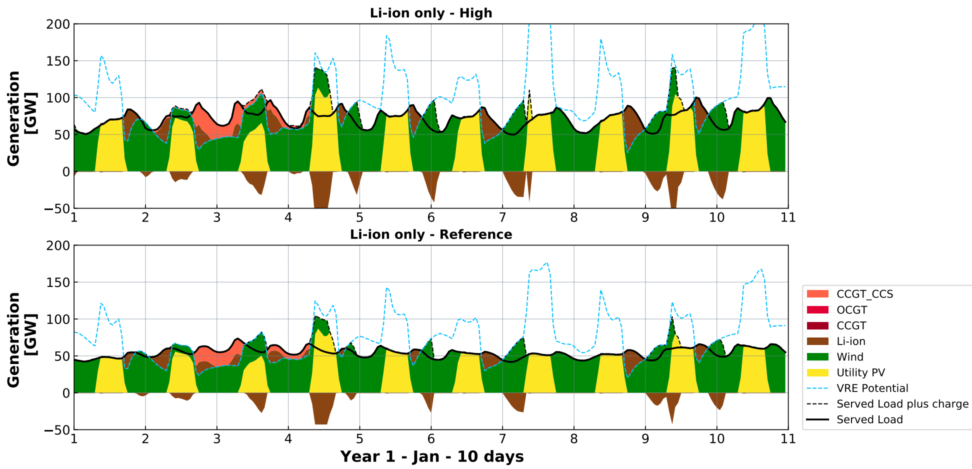

Figure 3-16: System Operation over 10 days in winter, showing how storage helps in covering the peaks caused by electrification. As the light hours are reduced, the peak lies at the right of the VRE potential curve.

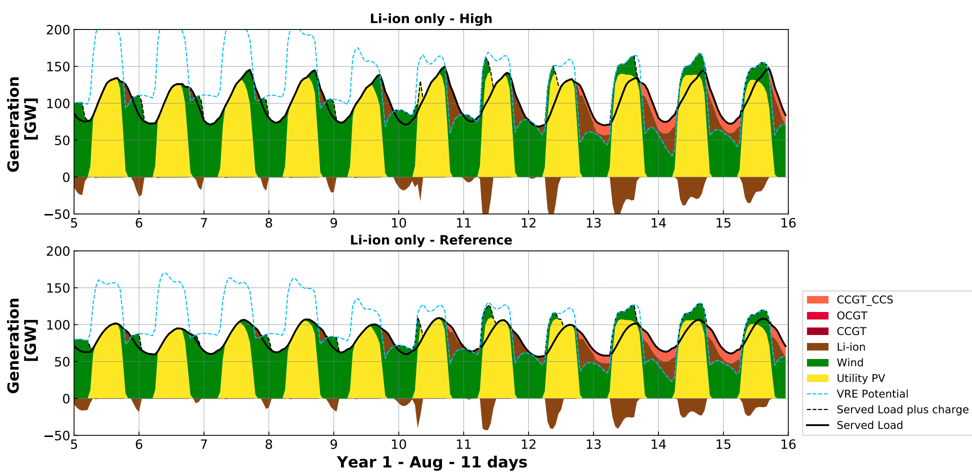

Figure 3-17: System Operation over 10 days in summer, showing how the increase in electrification is coincident with high periods of VRE potential (days 5 to 13).

3.4 Impact of Demand Flexibility

Demand Flexibility, defined as the capability of load being shifted in time, can help to modulate the load profile to reduce system peaks and therefore improve capacity utilization and reduce the overall generation capacity requirements to satisfy demand. Results for experiment set D explore the potential for demand flexibility to impact system outcomes based on the technical limits defined in Table 2.8 [1] and with the assumption of demand being potentially shifted in time at no cost.

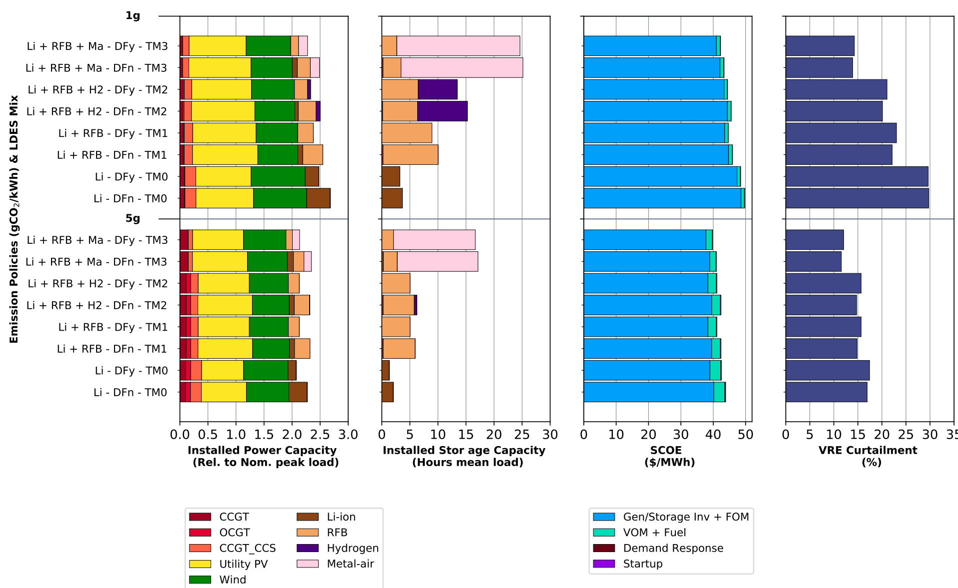

Figure 3-18: Effect of demand-side flexibility on Texas electrical system, under three storage mixes and the 5g and 1g CO_2 emission intensity constraints. When comparing the cases with demand flexibility enabled (DFy) and the ones without (DFn), it can be observed that the main substitution effect is replacing Li-ion.

Since the defined demand flexibility can shift load over a period of hours, it substitutes for short-term storage resources such as Li-ion under cost-optimal capacity planning and dispatch, rather than LDES (LDES are displaced as well, but in a lower magnitude). This substitution effect is evidenced in Figure 3-18, where on the power and energy storage capacity panels if demand flexibility is enabled (bars with DFy labels), Li-ion installed capacity gets reduced up to 100% in the cases where it is in combination with other LDES like RFB. This reduction of installed storage, in turn, reduces the SCOE of the system by an average of 3% compared to the base case, for various storage technology scenarios explored in Figure 3-18.

Natural gas generation capacity is not affected to a great extent by implementing demand flexibility, and VRE generation is almost not affected. These results are summarized in Table 3.8, where the results of the case of Li-ion only (TM0) and Li-ion + RFB + Metal-air (TM3) are compared at a $5gCO_2/kWh$ emission intensity. From an operational perspective, Figure 3-16 shows the effect of demand-side flexibility on the system operation over 6 winter days, under the $5gCO_2/kWh$ emission intensity policy and Li-ion + RFB +Metal-air (TM3) storage mix. The lower panel shows how demand flexibility helps to avoid load peaks outside the zone of high VRE generation potential by shifting them inside that zone and therefore eliminating the need for Li-ion and reducing the need for Metal-air as well.

Although the summer peak load is over 50% higher than the winter peak load, as the summer peaks occurs mostly inside the high VRE generation potential zone, the overall impact of demand flexibility is similar in winter and in summer. The extent to which demand flexibility is used over the year is shown in Figure 3-20 as the black line. It can be noted that in spite of the higher Demand Flexibility potential in summer (blue line), demand flexibility is used similarly as in winter (peaks of around 30GW). This unused potential of demand flexibility is because the load peaks in summer are more aligned with the VRE generation potential profile. Therefore, the consequence is that the overall reduction in SCOE is only 3% under the effect of demand flexibility. Arguably, under different load and VRE potential profiles, the impact of demand flexibility could be different than what is observed in this Texas case study.

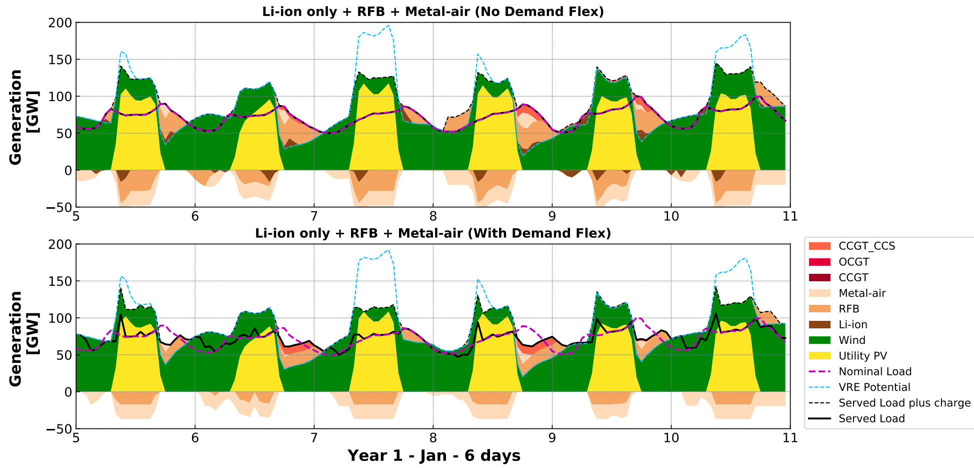

Figure 3-19: Effect of demand-side flexibility on the system operation over 6 winter days, under the $5gCO_2/kWh$ emission intensity policy and Li-ion + RFB +Metal-air (TM3) storage mix. The lower panel shows how demand flexibility helps to avoid the peaks outside the zone of high VRE generation potential by shifting them inside that zone and therefore eliminating the need for Li-ion and reducing also the need for Metal-air.

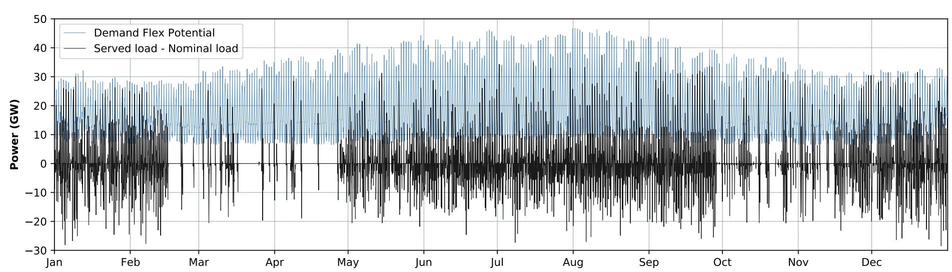

Figure 3-20: Hourly load difference between Nominal Load and served demand accounting for demand flexibility, under the $5gCO_2/kWh$ emission intensity policy and Li-ion + RFB +Metal-air (TM3) storage mix. Differences between served and nominal load (black line) in winter and in summer are relatively similar, in spite of the higher summer potential (blue line). In spring and Fall, Demand Flexibility is used to a lesser extent.

		Li-ion only			Li-ion + RFB + Metal-air		
		No Dem. Flex.	With Dem. Flex	Change (%)	No Dem. Flex.	With Dem. Flex	Change (%)
Power (GW)	**CCGT**	15.9	16.0	0%	22.6	22.7	0%
	OCGT	12.7	13.1	3%	0.1	0.2	72%
	CCGT_CCS	29.3	29.5	0%	11.2	11.5	2%
	Total Gas	58.0	58.5	1%	33.9	34.3	1%
	Wind	114.7	119.9	5%	107.6	114.6	7%
	Utility PV	121.1	112.9	-7%	148.0	136.9	-8%
	Total VRE	235.8	232.8	-1%	255.6	251.6	-2%
	Li-ion	49.1	21.9	-55%	16.4	0.0	-100%
	RFB	-	-	-	28.3	17.2	-39%
	Metal-air	-	-	-	19.9	19.4	-2%
	Total Stor.	49.1	21.9	-55%	64.6	36.7	-43%
Storage (GWh)	**Li-ion**	167.3	109.1	-35%	23.3	0.0	-100%
	RFB	-	-	-	202.0	170.3	-16%
	Metal-air	-	-	-	1173.7	1190.0	-
	Total Stor.	167.3	109.1	-35%	1399.0	1360.3	-3%
	Curtailment	16.9	17.4	3%	11.6	12.1	4%
	SCOE	43.9	42.5	-3%	41.0	39.8	-3%

Table 3.8: Comparison of the effect of demand-side flexibility on the power system, comparing two storage mixes under the $5gCO_2/kWh$ emission intensity policy: Li-ion only and Li-ion + RFB +Metal-air. With demand flexibility, Li-ion is the technology that gets substituted the most.

3.5 Value of Lost Load

In most of our scenarios, we set the value of lost load (VoLL) to be relatively high at \$50,000/MWh to minimize load shedding events across scenarios and to provide incentives to the investment in more capacity to meet demand within the energy-only market framework implemented in GenX. Despite this, in some cases, we do observe load-shedding events that account for a small fraction of the total demand of the seven years of simulation. The maximum amount of load being shed, expressed by the total Non Served Energy (NSE, in GWh) by experiment group, is listed in Table 3.9. As expected because of the high VoLL, the total NSE represent a small amount of total demand, with the maximum value close to 0.001% of the nominal load.

In spite of the good results of the \$50,000/MWh VoLL, higher values were explored: \$100,000/MWh and \$200,000/MWh to understand if reducing these small events of load shedding have a relevant impact on the system or not. Results in Table 3.9 show that in Experiment group F all the events are removed (this is also true for cases with demand flexibility), meaning that between VoLL of \$50,000/MWh and \$100,000/MWh, NSE events can be fully eliminated.

The impact on the system is not relevant, as the installed power and storage capacity, along with SCOE and curtailment levels, remain almost unchanged. The largest change is at the No Limits policy for TM0 (the Base Case). On that scenario, VRE capacity and Li-ion storage increase to cope with the hours when the system decided to shed load. Figure 3-22 illustrates how the system dispatch is modified with increasing VoLL and eliminates NSE events that were observed at VoLL of \$ 50,000/MWh.

Experiment Group	ExpA	ExpB	ExpC	ExpD	ExpE	ExpF	ExpG
Max NSE (GWh)	13.98	19.99	20.90	0.00	13.98	0.00	49.67
Max NSE (%)	0.00028	0.00040	0.00055	0.00	0.00028	0.00	0.00099

Table 3.9: Maximum amount of load shedding per experiment group, expressed both in total GWh fo Non-Served Energy (NSE) in the 7 years of the model and as a percentage of nominal demand.

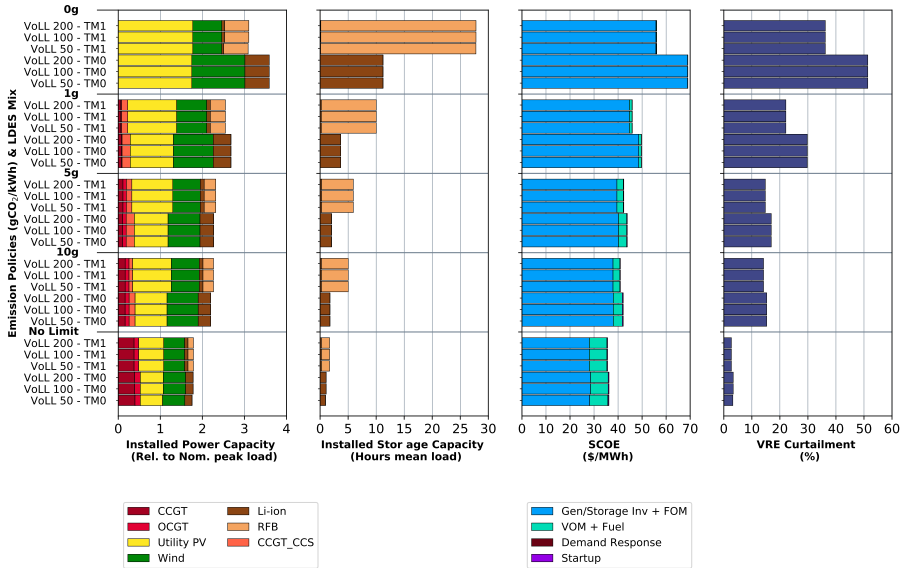

Figure 3-21: System Summary of experiment group F, comparing the impact of increasing the VoLL for TM0 and TM1 across various emission intensity policies.

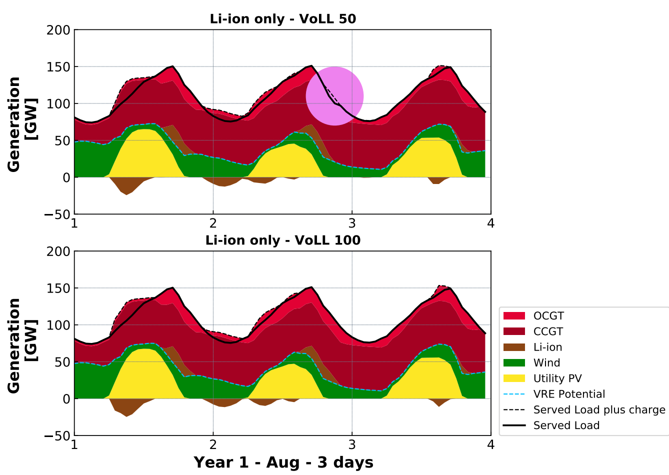

Figure 3-22: Example of how a non-served energy event of 13.98 GWh at the end of day 2, highlighted in the top panel with a pink circle (the worst event in the experiment group A) is resolved by increased capacity deployment under the higher VoLL scenario. The example corresponds to the base case at the No Limits policy scenario, comparing the $50,000/MWh and $100,000/MWh scenarios.

3.6 Impact of Hydrogen in Industry

While prior sections have focused exclusively on the impact of power system-specific drivers on grid decarbonization outcomes, in the case of LDES technologies involving H_2 storage, co-existence of non-power uses of H_2 could also prove to be valuable. This section explores the results of coupling the power sector with the industry via supplying hydrogen generated via electrolysis. The methodology and model setup is described in section 2.2.6.

This model setup can be seen as a special case of demand flexibility, where electricity-based H_2 production with electrolysis can be flexibly scheduled thanks to the availability of relatively low-cost H_2 storage capability, even though industrial H_2 demand is modeled to be constant and inflexible across all hours of the year. The impact of such a large flexible electricity demand has notable system impacts from four points of view: installed power and energy capacity mix, VRE curtailment levels, SCOE and marginal hydrogen production costs.

From the installed capacity perspective, findings show that for a given CO_2 emissions intensity constraint, increased industrial hydrogen demand with incremental hydrogen produced using flexible electrolysis favors deployment of VRE generation and displaces gas generation (both with and without carbon capture and storage (CCS)) and Li-ion power capacity (Figure 3-23). For example, in the 5 gCO_2/kWh scenario, Li-ion and gas power capacities with 100% of baseline industrial hydrogen demand are 10% and 23% lower than the case without any industrial H_2 demand (0% case).

Inclusion of industrial H_2 demand reduces the percentage increase in power capacity required to achieve increasingly stringent CO_2 emissions constraints relative to the no emissions limits policy case. Whereas without hydrogen demand, installed power capacity needs to increase 53% from the no limits case to the 1gCO_2/kWh case, with hydrogen demand the required increase is 35% on average. This reflects the increased capacity utilization of power generation capacity under scenarios with industrial hydrogen demand. Notably, across emission intensity constraint scenarios,

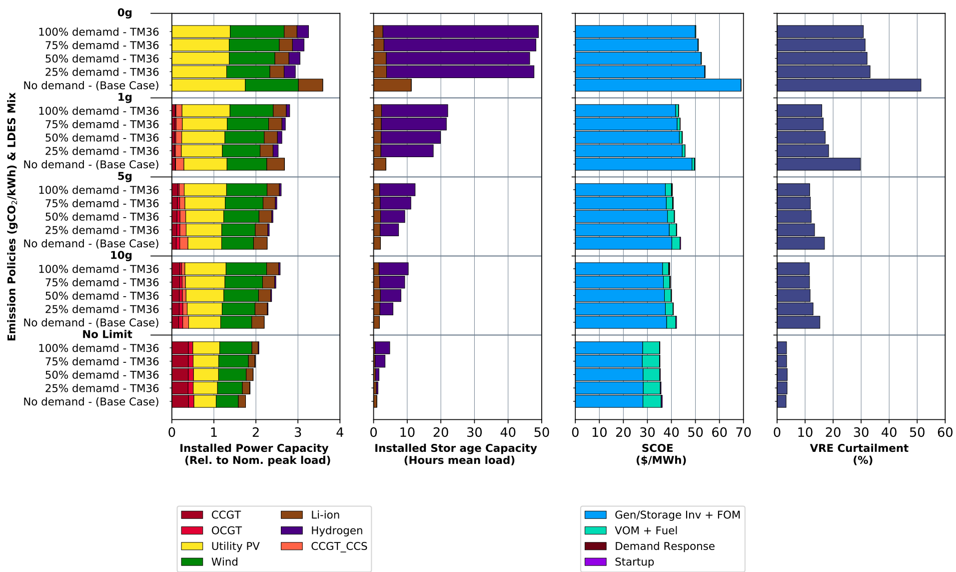

Figure 3-23: System Summary of experiment G, considering tank storage for hydrogen (TM36) and various levels of hydrogen demand in the industry.

VRE curtailment is on average 30% lower when serving 100% of industrial hydrogen demand compared to the base case (46% lower in the 1g CO_2/kWh case).

The impact of industrial demand for hydrogen on SCOE can be viewed from two perspectives: (1) For a given emission intensity policy, SCOE decreases as the H_2 demand increases and (2) for a given H_2 demand level, the increase in SCOE needed to decarbonize the power system starting from the No Limits case, is lower than the case without H_2 demand. Indeed, with 100% hydrogen demand and in the 5g case, SCOE is reduced by 8% with respect to the Base Case. Moreover, the increment in SCOE from the No Limits policy is 15%. which is significantly less than the 27% increase in the Base Case.

To explore more broadly the potential of hydrogen in a system where industrial demand for heat is partially met by hydrogen supply, underground geological storage was incorporated as a potential technology that could be deployed by the model (described as the Ultra-low cost assumptions in Table 2.5). The main difference between geological and tank storage is the investment needed per unit of stored energy (84% less compared to the mid-level cost projections). Findings show a positive effect on SCOE and curtailment of geological storage (Figure3-24). Table 3.10 provides

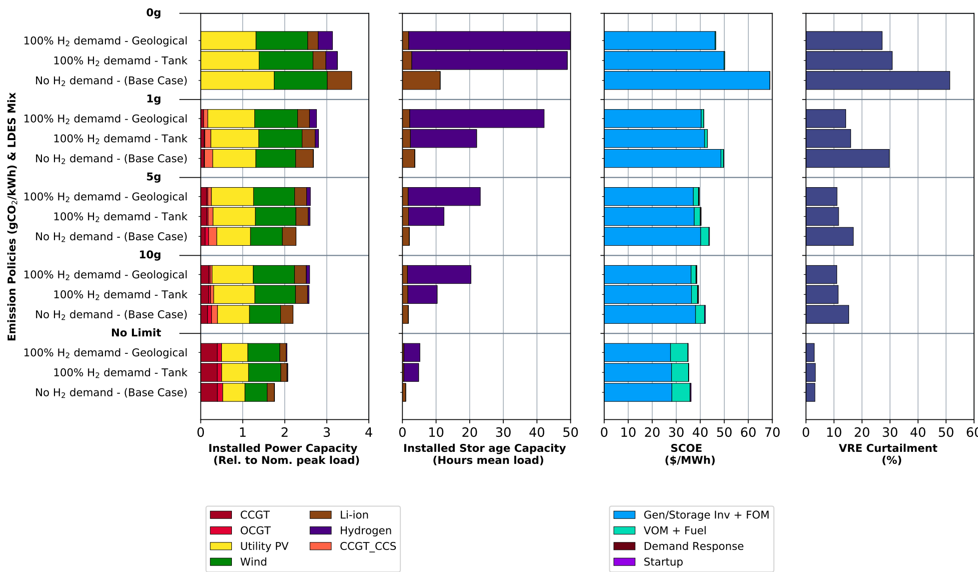

Figure 3-24: System Summary of experiment G, showing the comparison of results of tank and geological underground storage and the Base Case.

the summary of the changes in the main metrics of the system, both for tank and geological storage, with respect to the base case for the 5g and 1g emission policies.

In line with the trend observed in experiment group A, where lower cost of storage capacity led to positive effects on the system. At the 5 gCO_2/kWh case, availability of geological hydrogen storage results in an 10% decrease in SCOE (with respect to the base case), 33% decrease in NG capacity, 11% decrease in VRE curtailments and 27% increase in VRE capacity.

Hydrogen demand has an impact on prices distributions (Figure3-25), which can be described, on the one hand, as to reduce the amount of hours at low prices (band $0-5). At the same time, it also has the effect of reducing the extreme prices by mainly increasing the band $50-200 (except in the 0g case, where the number of hours at extreme prices actually increase).

3.7 Impact of Demand Response

This section develops the results of the demand response factor. Demand response (DR) differs from demand flexibility (DF) in that DR is about the system paying a

		Gas power capacity	VRE power capacity	Storage power capacity	Energy storage capacity	SCOE	Curtailments
$1gCO_2/kWh$	Tank storage	-16%	10%	-7%	501%	-14%	-46%
	Geological storage	-41%	8%	7%	1047%	-17%	-52%
$5gCO_2/kWh$	Tank storage	-23%	26%	4%	503%	-8%	-31%
	Geological storage	-33%	27%	15%	1030%	-10%	-34%

Table 3.10: Change in main metrics with respect to the Base Case (in %), comparing Tank and underground geological storage for the 1g and 5g cases.

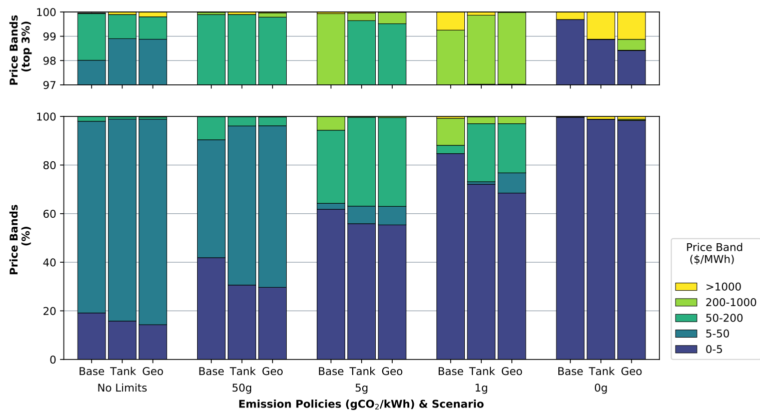

Figure 3-25: System Summary of experiment G, showing the comparison of results of tank and geological underground storage on prices distribution, at a 100% Hydrogen demand level.

price for load shedding. The amount of demand that can be shed will depend on the price point at which customers are willing to stop consuming and receive a payment for this service. Conversely, DF is demand shifting (without cost in this model) over time and demand is always met.

To understand the impact of DR, we simulated the impact of the demand response curve shown by Figure2-11, with demand starting to react at a price point of \$2,500/MWh. Recalling the prices distributions from experiment group A, the number of hours per year on which the price is above \$1,000/MWh is a small fraction, usually between 0 and 3% of total hours. Therefore, the points in time when DR will actuate are few. However, the impact is not as small as one would expect. As shown in Figure2-11, DR helps to decrease the total investment in power and storage capacity (except storage capacity in TM4, 5g and 0g cases), and in turn reduces the average system cost (SCOE), having its greatest impact in the 0g case. This is as expected, because the 0g case has the largest amount of hours with extreme prices.

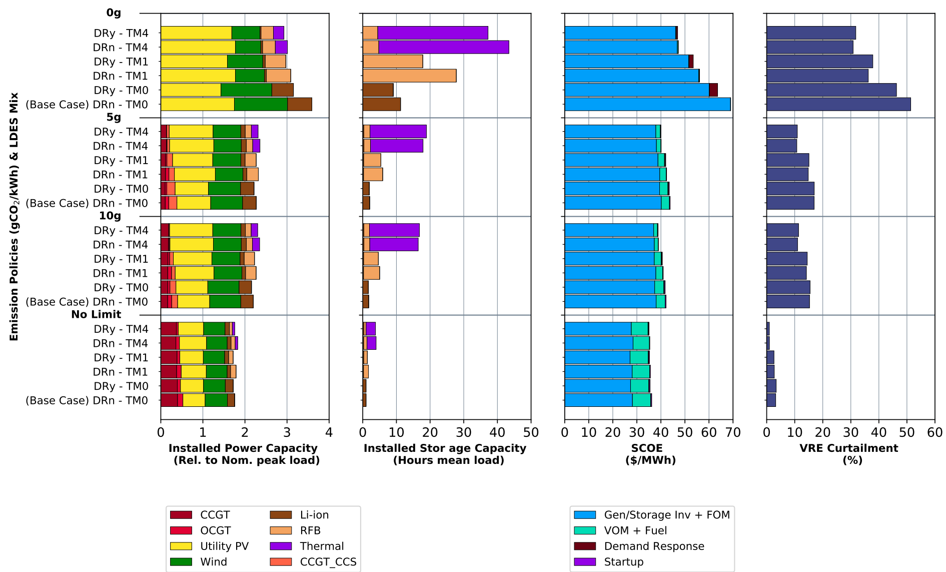

Figure 3-26: System Summary of experiment I, comparing the results of Demand response with the Base Case. TM0: Li-ion only; TM1: Li-ion + RFB; TM2: Li-ion + RFB + Thermal Storage

Nonetheless, DR is active in all cases. In short, DR is a substitute for natural gas and VRE generation.

The effect of DR on storage technologies is mixed: generally, DR tends to increase the installed power capacity of Li-ion, while always decreases the power capacity of RFB and Thermal storage. The same does not hold for energy storage capacity. With except of the 0g case, thermal storage capacity increases, while RFB storage capacity decreases in all cases (17% on average). Li-ion energy storage capacity shows mixed results: in some cases increases and in others decreases.

For an overview of the magnitude of the impact of demand response, a summary of TM1 is shown in Table 3.11.

As an illustrative example of Demand response performing, Figure3-27

		TM1: Li-ion + RFB (5g)			TM1: Li-ion + RFB (0g)		
		No DR	With DR	Change (%)	No DR	With DR	Change (%)
Power (GW)	CCGT	17.0	17.3	2%	0.0	0.0	-
	OCGT	12.2	4.8	-61%	0.0	0.0	-
	CCGT_CCS	19.6	20.3	3%	0.0	0.0	-
	Total Gas	48.8	42.4	-13%	0.0	0.0	-
	Wind	99.2	101.0	2%	107.6	114.6	7%
	Utility PV	147.0	144.2	-2%	148.0	136.9	-8%
	Total VRE	246.2	245.2	0%	255.6	251.6	-2%
	Li-ion	13.8	15.3	10%	16.4	0.0	-100%
	RFB	41.5	39.7	-4%	28.3	17.2	-39%
	Total Stor.	55.3	55.0	-1%	44.7	17.2	-61%
Storage (GWh)	Li-ion	20.2	22.7	12%	7.1	12.1	71%
	RFB	463.8	416.7	-10%	2261.4	1444.1	-36%
	Total Stor.	483.9	439.4	-9%	2268.5	1456.2	-36%
	Curtailment (%)	14.8	15.1	2%	36.2	37.8	4%
	SCOE ($/MWh)	43.9	42.5	-3%	41.0	39.8	-3%

Table 3.11: Comparison of results of demand response for TM1 at 5g and 0gCO_2/kWh

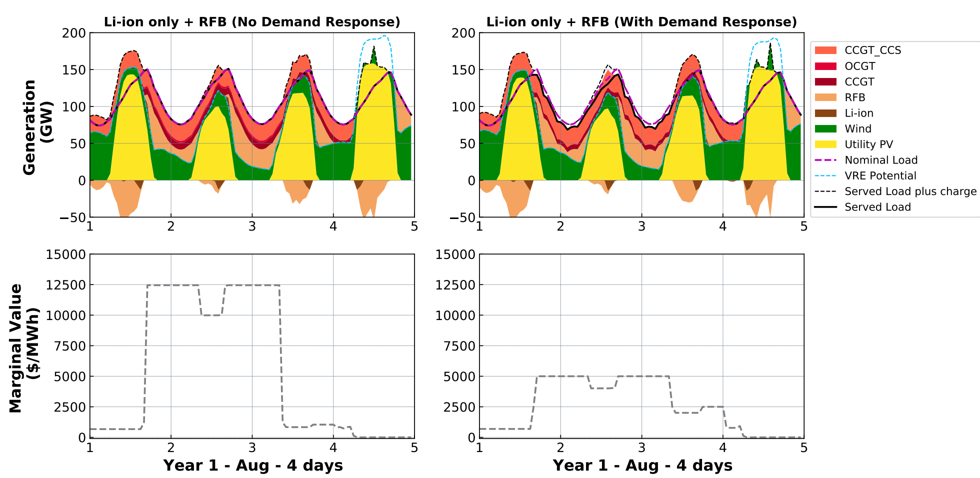

Figure 3-27: System operation and prices, showing TM1 case (Li-ion + RFB) operating at 1gCO_2/kWh, with and without Demand Response and the impact on system marginal value of generation.

3.8 Operation of Storage

The modeling highlights the differing operating patterns of various classes of storage technologies' that is influenced both by its individual storage technology attributes and system conditions (e.g. level of CO_2 emissions reduction). Figure 3-28 shows how frequently the storage resource is cycled (deep discharge and charge cycle) in our model of the deeply decarbonized Texas system with Li-ion and Hydrogen as the available storage technologies. As expected, Li-ion batteries, with relatively low power cost, relatively high energy capacity cost, and high round-trip efficiency (RTE) optimally focus on short-cycle operations, while hydrogen systems, with higher power costs but much lower energy capacity costs and RTE than Li-ion, focus on longer-cycle operations. These operational modes are not exclusive to each storage, however, and we see that Li-ion sometimes performs relatively long charge/discharge cycles, while hydrogen sometimes cycles rapidly. Moreover, the operating pattern of storage technologies is also influenced by the CO_2 emissions constraint: tighter constraints lead to longer cycles: compare the top and bottom portions of Figure 3-28.

As discussed in (Junge, Mallapragada and Schmalensee 2021 [2]), storage technologies do not follow simple cycling patterns. Optimal operation is more complex than the marginal cost dispatch rule for generation technologies. In effect, the marginal cost of using storage dispatch changes from one period to the next and is partly to explain for this complex operating behavior.

Frequency analysis [6] applied to the time series of the state of charge of storage technologies is a useful way to unpack complexity and quantify operating behavior, since it is able to quantify the relative importance of different frequencies (or cycling patterns) in the modeled storage state of charge. The results of the FFT analysis, applied to the model outputs related to storage state of charge variables shown in Figure 3-28, are listed in Table 3.12. It shows that for 10g CO_2/kWh case, Hydrogen storage behaves mostly in cycles that occur within a month (intra-month charge

[6] Frequency analysis is performed by applying the Fast Fourier Transform (FFT) to the time-dependent mode variable corresponding to the storage state of charge for each modeled period. Next, the root-mean-square (RMS) contribution of selected frequency bands is computed

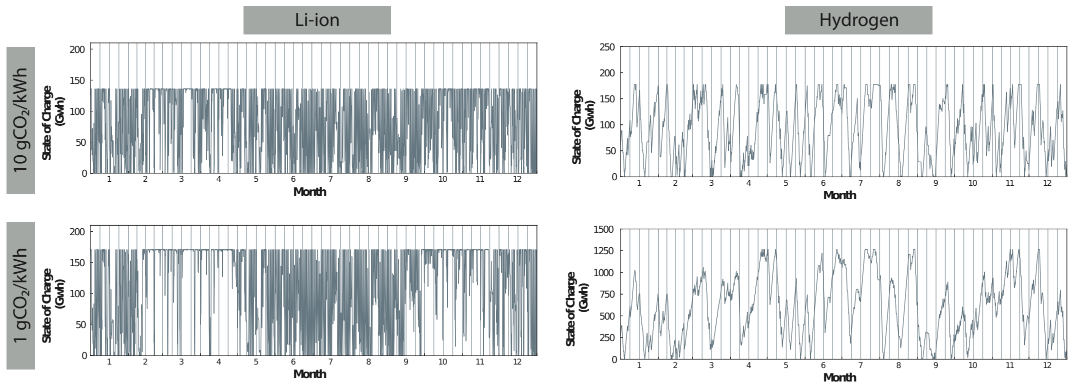

Figure 3-28: Example State of Charge (SoC) of Li-ion and Hydrogen systems in Texas. Scenarios show the SoC time series for the scenario with Mid-cost Li-ion, RFB, and Hydrogen across two emission policies. Here, we show 12 months of operation.

and cycle) and at the 1g CO_2/kWh case, the cycles decrease in frequency and become mostly seasonal (64%). Conversely, Li-ion shows a tendency towards daily and weekly cycles. In the 10g CO2/kWh case, daily and weekly charge and discharge cycles account for 73% of the operational patterns, but only 52% in the 1g CO2/kWh case. It is worth highlighting that Li-ion in the 1g CO_2/kWh case also displays a significant proportion of seasonal cycling (35%), reflecting the fact that over some periods of the year this technology is used less frequently than during others.

Frequency band	Mode of operation	10 gCO2/kWh		1 gCO2/kWh	
		Li-Ion	H2	Li-Ion	H2
Above 365 cycles/year	Daily	39%	1%	23%	0%
52 to 365 cycles/year	Weekly	34%	15%	29%	4%
12 to 52 cycles/year	Monthly	12%	59%	12%	32%
0 to 12 cycles/year	Seasonal	16%	25%	35%	64%

Table 3.12: Relative root-mean-square (RMS) contribution of different frequency bands to the storage's State of Charge

Chapter 4

Analysis & Conclusion

4.1 Wrap-up Analysis

Chapter 3 provided a detailed analysis of the effect that each decarbonization factor has on the power system. The impact was analyzed from different perspectives: the installed power and energy storage capacity (both the change in the technologies installed and the total power/storage capacity); system average cost (SCOE); curtailments; prices distributions; and operational patterns. Here, we present an overview of the key insights gained from the various numerical experiments and discuss the implications of the various factors influencing power system outcomes.

With help of Figure 4-1, all results are displayed across 9 metrics: System Average Cost; Power Capacity, Energy Storage Capacity; VRE Power Capacity; Gas Power Capacity; Annual VRE Curtailment; Unweighted Mean Price; Occurrence of Low Price Band and Extreme Price Band. Each metric shows the results of each Experiment Group (in colors) for the different CO_2 emission intensity (EI) constraints (NL, 50, 10, 5, 1 and 0 gCO_2/kWh). In addition, for each EI and metric, the magnitude found at the base case and the mean value across all experiments is highlighted with a black and a red line, respectively. Further, Figure 4-2 and Table 4.1 shows the results of the same metrics for the $5gCO_2/kWh$ emission intensity case, but breaking down the experiments to allow a clearer view of the spread of results by experiments. A complete set of similar figures along with the summary statistics tables for the data per EI and metric of interest is included in Appendix C.

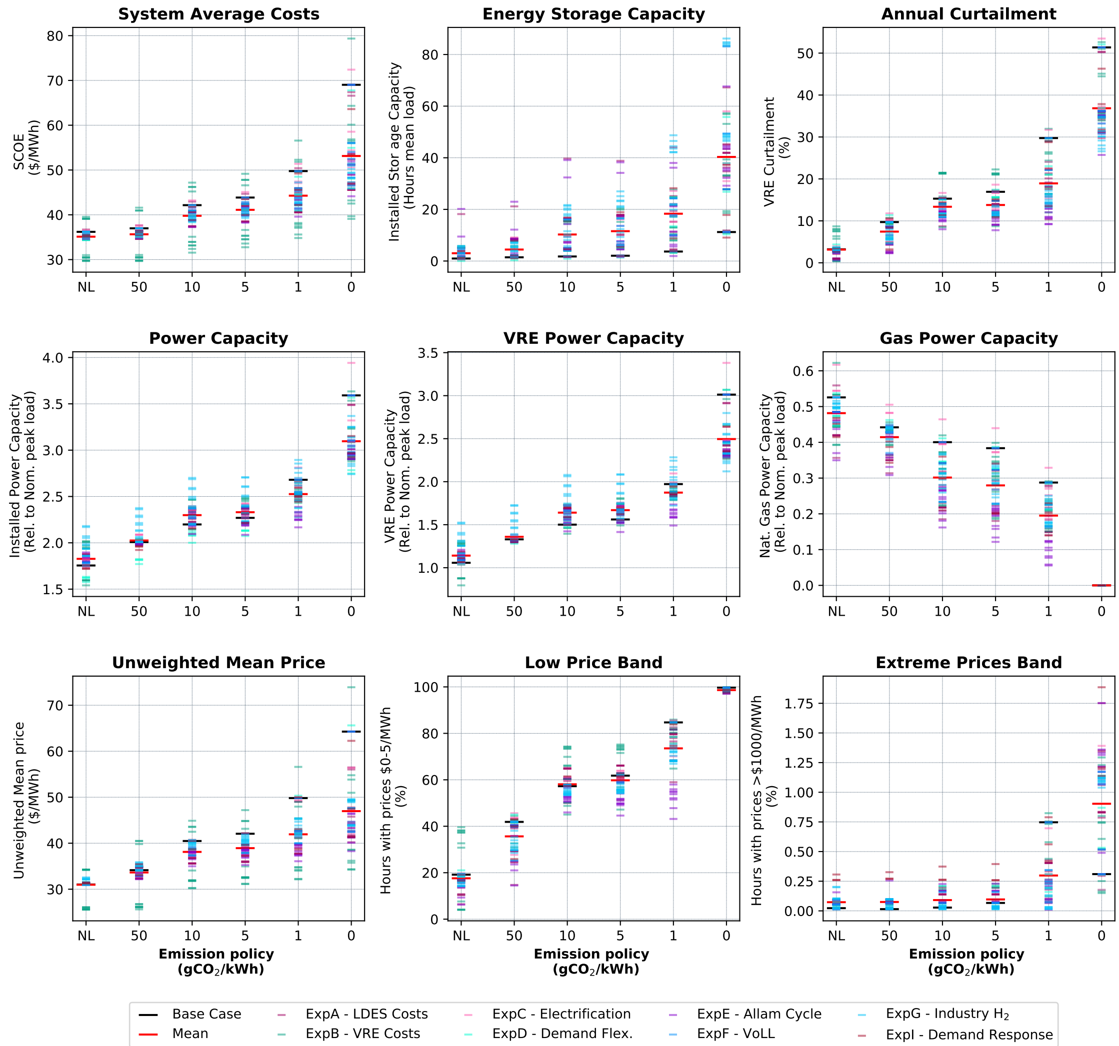

Figure 4-1: Results overview, showing the magnitude of the main metrics for all experiment groups and by emission policy.

Starting with the SCOE (top-left panel) and leaving aside the observation that it increases as the EI approaches zero, it becomes clear that: (1) the value of SCOE is most sensitive to the cost of VRE resources (experiment B, in dark-green) and (2) the spread of SCOE values for a given EI increases as the EI is more stringent. By observing SCOE results in Figure 4-2, all experiments except group B (sensitivities of VRE costs) exhibit a resulting SCOE between $38 and $45/MWh. In experiment group B, the lowest value is $33/MWh corresponding to low VRE cost and the highest SCOE is $49/MWh corresponding to the high VRE costs. Moreover, the reduction of SCOE by introducing other decarbonization factors such as LDES, Allam Cycle, DR or DF are exceeded by the reduction in SCOE with the low-cost projections of VRE. Therefore, the average system cost projection for a given EI, depends the most on the cost projections of VRE. It is worth noting that for all experiment groups, systems with Li-ion as the single technology, exhibit the highest SCOE Value.

Following low VRE costs, other factors with the greatest potential to reduce SCOE are: availability of Low cost LDES; coupling with the industry to supply Hydrogen; demand flexibility, demand response, and availability of the Allam cycle.

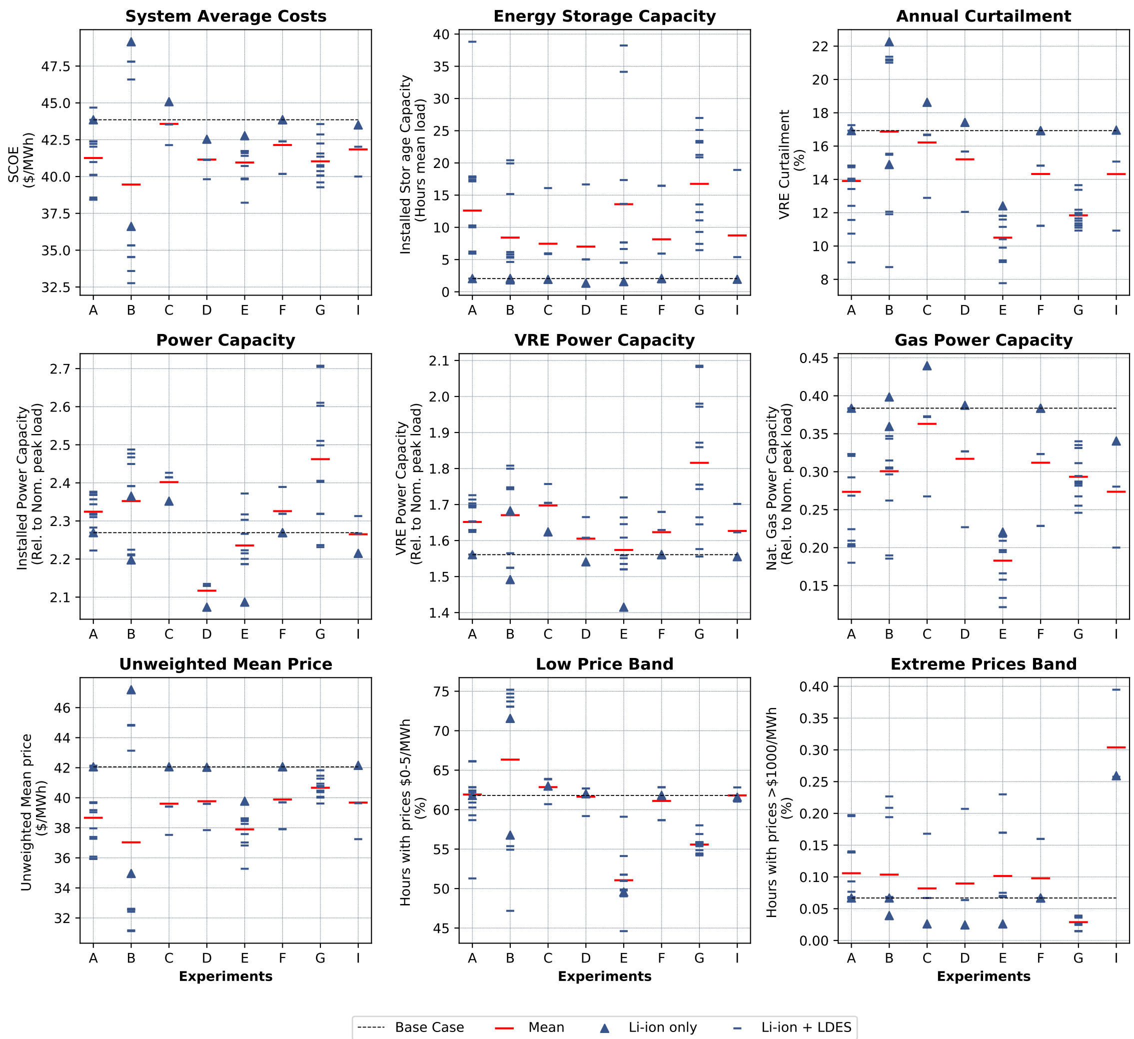

Figure 4-2: Results overview of the 5gCO_2/kWh case overview showing the magnitude of the main metrics by experiment group. By each experiment group, there is highlighted the scenario that contains Li-ion as the single storage technology.

	mean	std	min	25%	50%	75%	max	CoV
System Average Costs ($/MWh)	41.1	3.2	32.8	39.9	41.4	42.5	49.2	0.1
Power Capacity (Rel. to Nom. peak load)	2.3	0.1	2.1	2.2	2.3	2.4	2.7	0.1
Energy Storage Capacity (Hours mean load)	11.6	9.0	1.3	5.3	7.6	17.4	38.8	0.8
VRE Power Capacity (Rel. to Nom. peak load)	1.7	0.1	1.4	1.6	1.7	1.7	2.1	0.1
Gas Power Capacity (Rel. to Nom. peak load)	0.3	0.1	0.1	0.2	0.3	0.3	0.4	0.3
Annual Curtailment (%)	13.8	3.3	7.8	11.4	13.4	15.7	22.3	0.2
Price Volatility (-)	8.8	2.7	3.7	7.4	7.7	9.8	14.8	0.3
Unweighted Mean Price ($/MWh)	38.9	3.2	31.1	37.4	39.6	40.8	47.2	0.1
Extreme Prices Band (%)	0.1	0.1	0.0	0.1	0.1	0.1	0.4	0.8
Low Price Band (%)	59.8	6.9	44.6	55.4	60.3	62.8	75.2	0.1

Table 4.1: Summary statistics for overall results, taking into account all experiment results for the 5g case.

Next, on Power Capacity (central row in Figure 4-1 for all results and Figure 4-2 for the 5g results), it can be noted that the general trend is to increase total power capacity, along with VRE capacity as the EI goes to zero, while gas power capacity decreases. Total power capacity reaches up to 3.9 times the peak load in the 0g case and experiment C (reference electrification) and can be as low as 1.8 times in the No Limits Case. In the 5g case, total installed power capacity averages 2.2 times the peak load of the system. Consistently, the lowest values of installed power Capacity are reached with Experiment Group D (demand flexibility substitutes for storage power capacity) and the highest, with experiment group G (serving H_2 to the industry requires a higher deployment of generation capacity).

Except for the NL case, Li-ion only systems show the lowest installed power capacity, lowest VRE installed capacity and highest gas power capacity. This evidences the substitution effect of LDES for gas generation to allow a higher deployment of VRE, providing cheap energy to be stored in facilities that are lower in energy storage CAPEX (recall Table 2-6 and Figure 2-6), and in turn, reducing the overall system costs. On gas power capacity, the lowest values (higher substitution) are achieved with the availability of cheap storage technologies (Experiment group A).

Energy storage capacity also increases as the carbon emission intensity approaches zero, reaching values of 80+ hours of mean load of storage in the 0g case. At 5g, energy storage capacity has an average value of 11 hours of mean and ranges from 1.3 hours (Demand Flex case - Li-ion only), to 39 hours (Low LDES costs, with Metal-air at low cost). Across all EI cases, Li-ion only systems show the lowest installed energy storage capacity, being the lowest, in the case of experiment group D when demand flexibility is enabled.

Annual VRE curtailments (%), shown in the upper-right panel of Figure 4-1, also increase as the EI tightens, reaching over 50% in the 0g case. Overall, VRE curtailments are reduced when LDES is present, when demand management (DR-DF) is enabled, and when industrial demand for hydrogen is used.

The lower row of figures 4-1 and 4-2 shows the Unweighted Mean Price (simple mean of the time-series of marginal value of generation), the occurrence of prices in the Low Price Band (% of hours when prices are between \$0 and \$5/MWh) and Extreme prices band (% of hours when prices are above \$1,000/MWh). As can be noted, the three metrics increase as the emission constraint approaches to zero, and that the extreme prices band tends to climb starting at the 1gCO_2/kWh constraint. On the unweighted Mean price, the lower values are reached when low-cost VRE resources are available, since there is a greater number of zero priced hours in this case (increased share of low price band if low-cost VRE resources are available). Moreover, mean prices decrease with the introduction of LDES across all experiment groups and EIs (see appendix C for the results at all EIs).

The Low Band price metric is highest when there is low-cost VRE available (constraints NL, 10 and 5) and, in general, also for the configurations of Li-ion only systems. On the 1 and 0 gCO_2/kWh cases, this band can reach up to over 85 and 99.5% of all hours, respectively. Low price instances are decreased with increasing H_2 demand from the industry, with the presence of the Allam cycle, and under high VRE costs.

A similar effect can be seen in the Extreme Prices band metric, where industrial demand for H_2 can play an important stabilizer role. Indeed, it is the factor that has the greatest impact on reducing instances of extreme prices.

4.2 Effects Analysis

With the previous section, a general overview was provided to develop the intuition of the effects that each experiment group has on the metrics of interests. Here, the relative impact of the factors is quantified by analyzing the change in the metrics of interest when a level of a factor is changed independently of everything else.

Three clusters of factors are considered:

1. Adding technologies: RFB; RFB + H2; RFB + Metal-air; and Allam Cycle

2. Impact of cost sensitivities: lower cost of storage; increased cost of storage; lower cost of VRE generation and increase cost of VRE generation. Cost sensitivities do not add technologies, and the effect is computed as the change from a central case to the cost sensitivity (medium cost). For example, changing the cost of RFB from medium to low.

3. Enabling demand-side factors: Industrial demand for hydrogen; demand flexibility; and demand response.

The effect of what is added/changed/enabled for each of these clusters of factors, is quantified in isolation. Therefore, pairs of experiments were selected from Table 2.9 to do the computations.

For example, there are three pairs of experiment IDs that help to study the effect of adding RFB at medium cost level: pair (16,17) serves to determine the effect of RFB if VRE is at the low-cost projection; pair (1,2) is for the effect of RFB at VRE at medium cost; and pair (23,24) for VRE at high-cost projection. This way, the effect of a single factor is isolated and can be quantified properly.

The pairs of experiments with their respective IDs are listed in tables 4.2, 4.3 and 4.4. For each of the pairs, the effect of changing the level of the factor was computed for every emission intensity limit and averaged by factor.

The effects' analysis allow the quantification of each decarbonization factor, and the results for the emission intenstiy of $5gCO_2/kWh$ are shown in Figure 4-3, with the

Factor	Description	Initial Technology Mix					Initial ID	End ID
		VRE	Li-ion	RFB	H2	Ma		
RFB (M)	Adding RFB (M)	L	M	-	-	-	16	17
RFB (M)	Adding RFB (M)	M	M	-	-	-	1	2
RFB (M)	Adding RFB (M)	H	M	-	-	-	23	24
H2 (M)	Adding Hydrogen (M)	L	M	M	-	-	17	18
H2 (M)	Adding Hydrogen (M)	M	M	M	-	-	2	3
H2 (M)	Adding Hydrogen (M)	H	M	M	-	-	24	25
Metal-air (M)	Adding Metal-air (M)	L	M	M	-	-	17	19
Metal-air (M)	Adding Metal-air (M)	M	M	M	-	-	2	4
Metal-air (M)	Adding Metal-air (M)	H	M	M	-	-	24	26
Allam	Adding Allam Cycle (M)	M	M	-	-	-	1	35
Allam	Adding Allam Cycle (M)	M	M	M	L		10	36
Allam	Adding Allam Cycle (M)	M	M	M	M		3	37
Allam	Adding Allam Cycle (M)	M	M	M	H		11	38
Allam	Adding Allam Cycle (M)	M	M	M	-	L	13	39
Allam	Adding Allam Cycle (M)	M	M	M	-	M	4	40
Allam	Adding Allam Cycle (M)	M	M	M	-	H	14	41

Table 4.2: Technology addition cluster: Pairs of experiments (Initial and End IDs) to compute the effect of the factors. Initial ID is the experiment used as reference, before the change in the description column is applied.

mean values listed in Table 4.5. the complete set of results for all emission policies is included in Appendix D.

Highlights of the 5gCO_2/kWh results is that cost VRE is the most impactful factor on SCOE, with a potential decrease on average of 17% and, on the high end, of +12%. It is followed by the hydrogen in the industry, and addition of LDES. The effect of low-cost storage is on top of the reduction caused by the addition of LDES at medium cost. This means, that on top of the average 3-3.6% SCOE reduction by the addition of LDES (RFB or Metal-air), an additional 4% reduction can be achieved if the low-cost scenario is met by 2050. Hydrogen storage at 5g is usually not built, and therefore its effect is small.

In spite of being the most relevant factor to achieve a low-cost power system, widespread penetration of VRE have the drawback of increasing the low-band of the prices' distribution. Having a high % of hours at the low-price band creates a potential profitability problem for technologies, as they will rely on fewer hours of higher prices to recover investments in energy-only market configurations. On the other hand, the introduction of the Allam cycle and the industrial demand for hydrogen have the

Factor	Description	Initial Technology Mix					Initial ID	End ID
		VRE	Li-ion	RFB	H2	Ma		
Li-ion-low	Li-ion to low cost	L	M	M			17	20
Li-ion-low	Li-ion to low cost	L	M	M	M		18	21
Li-ion-low	Li-ion to low cost	L	M	M		M	19	22
LDES-low	Li-ion and RFB to low cost	M	M	M			2	6
LDES-low	RFB to low cost	M	M	M			2	8
LDES-low	H2 to low cost	M	M	M	M		3	10
LDES-low	Metal-air to low cost	M	M	M		M	4	13
LDES-high	Li-ion and RFB to high cost	M	M	M			2	7
LDES-high	RFB to high cost	M	M	M			2	9
LDES-high	H2 to high cost	M	M	M	M		3	11
LDES-high	Metal-air to high cost	M	M	M		M	4	14
VRE-low	VRE to low cost	M	M				1	16
VRE-low	VRE to low cost	M	M	M			2	17
VRE-low	VRE to low cost	M	M	M	M		3	18
VRE-low	VRE to low cost	M	M	M		M	4	19
VRE-high	VRE to high cost	M	M				1	23
VRE-high	VRE to high cost	M	M	M			2	24
VRE-high	VRE to high cost	M	M	M	M		3	25
VRE-high	VRE to high cost	M	M	M		M	4	26

Table 4.3: Cost-sensitivity cluster: pairs of experiments (Initial and End IDs) to compute the effect of the factors. Initial ID is the experiment used as reference, before the change in the description column is applied.

opposite effect: while mildly reducing the SCOE, they are the two key factors that decrease the low price band of prices, and also the amount of hours with extreme prices. This suggests, that these factors complement each other in a synergistic way.

Demand Flexibility is the factor that has the greatest potential to displace power capacity (mainly short-term storage), and is also helpful to reduce the amount of hours with extreme prices. Metal-air, has a great influence on the amount of curtailments (-25%) and also the displacement of gas capacity (32%). It contributes, nonetheless, to the increase in hours of extreme prices.Demand response brings the greatest reduction to prices volatility, which is seen in Table 4.5,

It is important to note that the impact of the factors depend on the emission constraint and therefore, depending on the decarbonization level, some factors become more relevant than others. For example, while demand flexibility decreases its value towards zero emissions, whereas, the addition of RFB, hydrogen for the industry and Metal Air becomes impactful. Indeed, at 0g, RFB has the greatest impact of all factors. (see Table 4.6)

Factor	Description	Initial Technology Mix					Initial ID	End ID
		VRE	Li-ion	RFB	H2	Ma		
H2_ind	Enable Industry H2 (100%)	M	M		Tank		2	55
H2_ind	Enable Industry H2 (100%)	M	M		Geo		2	60
DemFlex	Enable Demand Flex	M	M				1	31
DemFlex	Enable Demand Flex	M	M	M			2	32
DemFlex	Enable Demand Flex	M	M	M	M		3	33
DemFlex	Enable Demand Flex	M	M	M		M	4	34
DemResp	Enable Demand Response	M	M				1	61
DemResp	Enable Demand Response	M	M	M			2	62
DemResp	Enable Demand Response	M	M	M			5	63

Table 4.4: Demand-side cluster: pairs of experiments (Initial and End IDs) to compute the effect of each factor. Initial ID is the experiment used as reference, before the change in the description column is applied.

	SCOE	GenCapPeak	StorCapHours	VRE_Cap	Gas_Cap	Curtailment	CoV	MeanPrice	ExtrPriceBand	ZeroPriceBand
RFB (M)	-3.2	1.3	179.0	3.4	-14.6	-12.1	-15.3	-5.8	25.0	1.4
H2 (M)	-0.0	-0.1	9.9	0.0	-1.6	-0.9	0.1	-0.1	0.0	-0.7
Metal-air (M)	-3.6	1.4	218.3	3.4	-31.5	-25.4	3.9	-4.2	212.2	-7.8
Allam	-1.3	-4.7	-22.3	-6.1	-31.0	-18.4	7.9	-2.3	-11.6	-16.5
LI-ion-low	-2.3	2.8	-7.2	0.0	2.6	0.3	-5.7	-0.3	-3.9	-0.9
LDES-low	-1.9	0.5	94.0	1.3	-11.7	-9.1	3.9	-1.9	-12.2	-4.3
LDES-high	1.5	-0.9	-27.6	-1.6	9.8	5.5	9.4	2.2	-13.1	-0.5
VRE-low	-17.0	3.8	2.0	7.2	-9.1	37.9	28.5	-17.6	-7.5	19.6
VRE-high	12.8	-4.4	-9.1	-6.2	8.8	-18.6	-16.0	13.0	4.0	-13.1
H2_ind	-5.7	12.4	199.6	21.3	-15.0	-23.2	97.2	1.7	-61.0	-11.5
DemFlex	-2.9	-8.4	-18.1	-1.4	1.3	4.8	1.8	-0.2	-16.8	0.1
DemResp	-0.7	-2.2	-2.9	-0.3	-9.6	1.2	-49.9	0.0	224.4	-0.1

Table 4.5: Results of the effects' analysis at 5gCO_2/kWh emission intensity, showing the average impact (change in %) of each factor on the key metrics.

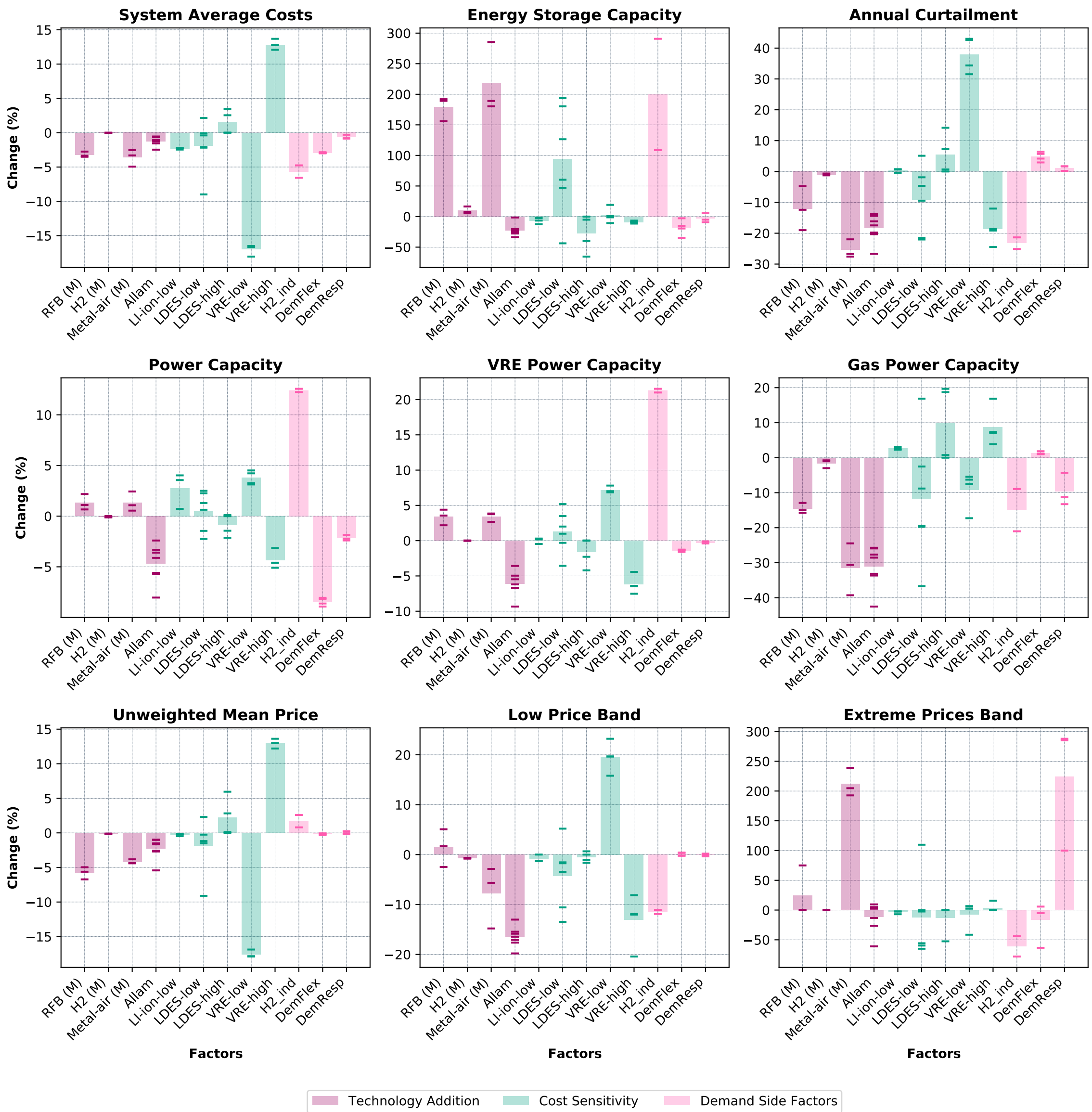

Figure 4-3: Results of the effects' analysis at $5gCO_2/kWh$ emission intensity, showing the impact (change in %) of each factor on the key metrics. Bars describe the magnitude of the average change, while the small horizontal lines is the result of a single pair of experiments.

	NL	50	10	5	1	0
RFB (M)	-1.4	-1.6	-2.7	-3.2	-7.3	-18.3
H2 (M)	0.0	0.0	-0.0	-0.0	-0.8	-6.9
Metal-air (M)	-0.2	-0.7	-3.3	-3.6	-5.9	-13.2
Allam	-0.0	-0.0	-0.7	-1.3	-4.0	0.1
LI-ion-low	-2.4	-2.4	-2.4	-2.3	-2.1	-1.6
LDES-low	-0.8	-1.1	-1.8	-1.9	-3.6	-4.7
LDES-high	0.4	0.7	1.4	1.5	3.0	7.2
VRE-low	-14.4	-15.9	-17.4	-17.0	-17.4	-17.8
VRE-high	9.7	12.5	12.9	12.8	13.9	15.2
H2_ind	-1.5	-2.3	-4.9	-5.7	-8.0	-13.7
DemFlex	-3.8	-3.6	-3.0	-2.9	-2.6	-1.8
DemResp	-1.3	-1.1	-0.7	-0.7	-0.9	-4.3

Table 4.6: Impact of the decarbonization factors on SCOE for the different emission constraints. Values show the % change in SCOE for each factor and emission intensity

4.3 Conclusion

Over the course of this work, several factors that contribute to the deep decarbonization of power systems were analyzed from the perspective of their influence on the following key aspects: System average cost of electricity (SCOE); generation assets; energy storage assets; wholesale electricity prices distributions; and system operation.

The conclusions of this work are the following.

1. Complementarity: The analysis allowed to conclude that each of the factors impact the power system in specific and different ways that are complementary with each other and depend on the degree of system decarbonization. It is desirable to combine them to achieve the deep decarbonization of the power system, with low cost, high reliability, reasonable wholesale prices distributions, low VRE curtailments and low amount of assets deployed (system footprint).

2. Cost-based decarbonization: even under no carbon intensity emission policy, the system tends to decarbonize itself, driven by the good VRE resources in Texas and the projected cost of technologies in 2050. At the base case, the system showed a 72% of decarbonization with respect to the 2018 CO_2 emission level.

3. Cost to decarbonize: Although, SCOE grows exponentially as the system decarbonizes and approaches to zero emissions, achieving a decarbonization of 98.4% (with an intensity of 5gCO_2/kWh), implies an average SCOE of \$41/MWh, which is only a 17% increment from the No Limits policy case.

4. Decreasing SCOE: For a given emission intensity constraint, the average system cost can be reduced significantly, with the cost of VRE generation being the most impactful factor. Its impact on SCOE reduction stays between 14% and 18% across emission intensities (table 4.6). Electrolytic hydrogen for the industry follows as the second most influential factor to reduce cost (the only exception being at 0g, where the addition of RFB is the most impactful), with an impact that ranges between a 14% cost reduction at 0g and 1.5% at the no

limits scenario. Next, is the addition of LDES which becomes more relevant as the emission intensity approaches zero. Low-cost LDES is the third most relevant factor for SCOE reduction.

5. Prices distributions: The share of zero prices increase as the system decarbonizes and prices of VRE generation declines, posing a challenge on technologies as they start to rely on a small amount of hours to recover investments in energy-only market configurations investigated here (about 80% of hours are in the zero band at the 1gCO_2/kWh case). Depending on the emission intensity, results show that the Allam cycle, along with the coupling of the power system with the industry to supply hydrogen for heat demand, and LDES help significantly to reduce the amount of hours with zero prices and also the hours with extreme prices with. Allam Cycle shows also a positive effect to reduce system footprint, by displacing both VRE and Gas power capacity.

6. Demand-side factors: under deep decarbonization assumptions, demand flexibility and demand response are found to be not as impactful as other factors in reducing system costs (this is the opposite at the No Limits case). At low emission constraints, their role is primarily to reduce system footprint and to decrease price volatility.

7. Electrification in Texas: This case study analyzed the high and the reference electrification scenarios developed by NREL [1] for Texas, and found that high electrification has a positive effect in terms of achieving lower system costs, lower specific footprint (capacity as % of peak load) and lower VRE curtailments. This is mainly because the increased load due to electrification is in-sync with the VRE potential in Texas, that allows better resource utilization. It must be noted that demand flexibility could have a greater potential if this alignment in profiles was not the case.

4.4 Future Work

As seen over the course of this work, one of the main mechanisms to decarbonize systems is to displace gas generation by increasing VRE power capacity, and balance the system with storage technologies, low CO_2 dispatchable technologies (Allam Cycle) and demand-side factors such as coupling the power system with the industry, demand flexibility and demand response. The common key element to achieve low emissions is to offset the increase in capital cost of VRE and storage by decreasing the variable operational cost of gas generation. Therefore, it is important to study sensitivities around natural gas price, as lower levels will make the road to decarbonization more expensive.

A second area of interest, is to implement a post-optimization framework to account for the issue that in real-life power system operators do not have perfect foresight on VRE resource availability. One idea is to perform the system optimization as was done here, but simulate operations afterwards under weather uncertainty, making operational decisions each hour based on probabilistic forecast for a chosen time window. With this type of framework, a better understanding of the value of technologies can be gained, and the actual system reliability can be assessed.

Third, multi-objective optimization can be implemented to account not only for minimum system cost, but also for reducing the magnitude of extreme price bands and system footprint. Judgement will be needed to weight these variables in the objective function.

Finally, a multi-zone model for Texas can be developed to account for the balancing zones in ERCOT and study the system evolution in a more realistic way.

Appendix A

appendixA

	Tech	Sensitivity	Overnight Discharging Power Cost ($/MW)	Overnight Charging Power Cost ($/MW)	Overnight Energy Cost ($/MWh)	Capital Recovery Period Discharge (yrs)	Capital Recovery Period Charge (yrs)	Capital Recovery Period Storage (yrs)	After Tax WACC (%)	Annualized Discharging Investment ($/MW-year)	Annualized Charging Investment ($/MW-year)	Annualized Investment ($/MWh-year)	FOM Discharge ($/MW-year)	FOM Charge ($/MW-year)	FOM ($/MWh-year)	Efficiency Up (%)	Efficiency Down (%)	Self-Discharge (Fraction per hour)
Li-ion Estimates	Today	2020	260,021	-	298,647	20	-	20	4.5%	20,000	-	23,000	1,400	-	6,820	92.0%	92.0%	0.20%
Li-ion Estimates	Low	2050	31,738	-	70,910	20	-	20	4.5%	2,400	-	5,500	250	-	1,420	92.0%	92.0%	0.20%
Li-ion Estimates	Mid	2050	109,564	-	125,840	20	-	20	4.5%	8,400	-	9,700	750	-	2,230	92.0%	92.0%	0.20%
Li-ion Estimates	High	2050	154,088	-	176,978	20	-	20	4.5%	11,800	-	13,600	1,400	-	3,160	92.0%	92.0%	0.20%
RFB Estimates	Today	2020	-	-	171,040	20	-	20	4.5%	-	-	13,100	4,080	-	-	91.7%	87.5%	0.00%
RFB Estimates	Low	2050	296,680	-	15,460	20	-	20	4.5%	22,800	-	1,200	4,080	-	-	91.7%	87.5%	0.00%
RFB Estimates	Mid	2050	395,710	-	47,970	20	-	20	4.5%	30,400	-	3,700	4,080	-	-	91.7%	87.5%	0.00%
RFB Estimates	High	2050	529,920	-	102,160	20	-	20	4.5%	40,700	-	7,900	4,080	-	-	91.7%	87.5%	0.00%
Metal-air Estimates	Today	2020	-	-	3,700	20	-	20	4.5%	-	-	280	-	-	90	72.0%	60.1%	1.00%
Metal-air Estimates	Low	2050	595,210	-	130	20	-	20	4.5%	45,800	-	10	14,880	-	3	70.2%	58.9%	0.20%
Metal-air Estimates	Mid	2050	642,770	-	2,410	20	-	20	4.5%	49,400	-	190	16,070	-	60	72.7%	63.0%	0.20%
Metal-air Estimates	High	2050	949,560	-	3,630	20	-	20	4.5%	73,000	-	280	23,740	-	90	72.0%	60.1%	0.20%
Hydrogen Estimates	Today	2020	1,363,200	1,770,714	8,000	20	30	30	4.5%	104,800	108,700	490	11,000	75,200	80	58.0%	44.7%	-
Hydrogen Estimates	Ultra-Low	2050	1,189,884	479,286	1,144	20	30	30	4.5%	91,500	29,400	70	11,000	20,355	26	77.0%	65.0%	-
Hydrogen Estimates	Low	2050	1,149,888	356,143	6,000	20	30	30	4.5%	88,400	21,900	370	11,000	15,125	60	80.0%	70.0%	-
Hydrogen Estimates	Mid	2050	1,189,884	479,286	7,000	20	30	30	4.5%	91,500	29,400	430	11,000	20,355	70	77.0%	65.0%	-
Hydrogen Estimates	High	2050	1,229,880	602,429	8,000	20	30	30	4.5%	94,500	37,000	490	11,000	25,584	80	60.0%	60.0%	-
Thermal Estimates	Today	2020	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Thermal Estimates	Low	2050	494,000	3,340	2,900	30	30	30	4.5%	30,300	210	180	3,930	80	16	99.5%	55.0%	0.02%
Thermal Estimates	Mid	2050	736,000	3,340	5,400	30	30	30	4.5%	45,200	210	330	3,930	80	30	99.5%	50.0%	0.02%
Thermal Estimates	High	2050	1,226,000	3,340	9,000	30	30	30	4.5%	75,300	210	550	3,930	80	51	99.5%	46.0%	0.04%

Table A.1: Parameters that model storage technologies and cost sensitivities explored. Parameters and costs projections from [12]

Technology	Sensitivity	Overnight Investment Cost ($/MW)	DC-AC Ratio	Overnight Investment Cost ($/MW)	Capital Recovery Period (yrs)	After Tax WACC (%)	Annualized Investment ($/MW-year)	FOM ($/MW-year)	VOM ($/MWh)
Utility-Scale PV	Low	560,129	1.00	560,129	30	6.1%	34,400	6,560	-
Utility-Scale PV	Mid	724,940	1.00	724,940	30	6.1%	44,500	8,490	-
Utility-Scale PV	High	933,130	1.00	933,130	30	6.1%	57,300	10,928	-
Onshore Wind	Low	722,431	1.00	722,431	30	6.1%	44,400	26,645	0.01
Onshore Wind	Mid	1,084,798	1.00	1,084,798	30	6.1%	66,600	34,568	0.01
Onshore Wind	High	1,259,250	1.00	1,259,250	30	6.1%	77,300	41,590	0.01

Table A.2: Parameters that model storage technologies and cost sensitivities explored. Parameters and costs projections from [12]

Appendix B

Results Tables

B.1 Experiment Group A

B.1.1 Exp. A - Installed Power Capacity

ID	TM	EI	CCGT	OCGT	CCS	Wind	PV	Li	RFB	H2	Ma	Th	Total
1	TM0	0	0	0	0	191	264	87	0	0	0	0	543
1	TM0	1	12	2	30	143	155	64	0	0	0	0	405
1	TM0	5	16	13	29	115	121	49	0	0	0	0	343
1	TM0	10	25	14	21	112	115	45	0	0	0	0	332
1	TM0	50	49	17	0	98	103	36	0	0	0	0	303
1	TM0	NL	60	19	0	80	80	26	0	0	0	0	265
2	TM1	0	0	0	0	104	268	7	88	0	0	0	467
2	TM1	1	9	3	22	108	176	13	54	0	0	0	385
2	TM1	5	17	12	20	99	147	14	41	0	0	0	350
2	TM1	10	25	14	13	100	139	13	38	0	0	0	342
2	TM1	50	49	16	0	94	106	18	20	0	0	0	303
2	TM1	NL	57	16	0	75	90	12	20	0	0	0	270
3	TM2	0	0	0	0	121	233	4	65	24	0	0	447
3	TM2	1	8	3	20	108	171	9	47	11	0	0	378
3	TM2	5	17	12	19	99	147	14	41	1	0	0	350
3	TM2	10	25	14	13	100	139	13	38	0	0	0	342
3	TM2	50	49	16	0	94	106	18	20	0	0	0	303
3	TM2	NL	57	16	0	75	90	12	20	0	0	0	270

Table B.1 continued from previous page

ID	TM	EI	CCGT	OCGT	CCS	Wind	PV	Li	RFB	H2	Ma	Th	Total
4	TM3	0	0	0	0	127	229	0	59	0	33	0	448
4	TM3	1	7	0	17	111	167	13	35	0	25	0	376
4	TM3	5	23	0	11	108	148	16	28	0	20	0	354
4	TM3	10	31	0	4	108	145	17	27	0	20	0	352
4	TM3	50	48	7	0	90	107	20	16	0	11	0	299
4	TM3	NL	55	14	0	76	91	13	19	0	3	0	272
5	TM4	0	0	0	0	91	268	6	46	0	0	44	455
5	TM4	5	21	2	9	99	159	18	23	0	0	26	356
5	TM4	10	27	3	3	100	156	18	22	0	0	26	355
5	TM4	50	46	9	0	85	112	19	14	0	0	15	300
5	TM4	NL	54	13	0	74	97	14	15	0	0	9	276
6	TM5	0	0	0	0	94	255	13	86	0	0	0	448
6	TM5	1	9	0	14	92	188	17	63	0	0	0	383
6	TM5	5	16	5	9	93	163	19	52	0	0	0	358
6	TM5	10	23	7	3	94	161	17	51	0	0	0	356
6	TM5	50	41	12	0	79	122	16	34	0	0	0	304
6	TM5	NL	49	14	0	74	104	15	26	0	0	0	283
7	TM6	0	0	0	0	192	248	14	73	0	0	0	527
7	TM6	1	12	3	27	138	158	20	37	0	0	0	396
7	TM6	5	17	11	30	116	120	23	19	0	0	0	336
7	TM6	10	25	14	22	112	114	23	18	0	0	0	326
7	TM6	50	51	16	0	100	100	23	12	0	0	0	302
7	TM6	NL	64	21	0	79	77	14	8	0	0	0	262
8	TM7	0	0	0	0	90	253	0	96	0	0	0	439
8	TM7	1	8	0	14	87	194	0	78	0	0	0	381
8	TM7	5	17	6	9	87	172	0	69	0	0	0	359
8	TM7	10	23	7	3	90	167	0	66	0	0	0	356
8	TM7	50	41	12	0	74	129	0	48	0	0	0	306
8	TM7	NL	49	14	0	68	113	0	41	0	0	0	285
9	TM8	0	0	0	0	192	248	45	42	0	0	0	527
9	TM8	1	12	3	28	140	156	51	12	0	0	0	401
9	TM8	5	16	13	29	115	121	49	0	0	0	0	343
9	TM8	10	25	14	21	112	115	45	0	0	0	0	332
9	TM8	50	49	17	0	98	103	36	0	0	0	0	303

Table B.1 continued from previous page

ID	TM	EI	CCGT	OCGT	CCS	Wind	PV	Li	RFB	H2	Ma	Th	Total
9	TM8	NL	60	19	0	80	80	26	0	0	0	0	265
10	TM9	0	0	0	0	122	226	2	59	32	0	0	441
10	TM9	1	7	4	18	109	167	9	41	17	0	0	373
10	TM9	5	18	10	17	103	143	12	35	8	0	0	345
10	TM9	10	25	12	11	102	139	12	34	5	0	0	341
10	TM9	50	49	16	0	94	106	18	20	0	0	0	303
10	TM9	NL	57	16	0	75	90	12	20	0	0	0	270
11	TM10	0	0	0	0	129	226	9	62	22	0	0	447
11	TM10	1	8	4	21	109	174	12	52	3	0	0	383
11	TM10	5	17	12	20	99	147	14	41	0	0	0	350
11	TM10	10	25	14	13	100	139	13	38	0	0	0	342
11	TM10	50	49	16	0	94	106	18	20	0	0	0	303
11	TM10	NL	57	16	0	75	90	12	20	0	0	0	270
12	TM11	0	0	0	0	94	255	13	86	0	0	0	448
12	TM11	1	9	0	14	92	188	17	63	0	0	0	383
12	TM11	5	16	5	9	93	163	19	52	0	0	0	358
12	TM11	10	23	7	3	94	161	17	51	0	0	0	356
12	TM11	50	41	12	0	79	122	16	34	0	0	0	304
12	TM11	NL	49	14	0	74	104	15	26	0	0	0	283
13	TM12	0	0	0	0	144	203	9	38	0	44	0	439
13	TM12	1	4	0	17	112	163	15	33	0	28	0	373
13	TM12	5	20	0	8	113	148	18	27	0	25	0	359
13	TM12	10	28	0	0	114	145	18	26	0	26	0	357
13	TM12	50	47	0	0	89	107	20	16	0	19	0	298
13	TM12	NL	54	0	0	78	97	15	18	0	17	0	279
14	TM13	0	0	0	0	121	245	0	66	0	28	0	459
14	TM13	1	9	0	19	110	170	10	41	0	19	0	377
14	TM13	5	19	6	15	104	145	13	33	0	12	0	349
14	TM13	10	28	6	8	105	142	14	31	0	12	0	346
14	TM13	50	49	15	0	94	106	18	19	0	1	0	303
14	TM13	NL	57	16	0	75	90	12	20	0	0	0	270
15	TM14	0	0	0	0	94	255	13	86	0	0	0	448
15	TM14	1	9	0	14	92	188	17	63	0	0	0	383
15	TM14	5	16	5	9	93	163	19	52	0	0	0	358

Table B.1 continued from previous page

ID	TM	EI	CCGT	OCGT	CCS	Wind	PV	Li	RFB	H2	Ma	Th	Total
15	TM14	10	23	7	3	94	161	17	51	0	0	0	356
15	TM14	50	41	12	0	79	122	16	34	0	0	0	304
15	TM14	NL	49	14	0	74	104	15	26	0	0	0	283

Table B.1: Experiment A: Installed power capacity (GW)

B.1.2 Exp. A - Energy Storage Capacity

ID	TM	EI	Li-ion	RFB	Hydrogen	Metal-air	Thermal	Total
1	TM0	0	916.1	0.0	0.0	0.0	0.0	916.1
1	TM0	1	299.9	0.0	0.0	0.0	0.0	299.9
1	TM0	5	167.3	0.0	0.0	0.0	0.0	167.3
1	TM0	10	143.6	0.0	0.0	0.0	0.0	143.6
1	TM0	50	117.5	0.0	0.0	0.0	0.0	117.5
1	TM0	NL	79.2	0.0	0.0	0.0	0.0	79.2
2	TM1	0	7.1	2261.4	0.0	0.0	0.0	2268.5
2	TM1	1	18.2	800.4	0.0	0.0	0.0	818.6
2	TM1	5	20.2	463.8	0.0	0.0	0.0	483.9
2	TM1	10	19.3	390.7	0.0	0.0	0.0	410.0
2	TM1	50	26.5	135.6	0.0	0.0	0.0	162.2
2	TM1	NL	19.2	118.6	0.0	0.0	0.0	137.8
3	TM2	0	3.7	778.7	2052.3	0.0	0.0	2834.6
3	TM2	1	11.5	508.9	725.0	0.0	0.0	1245.4
3	TM2	5	19.8	452.4	37.8	0.0	0.0	509.9
3	TM2	10	19.3	390.7	0.0	0.0	0.0	410.0
3	TM2	50	26.5	135.6	0.0	0.0	0.0	162.2
3	TM2	NL	19.2	118.6	0.0	0.0	0.0	137.8
4	TM3	0	0.0	477.9	0.0	3212.0	0.0	3689.9
4	TM3	1	18.1	261.6	0.0	1773.2	0.0	2052.9
4	TM3	5	23.3	202.0	0.0	1173.7	0.0	1399.0
4	TM3	10	24.8	188.9	0.0	1137.5	0.0	1351.2
4	TM3	50	31.9	105.2	0.0	553.9	0.0	690.9
4	TM3	NL	20.8	115.8	0.0	103.5	0.0	240.1
5	TM4	0	6.5	382.0	0.0	0.0	3155.7	3544.2

Table B.2 continued from previous page

ID	TM	EI	Li-ion	RFB	Hydrogen	Metal-air	Thermal	Total
5	TM4	5	27.9	158.7	0.0	0.0	1275.4	1462.0
5	TM4	10	27.8	142.2	0.0	0.0	1174.9	1345.0
5	TM4	50	29.8	84.3	0.0	0.0	543.9	658.1
5	TM4	NL	21.8	81.4	0.0	0.0	220.5	323.6
6	TM5	0	13.6	3407.8	0.0	0.0	0.0	3421.4
6	TM5	1	26.1	1734.1	0.0	0.0	0.0	1760.1
6	TM5	5	29.8	1420.7	0.0	0.0	0.0	1450.4
6	TM5	10	26.6	1245.5	0.0	0.0	0.0	1272.1
6	TM5	50	24.0	685.7	0.0	0.0	0.0	709.7
6	TM5	NL	22.7	396.4	0.0	0.0	0.0	419.1
7	TM6	0	17.4	942.1	0.0	0.0	0.0	959.5
7	TM6	1	34.1	335.9	0.0	0.0	0.0	370.0
7	TM6	5	40.7	125.0	0.0	0.0	0.0	165.7
7	TM6	10	39.3	112.0	0.0	0.0	0.0	151.3
7	TM6	50	36.9	74.9	0.0	0.0	0.0	111.9
7	TM6	NL	25.8	37.0	0.0	0.0	0.0	62.8
8	TM7	0	0.0	3677.5	0.0	0.0	0.0	3677.5
8	TM7	1	0.0	1801.6	0.0	0.0	0.0	1801.6
8	TM7	5	0.0	1421.0	0.0	0.0	0.0	1421.0
8	TM7	10	0.0	1250.1	0.0	0.0	0.0	1250.1
8	TM7	50	0.4	629.8	0.0	0.0	0.0	630.1
8	TM7	NL	0.4	411.6	0.0	0.0	0.0	412.0
9	TM8	0	219.4	741.2	0.0	0.0	0.0	960.6
9	TM8	1	180.7	173.4	0.0	0.0	0.0	354.1
9	TM8	5	167.3	0.0	0.0	0.0	0.0	167.3
9	TM8	10	143.6	0.0	0.0	0.0	0.0	143.6
9	TM8	50	117.5	0.0	0.0	0.0	0.0	117.5
9	TM8	NL	79.2	0.0	0.0	0.0	0.0	79.2
10	TM9	0	2.0	512.0	2550.9	0.0	0.0	3065.0
10	TM9	1	11.8	365.2	1204.2	0.0	0.0	1581.2
10	TM9	5	17.0	319.7	480.5	0.0	0.0	817.3
10	TM9	10	17.3	308.3	284.6	0.0	0.0	610.1
10	TM9	50	26.5	135.6	0.0	0.0	0.0	162.2

Table B.2 continued from previous page

ID	TM	EI	Li-ion	RFB	Hydrogen	Metal-air	Thermal	Total
10	TM9	NL	19.2	118.6	0.0	0.0	0.0	137.8
11	TM10	0	11.2	851.9	1813.9	0.0	0.0	2677.0
11	TM10	1	16.5	718.6	187.8	0.0	0.0	923.0
11	TM10	5	20.2	463.8	0.0	0.0	0.0	483.9
11	TM10	10	19.3	390.7	0.0	0.0	0.0	410.0
11	TM10	50	26.5	135.6	0.0	0.0	0.0	162.2
11	TM10	NL	19.2	118.6	0.0	0.0	0.0	137.8
12	TM11	0	13.6	3407.8	0.0	0.0	0.0	3421.4
12	TM11	1	26.1	1734.1	0.0	0.0	0.0	1760.1
12	TM11	5	29.8	1420.7	0.0	0.0	0.0	1450.4
12	TM11	10	26.6	1245.5	0.0	0.0	0.0	1272.1
12	TM11	50	24.0	685.7	0.0	0.0	0.0	709.7
12	TM11	NL	22.7	396.4	0.0	0.0	0.0	419.1
13	TM12	0	10.7	292.1	0.0	5185.3	0.0	5488.1
13	TM12	1	20.4	248.1	0.0	3325.1	0.0	3593.6
13	TM12	5	26.3	195.9	0.0	2946.1	0.0	3168.2
13	TM12	10	26.2	180.7	0.0	3032.4	0.0	3239.3
13	TM12	50	31.6	105.5	0.0	1590.7	0.0	1727.7
13	TM12	NL	24.0	113.6	0.0	1346.7	0.0	1484.3
14	TM13	0	0.0	568.8	0.0	2388.9	0.0	2957.7
14	TM13	1	11.2	336.1	0.0	1069.2	0.0	1416.5
14	TM13	5	17.2	276.3	0.0	547.0	0.0	840.5
14	TM13	10	17.8	251.2	0.0	507.6	0.0	776.6
14	TM13	50	27.7	128.0	0.0	41.4	0.0	197.0
14	TM13	NL	19.2	118.6	0.0	0.0	0.0	137.8
15	TM14	0	13.6	3407.8	0.0	0.0	0.0	3421.4
15	TM14	1	26.1	1734.1	0.0	0.0	0.0	1760.1
15	TM14	5	29.8	1420.7	0.0	0.0	0.0	1450.4
15	TM14	10	26.6	1245.5	0.0	0.0	0.0	1272.1
15	TM14	50	24.0	685.7	0.0	0.0	0.0	709.7
15	TM14	NL	22.7	396.4	0.0	0.0	0.0	419.1

Table B.2: Experiment A: Installed Storage Capacity (GWh)

B.1.3 Exp. A - SCOE

ID	TM	EI	INV+F	VOM	DR	SUP	Total
1	TM0	0	69.0	0.1	0.0	0.0	69.0
1	TM0	0	55.7	0.3	0.0	0.0	56.0
1	TM0	0	52.1	0.2	0.0	0.0	52.3
1	TM0	0	48.7	0.2	0.0	0.0	48.9
1	TM0	0	46.8	0.4	0.0	0.0	47.2
1	TM0	0	45.2	0.3	0.0	0.0	45.6
2	TM1	0	67.2	0.1	0.1	0.0	67.4
2	TM1	0	45.3	0.3	0.0	0.0	45.6
2	TM1	0	66.5	0.1	0.0	0.0	66.6
2	TM1	0	50.9	0.2	0.0	0.0	51.2
2	TM1	0	53.4	0.2	0.0	0.0	53.6
2	TM1	0	45.2	0.3	0.0	0.0	45.6
3	TM2	0	46.5	0.2	0.0	0.0	46.7
3	TM2	0	51.0	0.2	0.0	0.0	51.2
3	TM2	0	45.2	0.3	0.0	0.0	45.6
3	TM2	1	48.6	1.1	0.0	0.1	49.8
3	TM2	1	44.7	1.1	0.0	0.1	45.9
3	TM2	1	44.4	1.1	0.0	0.1	45.6
4	TM3	1	42.1	1.2	0.0	0.1	43.3
4	TM3	1	39.5	1.0	0.0	0.0	40.5
4	TM3	1	49.2	1.0	0.0	0.1	50.4
4	TM3	1	39.5	1.1	0.0	0.0	40.7
4	TM3	1	48.5	1.0	0.0	0.1	49.6
4	TM3	1	43.9	1.1	0.0	0.1	45.1
5	TM4	1	44.7	1.1	0.0	0.1	45.9
5	TM4	1	39.5	1.0	0.0	0.0	40.5
5	TM4	1	40.8	1.3	0.0	0.1	42.2
5	TM4	1	43.5	1.2	0.0	0.1	44.8
5	TM4	1	39.5	1.0	0.0	0.0	40.5
6	TM5	10	38.0	3.8	0.0	0.3	42.2
6	TM5	10	37.9	2.8	0.0	0.2	41.0
6	TM5	10	37.9	2.8	0.0	0.2	41.0
6	TM5	10	37.9	1.7	0.0	0.1	39.7

Table B.3 continued from previous page

ID	TM	EI	INV+F	VOM	DR	SUP	Total
6	TM5	10	37.3	1.6	0.0	0.1	39.0
6	TM5	10	35.8	1.5	0.0	0.1	37.4
7	TM6	10	38.7	3.8	0.0	0.4	42.9
7	TM6	10	35.8	1.6	0.0	0.1	37.5
7	TM6	10	38.0	3.8	0.0	0.3	42.2
7	TM6	10	38.1	2.6	0.0	0.2	40.9
7	TM6	10	37.9	2.8	0.0	0.2	41.0
7	TM6	10	35.8	1.5	0.0	0.1	37.4
8	TM7	10	37.4	1.3	0.0	0.1	38.7
8	TM7	10	38.3	2.2	0.0	0.2	40.7
8	TM7	10	35.8	1.5	0.0	0.1	37.4
8	TM7	5	40.2	3.4	0.0	0.3	43.9
8	TM7	5	39.5	2.7	0.0	0.2	42.4
8	TM7	5	39.5	2.7	0.0	0.2	42.4
9	TM8	5	38.9	2.0	0.0	0.1	41.0
9	TM8	5	38.2	1.9	0.0	0.1	40.1
9	TM8	5	36.7	1.7	0.0	0.1	38.4
9	TM8	5	40.9	3.4	0.0	0.4	44.7
9	TM8	5	36.8	1.7	0.0	0.1	38.6
9	TM8	5	40.2	3.4	0.0	0.3	43.9
10	TM9	5	39.6	2.5	0.0	0.2	42.2
10	TM9	5	39.5	2.7	0.0	0.2	42.4
10	TM9	5	36.7	1.7	0.0	0.1	38.4
10	TM9	5	38.4	1.6	0.0	0.1	40.1
10	TM9	5	39.5	2.4	0.0	0.2	42.0
10	TM9	5	36.7	1.7	0.0	0.1	38.4
11	TM10	50	32.4	4.2	0.0	0.3	37.0
11	TM10	50	31.8	4.3	0.0	0.3	36.4
11	TM10	50	31.8	4.3	0.0	0.3	36.4
11	TM10	50	31.4	4.4	0.0	0.2	36.0
11	TM10	50	31.1	4.5	0.0	0.1	35.7
11	TM10	50	30.1	4.4	0.0	0.1	34.6
12	TM11	50	33.1	4.2	0.0	0.3	37.6
12	TM11	50	30.2	4.4	0.0	0.1	34.8

Table B.3 continued from previous page

ID	TM	EI	INV+F	VOM	DR	SUP	Total
12	TM11	50	32.4	4.2	0.0	0.3	37.0
12	TM11	50	31.8	4.3	0.0	0.3	36.4
12	TM11	50	31.8	4.3	0.0	0.3	36.4
12	TM11	50	30.1	4.4	0.0	0.1	34.6
13	TM12	50	30.9	4.5	0.0	0.1	35.5
13	TM12	50	31.8	4.3	0.0	0.3	36.4
13	TM12	50	30.1	4.4	0.0	0.1	34.6
13	TM12	NL	28.2	7.6	0.1	0.3	36.2
13	TM12	NL	28.1	7.3	0.0	0.2	35.6
13	TM12	NL	28.1	7.3	0.0	0.2	35.6
14	TM13	NL	28.4	7.0	0.0	0.2	35.6
14	TM13	NL	28.4	6.8	0.0	0.2	35.4
14	TM13	NL	28.0	6.3	0.0	0.2	34.4
14	TM13	NL	28.4	7.9	0.0	0.4	36.7
14	TM13	NL	28.0	6.4	0.0	0.1	34.5
14	TM13	NL	28.2	7.6	0.1	0.3	36.2
15	TM14	NL	28.1	7.3	0.0	0.2	35.6
15	TM14	NL	28.1	7.3	0.0	0.2	35.6
15	TM14	NL	28.0	6.3	0.0	0.2	34.4
15	TM14	NL	28.8	6.4	0.0	0.1	35.3
15	TM14	NL	28.1	7.3	0.0	0.2	35.6
15	TM14	NL	28.0	6.3	0.0	0.2	34.4

Table B.3: Experiment A: System Average Cost, SCOE ($MWh). INV+F: Invesment + Fixed O&M Costs; VOM: Variable Operations and maintenance costs; DR: Demand response

B.1.4 Exp. A - Prices Distribution

ID	TM	EI	<0	0-5	5-50	50-200	200-1000	>1000	Mean	CoV
1	TM0	0	0.00	99.69	0.00	0.00	0.00	0.31	64.27	19.21
1	TM0	1	0.00	84.71	0.01	3.40	11.13	0.75	49.81	7.06
1	TM0	5	0.00	61.80	2.45	30.09	5.60	0.07	42.06	9.81
1	TM0	10	0.00	57.25	8.02	34.38	0.32	0.03	40.48	10.94

Table B.4 continued from previous page

ID	TM	EI	<0	0-5	5-50	50-200	200-1000	>1000	Mean	CoV
1	TM0	50	0.00	41.88	48.52	9.49	0.09	0.01	34.14	17.64
1	TM0	NL	0.04	19.13	78.89	1.92	0.00	0.02	31.02	18.32
2	TM1	0	0.00	99.07	0.00	0.00	0.42	0.52	47.77	19.90
2	TM1	1	0.63	80.97	0.00	16.45	1.71	0.25	42.71	7.65
2	TM1	5	0.00	62.84	7.71	27.82	1.56	0.07	39.70	7.39
2	TM1	10	0.00	60.34	12.91	26.20	0.48	0.07	38.77	7.47
2	TM1	50	0.00	40.40	52.06	7.44	0.03	0.07	34.86	8.80
2	TM1	NL	0.00	16.76	81.25	1.94	0.00	0.05	31.35	12.54
3	TM2	0	0.00	98.55	0.07	0.00	0.02	1.35	44.46	11.47
3	TM2	1	0.00	77.98	1.35	18.61	1.88	0.18	42.20	7.80
3	TM2	5	0.00	62.43	8.27	27.78	1.46	0.07	39.65	7.39
3	TM2	10	0.00	60.34	12.91	26.20	0.48	0.07	38.77	7.47
3	TM2	50	0.00	40.40	52.06	7.44	0.03	0.07	34.86	8.80
3	TM2	NL	0.00	16.76	81.25	1.94	0.00	0.05	31.35	12.54
4	TM3	0	0.00	97.88	0.92	0.00	0.00	1.19	42.55	11.40
4	TM3	1	0.26	68.15	11.64	17.19	2.44	0.33	39.60	6.78
4	TM3	5	0.01	59.28	13.79	26.07	0.66	0.20	37.97	6.89
4	TM3	10	0.00	57.86	15.70	25.77	0.47	0.20	37.50	7.03
4	TM3	50	0.00	24.66	71.37	3.88	0.00	0.10	33.44	10.18
4	TM3	NL	0.00	13.60	84.55	1.76	0.00	0.09	31.40	12.32
5	TM4	0	0.00	97.75	0.04	0.46	0.00	1.75	41.58	11.10
5	TM4	5	0.28	60.62	10.53	27.80	0.57	0.20	37.27	7.69
5	TM4	10	0.15	61.01	13.06	25.42	0.19	0.17	36.75	7.92
5	TM4	50	0.00	24.43	71.77	3.70	0.00	0.10	32.99	11.60
5	TM4	NL	0.00	10.79	87.16	1.95	0.00	0.09	31.32	12.68
6	TM5	0	0.00	98.17	0.00	0.00	1.00	0.83	41.28	11.07
6	TM5	1	0.00	79.80	0.01	17.60	2.19	0.40	37.70	4.61
6	TM5	5	0.00	66.13	5.85	27.59	0.30	0.14	35.93	5.70
6	TM5	10	0.64	64.15	4.64	30.31	0.12	0.14	35.57	5.71
6	TM5	50	0.11	29.31	67.76	2.73	0.00	0.09	32.28	7.54
6	TM5	NL	0.02	16.54	81.97	1.38	0.00	0.09	31.28	7.86
7	TM6	0	0.00	99.70	0.00	0.00	0.00	0.30	56.03	20.48
7	TM6	1	0.00	84.69	0.00	6.87	7.70	0.74	49.11	7.49
7	TM6	5	0.00	62.20	3.71	28.46	5.56	0.08	42.14	7.36

Table B.4 continued from previous page

ID	TM	EI	<0	0-5	5-50	50-200	200-1000	>1000	Mean	CoV
7	TM6	10	0.00	57.32	7.89	34.25	0.46	0.08	40.72	9.01
7	TM6	50	0.04	42.91	44.28	12.73	0.03	0.02	34.92	14.84
7	TM6	NL	0.00	19.31	78.47	2.19	0.00	0.02	31.04	17.04
8	TM7	0	0.00	98.12	0.00	0.00	1.05	0.84	41.70	11.84
8	TM7	1	0.00	79.62	0.26	17.71	1.99	0.43	37.68	6.88
8	TM7	5	0.00	66.11	6.29	26.91	0.56	0.14	36.08	7.57
8	TM7	10	0.00	65.18	4.18	30.16	0.35	0.14	35.67	7.62
8	TM7	50	0.00	29.14	68.51	2.26	0.00	0.09	32.40	9.11
8	TM7	NL	0.00	15.62	82.88	1.41	0.00	0.09	31.38	8.74
9	TM8	0	0.00	99.69	0.00	0.00	0.00	0.31	56.47	19.23
9	TM8	1	0.00	84.49	0.03	6.09	8.64	0.75	49.01	7.50
9	TM8	5	0.00	61.80	2.45	30.09	5.60	0.07	42.06	9.81
9	TM8	10	0.00	57.25	8.02	34.38	0.32	0.03	40.48	10.94
9	TM8	50	0.00	41.88	48.52	9.49	0.09	0.01	34.14	17.64
9	TM8	NL	0.04	19.12	78.89	1.92	0.00	0.02	31.02	18.32
10	TM9	0	0.79	97.65	0.06	0.00	0.43	1.06	43.37	12.42
10	TM9	1	0.00	76.54	1.74	19.39	2.22	0.10	41.19	7.87
10	TM9	5	0.00	60.28	10.78	27.85	1.03	0.07	39.18	7.54
10	TM9	10	0.00	59.48	12.44	27.61	0.41	0.07	38.53	7.47
10	TM9	50	0.00	40.40	52.06	7.44	0.03	0.07	34.86	8.80
10	TM9	NL	0.00	16.76	81.25	1.94	0.00	0.05	31.35	12.54
11	TM10	0	0.00	98.56	0.12	0.13	0.40	0.79	45.77	14.35
11	TM10	1	0.00	80.01	1.31	16.73	1.72	0.23	42.61	7.72
11	TM10	5	0.00	62.84	7.71	27.82	1.56	0.07	39.70	7.39
11	TM10	10	0.00	60.34	12.91	26.20	0.48	0.07	38.77	7.47
11	TM10	50	0.00	40.40	52.06	7.44	0.03	0.07	34.86	8.80
11	TM10	NL	0.00	16.76	81.25	1.94	0.00	0.05	31.35	12.54
12	TM11	0	0.00	98.17	0.00	0.00	1.00	0.83	41.28	11.07
12	TM11	1	0.00	79.80	0.01	17.60	2.19	0.40	37.70	4.61
12	TM11	5	0.00	66.13	5.85	27.59	0.30	0.14	35.93	5.70
12	TM11	10	0.01	64.78	4.64	30.31	0.12	0.14	35.57	5.71
12	TM11	50	0.10	29.33	67.76	2.73	0.00	0.09	32.28	7.54
12	TM11	NL	0.04	16.52	81.97	1.38	0.00	0.09	31.28	7.86
13	TM12	0	0.00	97.08	1.51	0.00	0.19	1.22	40.21	10.90

Table B.4 continued from previous page

ID	TM	EI	<0	0-5	5-50	50-200	200-1000	>1000	Mean	CoV
13	TM12	1	0.12	58.85	21.54	16.38	2.70	0.40	38.45	6.88
13	TM12	5	0.00	51.29	25.46	21.52	1.67	0.07	37.39	6.98
13	TM12	10	0.00	50.01	25.24	23.18	1.54	0.04	36.91	7.00
13	TM12	50	0.00	14.74	81.30	3.70	0.20	0.06	32.82	10.62
13	TM12	NL	0.00	6.44	91.27	2.07	0.16	0.06	31.46	12.61
14	TM13	0	0.00	97.40	1.01	0.00	0.24	1.34	44.05	10.50
14	TM13	1	0.00	73.76	5.95	17.83	2.16	0.31	41.21	6.60
14	TM13	5	0.00	58.67	13.16	27.29	0.78	0.09	39.04	7.24
14	TM13	10	0.00	57.36	15.94	26.31	0.30	0.09	38.37	7.66
14	TM13	50	0.00	39.10	53.55	7.25	0.03	0.07	34.82	8.82
14	TM13	NL	0.00	16.76	81.25	1.94	0.00	0.05	31.35	12.54
15	TM14	0	0.00	98.17	0.00	0.00	1.00	0.83	41.28	11.07
15	TM14	1	0.00	79.80	0.01	17.60	2.19	0.40	37.70	4.61
15	TM14	5	0.00	66.13	5.85	27.59	0.30	0.14	35.93	5.70
15	TM14	10	0.15	64.64	4.64	30.31	0.12	0.14	35.57	5.71
15	TM14	50	0.07	29.36	67.76	2.73	0.00	0.09	32.28	7.54
15	TM14	NL	0.04	16.52	81.97	1.38	0.00	0.09	31.28	7.86

Table B.4: Experiment A: Price distributions (%)

B.2 Experiment Group B

B.2.1 Exp. B - Installed Power Capacity

ID	TM	EI	CCGT	OCGT	CCS	Wind	PV	Li	RFB	H2	Ma	Total
16	TM15	0	0	0	0	270	194	85	0	0	0	549
16	TM15	1	12	4	28	138	162	59	0	0	0	402
16	TM15	5	19	14	22	121	133	49	0	0	0	357
16	TM15	10	28	15	13	119	130	47	0	0	0	352
16	TM15	50	49	20	0	94	105	34	0	0	0	302
16	TM15	NL	51	20	0	90	100	32	0	0	0	293
17	TM16	0	0	0	0	244	156	13	76	0	0	488
17	TM16	1	10	6	20	165	127	15	46	0	0	389
17	TM16	5	20	13	13	141	122	16	36	0	0	361
17	TM16	10	28	14	5	138	124	17	34	0	0	360
17	TM16	50	48	18	0	99	100	22	15	0	0	302
17	TM16	NL	49	18	0	96	94	21	15	0	0	294
18	TM17	0	0	0	0	228	127	9	61	23	0	447
18	TM17	1	9	5	18	157	127	16	37	12	0	381
18	TM17	5	20	12	13	141	122	16	34	2	0	361
18	TM17	10	28	14	5	138	124	17	34	0	0	360
18	TM17	50	48	18	0	99	100	22	15	0	0	302
18	TM17	NL	49	18	0	96	94	21	15	0	0	294
19	TM18	0	0	0	0	217	134	7	49	0	36	443
19	TM18	1	11	0	11	159	126	16	31	0	27	381
19	TM18	5	26	0	2	146	127	17	27	0	24	370
19	TM18	10	32	1	0	138	122	18	25	0	21	358
19	TM18	50	46	13	0	99	96	21	15	0	7	298
19	TM18	NL	46	13	0	99	96	21	15	0	7	297
20	TM19	0	0	0	0	238	162	42	48	0	0	490
20	TM19	1	10	6	20	163	127	51	22	0	0	399
20	TM19	5	19	14	14	142	122	52	13	0	0	376
20	TM19	10	28	15	6	138	124	51	10	0	0	372
20	TM19	50	46	20	0	100	99	43	0	0	0	308
20	TM19	NL	46	21	0	98	95	43	0	0	0	303
21	TM20	0	0	0	0	224	128	43	28	22	0	444

Table B.5 continued from previous page

ID	TM	EI	CCGT	OCGT	CCS	Wind	PV	Li	RFB	H2	Ma	Total
21	TM20	1	11	5	17	156	130	50	11	13	0	391
21	TM20	5	20	13	13	141	123	51	10	3	0	374
21	TM20	10	28	15	6	138	124	51	10	0	0	372
21	TM20	50	46	20	0	100	99	43	0	0	0	308
21	TM20	NL	46	21	0	98	95	43	0	0	0	303
22	TM21	0	0	0	0	211	135	46	13	0	33	439
22	TM21	1	12	0	12	150	132	47	1	0	29	383
22	TM21	5	27	0	2	142	130	47	0	0	25	373
22	TM21	10	32	2	0	136	124	47	0	0	21	361
22	TM21	50	44	15	0	102	96	41	0	0	7	305
22	TM21	NL	44	15	0	102	96	41	0	0	7	305
23	TM22	0	0	0	0	254	194	87	0	0	0	534
23	TM22	1	13	1	30	152	142	65	0	0	0	403
23	TM22	5	14	12	34	114	112	46	0	0	0	332
23	TM22	10	22	14	27	106	105	43	0	0	0	317
23	TM22	50	50	16	0	99	100	36	0	0	0	302
24	TM23	NL	76	18	0	70	50	19	0	0	0	233
24	TM23	0	0	0	0	266	105	7	88	0	0	466
24	TM23	1	10	0	24	168	110	14	53	0	0	379
24	TM23	5	15	12	26	131	99	15	36	0	0	334
24	TM23	10	23	14	19	123	98	14	33	0	0	324
24	TM23	50	50	15	0	102	97	18	20	0	0	301
25	TM24	NL	68	12	0	84	49	4	24	0	0	241
25	TM24	0	0	0	0	214	128	7	62	23	0	435
25	TM24	1	6	4	22	162	109	11	44	12	0	370
25	TM24	5	15	11	25	131	99	15	36	1	0	334
25	TM24	10	23	14	19	123	98	14	33	0	0	324
25	TM24	50	50	15	0	102	97	18	20	0	0	301
25	TM24	NL	68	12	0	84	49	4	24	0	0	241
26	TM25	0	0	0	0	209	137	8	51	0	34	438
26	TM25	1	5	0	21	158	112	14	33	0	25	367
26	TM25	5	19	2	19	132	105	17	25	0	18	336
26	TM25	10	29	0	12	128	106	18	23	0	17	333
26	TM25	NL	68	12	0	84	49	4	24	0	0	241

Table B.5 continued from previous page

ID	TM	EI	CCGT	OCGT	CCS	Wind	PV	Li	RFB	H2	Ma	Total

Table B.5: Experiment B: Installed power capacity (GW)

B.2.2 Exp. B - Energy Storage Capacity

ID	TM	EI	Li-ion	RFB	Hydrogen	Metal-air	Total
16	TM15	0	887	0	0	0	887
16	TM15	1	257	0	0	0	257
16	TM15	5	169	0	0	0	169
16	TM15	10	163	0	0	0	163
16	TM15	50	89	0	0	0	89
16	TM15	NL	82	0	0	0	82
17	TM16	0	19	1559	0	0	1578
17	TM16	1	22	641	0	0	663
17	TM16	5	24	409	0	0	432
17	TM16	10	23	367	0	0	391
17	TM16	50	35	97	0	0	132
17	TM16	NL	33	101	0	0	134
18	TM17	0	11	807	1883	0	2701
18	TM17	1	22	389	648	0	1059
18	TM17	5	23	371	110	0	504
18	TM17	10	23	367	0	0	391
18	TM17	50	35	97	0	0	132
18	TM17	NL	33	101	0	0	134
19	TM18	0	7	412	0	3918	4336
19	TM18	1	22	217	0	1790	2030
19	TM18	5	24	175	0	1467	1666
19	TM18	10	25	155	0	1096	1277
19	TM18	50	35	98	0	348	481
19	TM18	NL	35	98	0	344	476
20	TM19	0	196	1321	0	0	1516
20	TM19	1	163	484	0	0	646
20	TM19	5	163	215	0	0	378
20	TM19	10	158	164	0	0	322

Table B.6 continued from previous page

ID	TM	EI	Li-ion	RFB	Hydrogen	Metal-air	Total
20	TM19	50	133	0	0	0	133
20	TM19	NL	133	0	0	0	133
21	TM20	0	225	621	1865	0	2711
21	TM20	1	174	179	713	0	1066
21	TM20	5	164	162	145	0	471
21	TM20	10	158	164	0	0	322
21	TM20	50	133	0	0	0	133
21	TM20	NL	133	0	0	0	133
22	TM21	0	264	197	0	4215	4676
22	TM21	1	174	15	0	1803	1992
22	TM21	5	172	0	0	1454	1627
22	TM21	10	168	0	0	1079	1247
22	TM21	50	134	0	0	297	432
22	TM21	NL	134	0	0	297	432
23	TM22	0	951	0	0	0	951
23	TM22	1	316	0	0	0	316
23	TM22	5	151	0	0	0	151
23	TM22	10	134	0	0	0	134
23	TM22	50	124	0	0	0	124
24	TM23	NL	60	0	0	0	60
24	TM23	0	7	2261	0	0	2268
24	TM23	1	20	838	0	0	858
24	TM23	5	23	419	0	0	442
24	TM23	10	22	331	0	0	353
24	TM23	50	26	146	0	0	172
25	TM24	NL	7	138	0	0	145
25	TM24	0	7	846	2359	0	3211
25	TM24	1	15	483	912	0	1410
25	TM24	5	23	404	49	0	476
25	TM24	10	22	331	0	0	353
25	TM24	50	26	146	0	0	172
25	TM24	NL	7	138	0	0	145
26	TM25	0	8	441	0	4196	4645
26	TM25	1	20	247	0	1992	2259

Table B.6 continued from previous page

ID	TM	EI	Li-ion	RFB	Hydrogen	Metal-air	Total
26	TM25	5	24	174	0	1040	1238
26	TM25	10	26	157	0	998	1181
26	TM25	NL	7	138	0	0	145

Table B.6: Experiment B: Installed Storage Capacity (GWh)

B.2.3 Exp. B - SCOE

ID	TM	EI	INV+F	VOM	DR	SUP	Total
16	TM15	0	56.4	0.1	0.0	0.0	56.5
16	TM15	1	39.9	1.0	0.0	0.1	40.9
16	TM15	5	34.1	2.3	0.0	0.2	36.6
16	TM15	10	32.6	2.3	0.0	0.2	35.1
16	TM15	50	26.4	4.2	0.1	0.3	31.0
16	TM15	NL	25.6	4.9	0.2	0.3	31.0
17	TM16	0	46.5	0.1	0.1	0.0	46.8
17	TM16	1	37.2	0.9	0.0	0.1	38.2
17	TM16	5	33.5	1.7	0.0	0.2	35.3
17	TM16	10	32.3	1.5	0.0	0.2	33.9
17	TM16	50	26.0	4.2	0.0	0.3	30.5
17	TM16	NL	25.4	4.9	0.0	0.3	30.5
18	TM17	0	43.0	0.2	0.0	0.0	43.2
18	TM17	1	36.9	0.9	0.0	0.1	37.9
18	TM17	5	33.5	1.6	0.0	0.2	35.3
18	TM17	10	32.3	1.5	0.0	0.2	33.9
18	TM17	50	26.0	4.2	0.0	0.3	30.5
18	TM17	NL	25.4	4.9	0.0	0.3	30.5
19	TM18	0	39.5	0.2	0.0	0.0	39.7
19	TM18	1	34.7	0.9	0.0	0.0	35.6
19	TM18	5	32.6	0.9	0.0	0.1	33.6
19	TM18	10	31.2	1.1	0.0	0.1	32.4
19	TM18	50	25.9	4.3	0.0	0.2	30.4
19	TM18	NL	25.8	4.4	0.0	0.2	30.4
20	TM19	0	45.8	0.1	0.0	0.0	45.9

Table B.7 continued from previous page

ID	TM	EI	INV+F	VOM	DR	SUP	Total
20	TM19	1	36.4	0.9	0.0	0.1	37.4
20	TM19	5	32.7	1.7	0.0	0.1	34.5
20	TM19	10	31.4	1.6	0.0	0.1	33.2
20	TM19	50	25.3	4.2	0.0	0.2	29.8
20	TM19	NL	24.9	4.6	0.0	0.2	29.8
21	TM20	0	42.3	0.2	0.0	0.0	42.5
21	TM20	1	36.2	0.9	0.0	0.0	37.1
21	TM20	5	32.8	1.6	0.0	0.1	34.5
21	TM20	10	31.4	1.6	0.0	0.1	33.2
21	TM20	50	25.3	4.2	0.0	0.2	29.8
21	TM20	NL	24.9	4.6	0.0	0.2	29.8
22	TM21	0	38.9	0.2	0.0	0.0	39.1
22	TM21	1	33.9	0.8	0.0	0.0	34.8
22	TM21	5	31.8	0.9	0.0	0.0	32.8
22	TM21	10	30.4	1.1	0.0	0.1	31.5
22	TM21	50	25.3	4.2	0.0	0.2	29.7
22	TM21	NL	25.3	4.2	0.0	0.2	29.7
23	TM22	0	79.3	0.1	0.0	0.0	79.3
23	TM22	1	55.4	1.1	0.0	0.1	56.6
23	TM22	5	44.8	4.0	0.0	0.3	49.2
23	TM22	10	41.9	5.0	0.0	0.4	47.2
23	TM22	50	37.0	4.2	0.0	0.3	41.6
24	TM23	NL	26.6	12.7	0.0	0.2	39.5
24	TM23	0	64.0	0.3	0.0	0.0	64.3
24	TM23	1	51.0	1.2	0.0	0.1	52.3
24	TM23	5	44.1	3.5	0.0	0.2	47.8
24	TM23	10	41.9	4.0	0.0	0.3	46.2
24	TM23	50	36.4	4.3	0.0	0.3	41.0
25	TM24	NL	27.3	11.6	0.0	0.1	39.1
25	TM24	0	59.9	0.2	0.0	0.0	60.1
25	TM24	1	50.5	1.2	0.0	0.1	51.8
25	TM24	5	44.1	3.5	0.0	0.2	47.8
25	TM24	10	41.9	4.0	0.0	0.3	46.2

Table B.7 continued from previous page

ID	TM	EI	INV+F	VOM	DR	SUP	Total
25	TM24	50	36.4	4.3	0.0	0.3	41.0
25	TM24	NL	27.3	11.6	0.0	0.1	39.1
26	TM25	0	56.7	0.2	0.0	0.0	56.8
26	TM25	1	48.1	1.4	0.0	0.1	49.5
26	TM25	5	43.4	3.0	0.0	0.1	46.6
26	TM25	10	42.2	2.8	0.0	0.1	45.2
26	TM25	NL	27.3	11.6	0.0	0.1	39.1

Table B.7: Experiment B: System Average Cost, SCOE ($MWh). INV+F: Invesment + Fixed O&M Costs; VOM: Variable Operations and maintenance costs; DR: Demand response; UR: Unmet Reserves; NE: Network expansion

B.2.4 Exp. B - Prices Distribution

ID	TM	EI	<0	0-5	5-50	50-200	200-1000	>1000	Mean	CoV
1	TM0	0	0.0	99.8	0.0	0.0	0.0	0.2	53.8	24.4
1	TM0	1	0.0	85.9	0.0	12.8	0.5	0.8	41.0	12.2
1	TM0	5	0.0	71.6	2.6	24.6	1.2	0.0	35.0	10.8
1	TM0	10	0.0	69.9	4.3	25.4	0.4	0.0	34.1	11.4
1	TM0	50	0.0	44.5	53.3	2.2	0.0	0.0	26.3	22.1
1	TM0	NL	0.2	39.5	58.4	1.9	0.0	0.0	25.5	22.8
2	TM1	0	0.0	99.8	0.0	0.0	0.0	0.2	38.6	26.9
2	TM1	1	0.0	85.5	0.0	12.2	2.2	0.1	34.8	9.2
2	TM1	5	0.0	75.2	4.3	19.2	1.2	0.1	32.6	8.9
2	TM1	10	0.0	74.2	4.5	20.8	0.4	0.1	31.9	9.2
2	TM1	50	0.0	42.9	53.4	3.7	0.0	0.1	26.8	13.1
2	TM1	NL	0.1	37.2	60.4	2.2	0.0	0.1	26.1	14.0
3	TM2	0	0.0	98.7	0.1	0.0	0.4	0.8	36.2	15.0
3	TM2	1	0.0	82.6	1.6	13.3	2.5	0.1	34.2	9.5
3	TM2	5	0.0	74.7	4.4	19.8	1.1	0.1	32.6	8.9
3	TM2	10	0.0	74.2	4.5	20.8	0.4	0.1	31.9	9.2
3	TM2	50	0.0	42.9	53.4	3.7	0.0	0.1	26.8	13.1
3	TM2	NL	0.1	37.2	60.4	2.2	0.0	0.1	26.1	14.0

Table B.8 continued from previous page

ID	TM	EI	<0	0-5	5-50	50-200	200-1000	>1000	Mean	CoV
4	TM3	0	0.0	97.8	1.0	0.2	0.2	0.7	34.3	13.8
4	TM3	1	0.2	78.3	7.0	11.5	2.7	0.3	32.2	10.9
4	TM3	5	0.0	73.0	7.5	18.5	0.8	0.2	31.2	11.2
4	TM3	10	0.0	66.0	11.5	21.9	0.4	0.2	30.2	10.3
4	TM3	50	0.0	30.9	67.2	1.9	0.0	0.1	26.0	14.7
4	TM3	NL	0.1	30.7	67.3	1.9	0.0	0.1	26.0	14.7
5	TM4	0	0.0	99.8	0.0	0.0	0.0	0.2	38.5	25.9
5	TM4	5	0.0	84.9	0.1	13.1	1.8	0.1	34.8	9.2
5	TM4	10	0.0	74.2	4.1	20.9	0.7	0.1	32.5	9.0
5	TM4	50	0.1	73.4	3.9	22.6	0.1	0.1	31.8	9.1
5	TM4	NL	0.0	41.5	56.7	1.7	0.0	0.1	26.1	14.1
6	TM5	0	0.0	38.2	60.3	1.4	0.0	0.1	25.6	14.8
6	TM5	1	0.0	98.7	0.3	0.4	0.1	0.6	35.8	14.3
6	TM5	5	0.0	82.3	1.6	13.8	2.2	0.1	34.0	9.4
6	TM5	10	0.0	73.7	4.8	20.7	0.7	0.1	32.4	9.0
6	TM5	50	0.0	73.4	3.9	22.6	0.1	0.1	31.8	9.1
6	TM5	NL	0.0	41.5	56.7	1.7	0.0	0.1	26.1	14.1
7	TM6	0	0.1	38.1	60.3	1.4	0.0	0.1	25.6	14.8
7	TM6	1	0.0	97.7	1.1	0.2	0.2	0.7	34.3	13.3
7	TM6	5	0.0	78.5	6.8	11.8	2.7	0.2	32.2	9.8
7	TM6	10	0.0	73.1	7.3	18.8	0.7	0.2	31.1	9.1
7	TM6	50	0.1	66.0	11.4	21.9	0.4	0.2	30.3	9.4
7	TM6	NL	0.1	32.6	65.9	1.4	0.0	0.1	25.6	16.7
8	TM7	0	0.2	32.5	65.9	1.4	0.0	0.1	25.6	16.7
8	TM7	1	0.0	99.7	0.0	0.0	0.0	0.3	73.9	21.5
8	TM7	5	0.0	84.1	0.0	0.2	15.1	0.6	56.6	6.9
8	TM7	10	0.0	56.8	1.6	36.3	5.3	0.1	47.2	6.8
8	TM7	50	0.0	48.8	10.8	40.0	0.4	0.0	44.9	9.6
8	TM7	NL	0.0	41.8	12.6	45.6	0.1	0.0	39.8	15.1
9	TM8	0	0.0	7.6	91.0	1.3	0.0	0.0	34.1	16.1
9	TM8	1	0.0	99.5	0.0	0.0	0.0	0.5	54.8	16.6
9	TM8	5	0.0	80.3	0.0	18.0	0.9	0.8	49.0	7.0
9	TM8	10	0.1	55.3	7.4	35.3	1.8	0.1	44.8	6.6
9	TM8	50	0.0	50.2	20.7	28.6	0.5	0.1	43.6	6.6

Table B.8 continued from previous page

ID	TM	EI	<0	0-5	5-50	50-200	200-1000	>1000	Mean	CoV
9	TM8	NL	0.0	39.6	14.6	45.6	0.0	0.1	40.5	7.5
10	TM9	0	0.0	4.1	94.8	1.1	0.0	0.1	34.3	14.2
10	TM9	1	0.0	98.5	0.0	0.0	0.2	1.3	51.0	10.9
10	TM9	5	0.0	75.7	0.4	22.0	1.6	0.2	48.0	7.0
10	TM9	10	0.0	54.9	8.5	34.8	1.7	0.1	44.8	6.6
10	TM9	50	0.0	50.2	20.7	28.6	0.5	0.1	43.6	6.6
10	TM9	NL	0.0	39.6	14.6	45.6	0.0	0.1	40.5	7.5
11	TM10	0	0.0	4.1	94.8	1.1	0.0	0.1	34.3	14.2
11	TM10	1	0.0	97.7	1.1	0.0	0.0	1.2	49.3	10.6
11	TM10	5	0.0	64.8	11.2	21.3	2.2	0.4	45.4	6.1
11	TM10	10	0.0	47.2	20.8	31.1	0.7	0.2	43.1	6.1
11	TM10	50	0.0	45.0	25.9	28.5	0.4	0.2	42.5	6.2
11	TM10	NL	0.0	4.1	94.8	1.1	0.0	0.1	34.3	14.2

Table B.8: Experiment B: Price distributions (%)

B.3 Experiment Group C

B.3.1 Exp. C - Installed Power Capacity

ID	TM	EI	CCGT	OCGT	CCS	Wind	PV	Li	RFB	H2	Ma	Total
27	TM0	0	0	0	0	137	237	62	0	0	0	436
27	TM0	1	11	2	24	113	119	43	0	0	0	311
27	TM0	5	13	11	24	93	87	32	0	0	0	260
27	TM0	10	20	13	18	91	80	28	0	0	0	250
27	TM0	50	40	16	0	82	71	22	0	0	0	231
27	TM0	NL	50	19	0	63	53	14	0	0	0	198
28	TM1	0	0	0	0	75	218	3	73	0	0	368
28	TM1	1	8	3	19	85	136	6	42	0	0	298
28	TM1	5	14	11	16	80	109	7	31	0	0	267
28	TM1	10	20	12	11	81	102	7	27	0	0	261
28	TM1	50	39	14	0	77	76	10	15	0	0	231
28	TM1	NL	46	15	0	58	63	8	14	0	0	204
29	TM2	0	0	0	0	99	174	1	49	19	0	342
29	TM2	1	6	5	17	86	131	5	36	8	0	294
29	TM2	5	14	11	16	80	109	7	30	0	0	267
29	TM2	10	20	12	11	81	102	7	27	0	0	261
29	TM2	50	39	14	0	77	76	10	15	0	0	231
29	TM2	NL	46	15	0	58	63	8	14	0	0	204
30	TM3	0	0	0	0	103	172	0	41	0	29	344
30	TM3	1	7	0	14	89	126	5	26	0	20	287
30	TM3	5	18	2	10	85	110	7	22	0	15	269
30	TM3	10	25	1	5	86	106	6	22	0	15	265
30	TM3	50	40	6	0	74	74	8	12	0	10	224
30	TM3	NL	46	13	0	60	62	6	12	0	3	202

Table B.9: Experiment C: Installed power capacity (GW)

B.3.2 Exp. C - Energy Storage Capacity

ID	TM	EI	Li-ion	RFB	Hydrogen	Metal-air	Total
27	TM0	0	718	0	0	0	718
27	TM0	1	232	0	0	0	232
27	TM0	5	119	0	0	0	119
27	TM0	10	92	0	0	0	92
27	TM0	50	70	0	0	0	70
27	TM0	NL	32	0	0	0	32
28	TM1	0	3	1918	0	0	1921
28	TM1	1	7	605	0	0	613
28	TM1	5	9	353	0	0	363
28	TM1	10	10	292	0	0	302
28	TM1	50	13	106	0	0	119
28	TM1	NL	10	96	0	0	106
29	TM2	0	1	714	1642	0	2357
29	TM2	1	5	399	536	0	940
29	TM2	5	9	351	11	0	370
29	TM2	10	10	292	0	0	302
29	TM2	50	13	106	0	0	119
29	TM2	NL	10	96	0	0	106
30	TM3	0	0	334	0	3264	3598
30	TM3	1	5	216	0	1464	1685
30	TM3	5	8	173	0	818	999
30	TM3	10	7	165	0	827	999
30	TM3	50	13	72	0	484	568
30	TM3	NL	8	78	0	70	157

Table B.10: Experiment C: Installed Storage Capacity (GWh)

B.3.3 Exp. C - SCOE

ID	TM	EI	INV+F	VOM	DR	SUP	Total
27	TM0	0	72.0	0.1	0.3	0.0	72.4
27	TM0	1	50.2	1.0	0.0	0.1	51.4
27	TM0	5	41.4	3.5	0.0	0.3	45.1
27	TM0	10	38.9	4.0	0.0	0.3	43.2
27	TM0	50	33.2	4.2	0.0	0.3	37.6

Table B.11 continued from previous page

ID	TM	EI	INV+F	VOM	DR	SUP	Total
27	TM0	NL	28.0	8.2	0.0	0.3	36.5
28	TM1	0	58.2	0.3	0.0	0.0	58.5
28	TM1	1	46.2	1.1	0.0	0.1	47.4
28	TM1	5	40.6	2.7	0.0	0.2	43.5
28	TM1	10	38.8	3.0	0.0	0.2	42.0
28	TM1	50	32.6	4.2	0.0	0.2	37.1
28	TM1	NL	28.2	7.7	0.0	0.2	36.1
29	TM2	0	54.1	0.2	0.1	0.0	54.4
29	TM2	1	45.9	1.1	0.0	0.1	47.1
29	TM2	5	40.6	2.7	0.0	0.2	43.5
29	TM2	10	38.8	3.0	0.0	0.2	42.0
29	TM2	50	32.6	4.2	0.0	0.2	37.1
29	TM2	NL	28.2	7.7	0.0	0.2	36.1
30	TM3	0	50.3	0.2	0.1	0.0	50.6
30	TM3	1	43.4	1.2	0.1	0.1	44.7
30	TM3	5	39.8	2.2	0.0	0.1	42.1
30	TM3	10	38.7	1.9	0.1	0.1	40.7
30	TM3	50	32.1	4.4	0.1	0.2	36.7
30	TM3	NL	28.3	7.5	0.1	0.2	36.1

Table B.11: Experiment C: System Average Cost, SCOE ($MWh). INV+F: Invesment + Fixed O&M Costs; VOM: Variable Operations and maintenance costs; DR: Demand response; UR: Unmet Reserves; NE: Network expansion

B.3.4 Exp. C - Prices Distribution

ID	TM	EI	<0	0-5	5-50	50-200	200-1000	>1000	Mean	CoV
27	TM0	0	0.0	99.7	0.0	0.0	0.1	0.2	56.4	27.4
27	TM0	1	0.0	85.6	0.1	2.7	10.9	0.7	49.4	7.6
27	TM0	5	0.0	63.0	1.1	30.5	5.3	0.0	42.1	11.1
27	TM0	10	0.0	57.9	7.3	34.5	0.3	0.0	40.3	12.1
27	TM0	50	0.0	45.6	38.1	16.2	0.1	0.0	35.2	15.8
27	TM0	NL	0.0	19.6	78.9	1.4	0.0	0.0	31.2	17.5

Table B.12 continued from previous page

ID	TM	EI	<0	0-5	5-50	50-200	200-1000	>1000	Mean	CoV
28	TM1	0	0.0	99.1	0.4	0.0	0.0	0.5	47.4	20.0
28	TM1	1	0.0	82.6	0.0	15.6	1.5	0.2	42.4	7.9
28	TM1	5	0.0	63.9	6.7	27.8	1.5	0.1	39.4	7.5
28	TM1	10	0.0	60.8	6.0	32.8	0.3	0.1	38.5	7.6
28	TM1	50	0.0	43.6	41.6	14.7	0.0	0.1	35.0	9.7
28	TM1	NL	0.0	16.5	81.9	1.5	0.0	0.1	31.5	15.0
29	TM2	0	0.0	98.5	0.0	0.0	0.1	1.4	44.3	11.9
29	TM2	1	0.0	78.6	1.2	18.2	1.8	0.2	41.6	8.3
29	TM2	5	0.0	63.8	6.8	27.8	1.5	0.1	39.4	7.5
29	TM2	10	0.0	60.8	6.0	32.8	0.3	0.1	38.5	7.6
29	TM2	50	0.0	43.6	41.6	14.7	0.0	0.1	35.0	9.7
29	TM2	NL	0.0	16.5	81.9	1.5	0.0	0.1	31.5	15.0
30	TM3	0	0.0	97.5	1.1	0.0	0.3	1.1	42.1	10.9
30	TM3	1	0.0	70.1	10.8	16.3	2.5	0.3	39.1	7.6
30	TM3	5	0.0	60.7	12.5	25.9	0.7	0.2	37.5	7.7
30	TM3	10	0.0	59.9	14.1	25.4	0.4	0.2	37.0	8.4
30	TM3	50	0.0	27.7	67.5	4.7	0.0	0.1	33.6	12.9
30	TM3	NL	0.0	13.8	84.4	1.7	0.0	0.1	31.5	14.7

Table B.12: Experiment C: Price distributions (%)

B.4 Experiment Group D

B.4.1 Exp. D - Installed Power Capacity

ID	TM	EI	CCGT	OCGT	CCS	Wind	PV	Li	RFB	H2	Ma	Total
31	TM0	0	0	0	0	185	278	75	0	0	0	539
31	TM0	1	12	1	29	146	149	37	0	0	0	374
31	TM0	5	16	13	29	120	113	22	0	0	0	313
31	TM0	10	24	15	22	117	106	18	0	0	0	302
31	TM0	50	49	21	0	107	92	7	0	0	0	276
31	TM0	NL	58	23	0	82	75	0	0	0	0	238
32	TM1	0	0	0	0	110	259	0	75	0	0	445
32	TM1	1	10	2	23	112	171	0	42	0	0	360
32	TM1	5	17	13	20	105	138	0	30	0	0	322
32	TM1	10	25	14	13	107	130	0	25	0	0	314
32	TM1	50	47	18	0	99	100	0	10	0	0	274
32	TM1	NL	53	19	0	79	85	0	8	0	0	245
33	TM2	0	0	0	0	134	212	0	48	22	0	415
33	TM2	1	9	4	20	116	161	0	35	8	0	352
33	TM2	5	17	13	20	105	138	0	30	0	0	322
33	TM2	10	25	14	13	107	130	0	25	0	0	314
33	TM2	50	47	18	0	99	100	0	10	0	0	274
33	TM2	NL	53	19	0	79	85	0	8	0	0	245
34	TM3	0	0	0	0	135	211	0	41	0	33	421
34	TM3	1	8	0	17	120	154	0	21	0	24	344
34	TM3	5	23	0	11	115	137	0	17	0	19	323
34	TM3	10	31	0	4	116	133	0	16	0	20	320
34	TM3	50	47	8	0	96	97	0	7	0	12	268
34	TM3	NL	53	14	0	82	85	0	4	0	8	247

Table B.13: Experiment D: Installed power capacity (GW)

B.4.2 Exp. D - Energy Storage Capacity

ID	TM	EI	Li-ion	RFB	Hydrogen	Metal-air	Total
31	TM0	0	845	0	0	0	845
31	TM0	1	264	0	0	0	264
31	TM0	5	109	0	0	0	109
31	TM0	10	73	0	0	0	73
31	TM0	50	25	0	0	0	25
31	TM0	NL	0	0	0	0	0
32	TM1	0	0	2190	0	0	2190
32	TM1	1	0	730	0	0	730
32	TM1	5	0	410	0	0	410
32	TM1	10	0	335	0	0	335
32	TM1	50	0	103	0	0	103
32	TM1	NL	0	106	0	0	106
33	TM2	0	0	812	2283	0	3095
33	TM2	1	0	530	568	0	1097
33	TM2	5	0	410	0	0	410
33	TM2	10	0	335	0	0	335
33	TM2	50	0	103	0	0	103
33	TM2	NL	0	106	0	0	106
34	TM3	0	0	430	0	4124	4554
34	TM3	1	0	218	0	1792	2010
34	TM3	5	0	170	0	1190	1360
34	TM3	10	0	150	0	1170	1320
34	TM3	50	0	70	0	545	615
34	TM3	NL	0	37	0	212	250

Table B.14: Experiment D: Installed Storage Capacity (GWh)

B.4.3 Exp. D - SCOE

ID	TM	EI	INV+F	VOM	DR	SUP	Total
31	TM0	0	67.7	0.1	0.0	0.0	67.8
31	TM0	1	47.4	1.0	0.0	0.1	48.5
31	TM0	5	39.0	3.3	0.0	0.3	42.5
31	TM0	10	36.7	3.8	0.0	0.3	40.8
31	TM0	50	31.1	4.1	0.0	0.3	35.5

Table B.15 continued from previous page

ID	TM	EI	INV+F	VOM	DR	SUP	Total
31	TM0	NL	26.4	7.8	0.0	0.3	34.5
32	TM1	0	54.8	0.2	0.0	0.0	55.0
32	TM1	1	43.5	1.1	0.0	0.1	44.7
32	TM1	5	38.3	2.6	0.0	0.2	41.1
32	TM1	10	36.7	2.8	0.0	0.2	39.7
32	TM1	50	30.6	4.2	0.0	0.3	35.1
32	TM1	NL	27.1	7.1	0.0	0.2	34.4
33	TM2	0	51.3	0.1	0.0	0.0	51.5
33	TM2	1	43.4	1.0	0.0	0.1	44.4
33	TM2	5	38.3	2.6	0.0	0.2	41.1
33	TM2	10	36.7	2.8	0.0	0.2	39.7
33	TM2	50	30.6	4.2	0.0	0.3	35.1
33	TM2	NL	27.1	7.1	0.0	0.2	34.4
34	TM3	0	47.8	0.2	0.0	0.0	48.0
34	TM3	1	41.0	1.2	0.0	0.1	42.2
34	TM3	5	37.8	2.0	0.0	0.1	39.8
34	TM3	10	36.7	1.7	0.0	0.1	38.5
34	TM3	50	30.2	4.4	0.0	0.2	34.8
34	TM3	NL	27.3	6.9	0.0	0.2	34.4

Table B.15: Experiment D: System Average Cost, SCOE ($MWhs). INV+F: Invesment + Fixed O&M Costs; VOM: Variable Operations and maintenance costs; DR: Demand response; UR: Unmet Reserves; NE: Network expansion

B.4.4 Exp. D - Prices Distribution

ID	TM	EI	<0	0-5	5-50	50-200	200-1000	>1000	Mean	CoV
31	TM0	0	0.0	99.7	0.0	0.0	0.0	0.3	65.6	20.8
31	TM0	1	0.0	84.5	0.0	2.7	12.0	0.7	50.3	6.9
31	TM0	5	0.0	62.0	1.7	30.3	6.0	0.0	42.0	11.3
31	TM0	10	0.0	57.8	4.7	37.1	0.3	0.0	40.3	11.4
31	TM0	50	0.0	45.0	41.7	13.2	0.1	0.0	35.0	15.6
31	TM0	NL	0.0	21.0	76.5	2.5	0.0	0.0	31.4	15.6

Table B.16 continued from previous page

ID	TM	EI	<0	0-5	5-50	50-200	200-1000	>1000	Mean	CoV
32	TM1	0	0.0	99.5	0.0	0.0	0.0	0.5	47.6	19.5
32	TM1	1	0.0	81.6	0.0	16.7	1.5	0.2	42.8	7.7
32	TM1	5	0.0	62.7	6.4	29.5	1.3	0.1	39.6	7.6
32	TM1	10	0.0	60.3	11.1	28.2	0.4	0.1	38.7	7.6
32	TM1	50	0.0	41.7	52.3	5.8	0.1	0.1	34.7	9.0
32	TM1	NL	0.0	18.5	79.9	1.5	0.0	0.0	31.5	14.2
33	TM2	0	0.0	98.9	0.0	0.0	0.2	0.9	44.6	13.0
33	TM2	1	0.0	78.5	0.8	18.7	1.8	0.2	42.2	7.9
33	TM2	5	0.0	62.7	6.4	29.5	1.3	0.1	39.6	7.6
33	TM2	10	0.0	60.3	11.1	28.2	0.4	0.1	38.7	7.6
33	TM2	50	0.0	41.7	52.3	5.8	0.1	0.1	34.7	9.0
33	TM2	NL	0.0	18.5	79.9	1.5	0.0	0.0	31.5	14.2
34	TM3	0	0.0	97.4	1.4	0.0	0.1	1.1	42.8	10.6
34	TM3	1	0.0	68.1	11.6	17.5	2.5	0.3	40.0	5.7
34	TM3	5	0.0	59.2	13.5	26.4	0.7	0.2	37.8	6.0
34	TM3	10	0.0	57.9	15.7	25.7	0.5	0.2	37.3	6.2
34	TM3	50	0.0	25.3	71.3	3.3	0.0	0.1	33.2	11.1
34	TM3	NL	0.0	14.0	84.4	1.5	0.0	0.1	31.4	13.0

Table B.16: Experiment D: Price distributions (%)

B.5 Experiment Group E

B.5.1 Exp. E - Installed Power Capacity

ID	TM	EI	CCGT	OCGT	CCS	Allam	Wind	PV	Li	RFB	H2	Ma	Th	Total
35	TM26	0	0	0	0	0	264	191	87	0	0	0	0	543
35	TM26	1	10	6	2	42	118	107	42	0	0	0	0	327
35	TM26	5	20	14	0	30	109	105	38	0	0	0	0	315
35	TM26	10	27	15	0	22	109	106	38	0	0	0	0	316
35	TM26	50	49	17	0	0	103	98	36	0	0	0	0	303
35	TM26	NL	60	19	0	0	80	80	26	0	0	0	0	265
36	TM27	0	0	0	0	0	226	119	0	62	31	0	0	439
36	TM27	1	10	6	0	28	145	95	10	35	11	0	0	341
36	TM27	5	19	12	0	20	137	95	11	34	4	0	0	332
36	TM27	10	26	14	0	15	133	97	11	34	1	0	0	331
36	TM27	50	49	16	0	0	106	94	18	20	0	0	0	303
36	TM27	NL	57	16	0	0	90	75	12	20	0	0	0	270
37	TM28	0	0	0	0	0	228	124	6	63	24	0	0	445
37	TM28	1	9	8	1	32	146	94	9	39	2	0	0	340
37	TM28	5	19	13	0	22	136	94	10	36	0	0	0	330
37	TM28	10	26	14	0	15	133	96	11	34	0	0	0	330
37	TM28	50	49	16	0	0	106	94	18	20	0	0	0	303
37	TM28	NL	57	16	0	0	90	75	12	20	0	0	0	270
38	TM29	0	0	0	0	0	221	132	9	65	18	0	0	446
38	TM29	1	9	9	1	32	146	93	9	40	0	0	0	339
38	TM29	5	19	13	0	22	136	94	10	36	0	0	0	330
38	TM29	10	26	14	0	15	133	96	11	34	0	0	0	330
38	TM29	50	49	16	0	0	106	94	18	20	0	0	0	303
38	TM29	NL	57	16	0	0	90	75	12	20	0	0	0	270
39	TM30	0	0	0	0	0	202	145	9	38	0	44	0	439
39	TM30	1	8	0	0	20	148	104	17	27	0	26	0	351
39	TM30	5	20	0	0	10	143	109	19	25	0	25	0	350
39	TM30	10	27	0	0	2	142	112	18	25	0	25	0	352
39	TM30	50	47	0	0	0	107	89	20	16	0	20	0	298
39	TM30	NL	53	0	0	0	98	78	15	18	0	18	0	280
40	TM31	0	0	0	0	0	230	127	0	60	0	33	0	449

Table B.17 continued from previous page

ID	TM	EI	CCGT	OCGT	CCS	Allam	Wind	PV	Li	RFB	H2	Ma	Th	Total
40	TM31	1	12	0	0	23	149	99	16	28	0	20	0	347
40	TM31	5	23	2	0	14	141	102	17	25	0	18	0	342
40	TM31	10	31	1	0	7	140	105	18	25	0	18	0	344
40	TM31	50	48	7	0	0	107	90	20	16	0	11	0	299
40	TM31	NL	55	14	0	0	91	76	13	19	0	3	0	272
41	TM32	0	0	0	0	0	246	120	0	66	0	28	0	461
41	TM32	5	20	9	0	19	137	97	13	32	0	8	0	335
41	TM32	10	27	10	0	12	136	99	13	31	0	8	0	336
41	TM32	50	49	15	0	0	106	94	18	19	0	1	0	303
41	TM32	NL	57	16	0	0	90	75	12	20	0	0	0	270
42	TM33	0	0	0	0	0	265	83	12	25	0	0	60	446
42	TM33	1	9	0	0	14	167	95	18	8	0	0	50	361
42	TM33	5	18	0	0	5	160	99	18	5	0	0	51	358
42	TM33	10	24	0	0	0	158	102	18	4	0	0	52	359
42	TM33	50	45	5	0	0	115	84	19	0	0	0	34	302
42	TM33	NL	52	4	0	0	107	76	16	0	0	0	32	287
43	TM34	0	0	0	0	0	268	91	6	46	0	0	44	455
43	TM34	1	12	0	0	19	161	93	18	22	0	0	28	353
43	TM34	5	21	3	0	10	153	96	19	21	0	0	25	348
43	TM34	10	27	3	0	4	151	99	19	21	0	0	25	349
43	TM34	50	45	9	0	0	112	85	19	14	0	0	16	300
43	TM34	NL	54	12	0	0	98	74	14	15	0	0	10	277
44	TM35	0	0	0	0	0	267	106	0	66	0	0	29	468
44	TM35	1	11	4	0	28	153	91	15	29	0	0	13	345
44	TM35	5	20	10	0	18	143	93	15	28	0	0	9	336
44	TM35	10	26	11	0	12	140	96	17	26	0	0	8	336
44	TM35	50	48	15	0	0	108	91	21	16	0	0	3	302
44	TM35	NL	57	16	0	0	91	75	13	19	0	0	0	271

Table B.17: Experiment E: Installed power capacity (GW)

B.5.2 Exp. E - Energy Storage Capacity

ID	TM	EI	Li-ion	RFB	Hydrogen	Metal-air	Thermal	Total
35	TM26	0	916	0	0	0	0	916
35	TM26	1	158	0	0	0	0	158
35	TM26	5	129	0	0	0	0	129
35	TM26	10	126	0	0	0	0	126
35	TM26	50	117	0	0	0	0	117
35	TM26	NL	79	0	0	0	0	79
36	TM27	0	0	557	3035	0	0	3592
36	TM27	1	14	294	623	0	0	932
36	TM27	5	14	307	221	0	0	542
36	TM27	10	15	313	49	0	0	378
36	TM27	50	27	136	0	0	0	162
36	TM27	NL	19	119	0	0	0	138
37	TM28	0	6	801	2057	0	0	2864
37	TM28	1	14	402	103	0	0	519
37	TM28	5	14	354	0	0	0	369
37	TM28	10	15	327	0	0	0	343
37	TM28	50	27	136	0	0	0	162
37	TM28	NL	19	119	0	0	0	138
38	TM29	0	11	1034	1582	0	0	2627
38	TM29	1	15	443	0	0	0	458
38	TM29	5	14	354	0	0	0	369
38	TM29	10	15	327	0	0	0	343
38	TM29	50	27	136	0	0	0	162
38	TM29	NL	19	119	0	0	0	138
39	TM30	0	11	285	0	5226	0	5522
39	TM30	1	25	194	0	2882	0	3101
39	TM30	5	27	182	0	2911	0	3121
39	TM30	10	27	174	0	2991	0	3192
39	TM30	50	32	106	0	1738	0	1875
39	TM30	NL	24	113	0	1511	0	1648
40	TM31	0	0	482	0	3152	0	3634
40	TM31	1	23	201	0	1227	0	1451
40	TM31	5	25	177	0	912	0	1114
40	TM31	10	26	176	0	965	0	1167
40	TM31	50	32	105	0	538	0	675

Table B.18 continued from previous page

ID	TM	EI	Li-ion	RFB	Hydrogen	Metal-air	Thermal	Total
40	TM31	NL	21	116	0	104	0	240
41	TM32	0	0	562	0	2361	0	2923
41	TM32	5	15	257	0	354	0	626
41	TM32	10	17	245	0	338	0	599
41	TM32	50	27	130	0	29	0	187
41	TM32	NL	19	119	0	0	0	138
42	TM33	0	18	140	0	0	6633	6791
42	TM33	1	28	38	0	0	2885	2950
42	TM33	5	28	26	0	0	2733	2787
42	TM33	10	27	17	0	0	2598	2643
42	TM33	50	29	0	0	0	964	992
42	TM33	NL	25	0	0	0	749	773
43	TM34	0	7	382	0	0	3156	3544
43	TM34	1	29	154	0	0	1542	1725
43	TM34	5	29	142	0	0	1245	1416
43	TM34	10	28	135	0	0	1182	1345
43	TM34	50	30	85	0	0	596	710
43	TM34	NL	22	83	0	0	255	360
44	TM35	0	0	584	0	0	1797	2382
44	TM35	1	21	227	0	0	542	790
44	TM35	5	21	224	0	0	379	624
44	TM35	10	24	212	0	0	337	573
44	TM35	50	32	108	0	0	110	250
44	TM35	NL	20	117	0	0	14	151

Table B.18: Experiment E: Installed Storage Capacity (GWh)

B.5.3 Exp. E - SCOE

ID	TM	EI	INV+F	VOM	DR	SUP	Total
35	TM26	0	69.0	0.1	0.0	0.0	69.0
35	TM26	1	41.5	3.9	0.0	0.0	45.4
35	TM26	5	38.2	4.5	0.0	0.1	42.8
35	TM26	10	37.1	4.3	0.0	0.1	41.5

Table B.19 continued from previous page

ID	TM	EI	INV+F	VOM	DR	SUP	Total
35	TM26	50	32.4	4.2	0.0	0.3	37.0
35	TM26	NL	28.2	7.6	0.1	0.3	36.2
36	TM27	0	50.9	0.2	0.0	0.0	51.1
36	TM27	1	40.9	2.8	0.0	0.0	43.6
36	TM27	5	38.3	3.3	0.0	0.1	41.7
36	TM27	10	37.2	3.3	0.0	0.1	40.6
36	TM27	50	31.8	4.3	0.0	0.3	36.4
36	TM27	NL	28.1	7.3	0.0	0.2	35.6
37	TM28	0	52.2	0.2	0.0	0.0	52.4
37	TM28	1	40.8	3.0	0.0	0.0	43.9
37	TM28	5	38.1	3.5	0.0	0.1	41.7
37	TM28	10	37.1	3.4	0.0	0.1	40.6
37	TM28	50	31.8	4.3	0.0	0.3	36.4
37	TM28	NL	28.1	7.3	0.0	0.2	35.6
38	TM29	0	53.7	0.2	0.0	0.0	53.9
38	TM29	1	40.8	3.0	0.0	0.0	43.9
38	TM29	5	38.1	3.5	0.0	0.1	41.7
38	TM29	10	37.1	3.4	0.0	0.1	40.6
38	TM29	50	31.8	4.3	0.0	0.3	36.4
38	TM29	NL	28.1	7.3	0.0	0.2	35.6
39	TM30	0	46.3	0.2	0.0	0.0	46.5
39	TM30	1	39.1	2.3	0.0	0.0	41.4
39	TM30	5	37.8	2.0	0.0	0.0	39.9
39	TM30	10	37.1	1.5	0.0	0.1	38.7
39	TM30	50	30.9	4.5	0.0	0.1	35.5
39	TM30	NL	28.8	6.3	0.0	0.1	35.3
40	TM31	0	48.8	0.2	0.0	0.0	49.0
40	TM31	1	39.8	2.5	0.0	0.0	42.4
40	TM31	5	38.1	2.6	0.0	0.0	40.7
40	TM31	10	37.4	2.1	0.0	0.1	39.6
40	TM31	50	31.5	4.4	0.0	0.2	36.0
40	TM31	NL	28.4	7.0	0.0	0.2	35.6
41	TM32	0	51.1	0.2	0.0	0.0	51.3
41	TM32	5	38.3	3.2	0.0	0.1	41.6

Table B.19 continued from previous page

ID	TM	EI	INV+F	VOM	DR	SUP	Total
41	TM32	10	37.5	2.9	0.0	0.1	40.5
41	TM32	50	31.8	4.3	0.0	0.3	36.4
41	TM32	NL	28.1	7.3	0.0	0.2	35.6
42	TM33	0	43.6	0.5	0.0	0.0	44.1
42	TM33	1	37.9	1.6	0.0	0.0	39.6
42	TM33	5	36.6	1.6	0.0	0.0	38.2
42	TM33	10	36.0	1.2	0.0	0.1	37.3
42	TM33	50	30.1	4.5	0.0	0.1	34.8
42	TM33	NL	28.5	6.1	0.0	0.1	34.6
43	TM34	0	46.6	0.4	0.0	0.0	47.0
43	TM34	1	39.3	2.1	0.0	0.0	41.3
43	TM34	5	37.5	2.2	0.0	0.0	39.8
43	TM34	10	36.9	1.9	0.0	0.1	38.8
43	TM34	50	31.1	4.5	0.0	0.1	35.7
43	TM34	NL	28.5	6.7	0.0	0.1	35.4
44	TM35	0	51.6	0.3	0.0	0.0	51.9
44	TM35	1	40.6	2.7	0.0	0.0	43.3
44	TM35	5	38.2	3.2	0.0	0.1	41.4
44	TM35	10	37.3	2.9	0.0	0.1	40.3
44	TM35	50	31.7	4.3	0.0	0.3	36.3
44	TM35	NL	28.1	7.3	0.0	0.2	35.6

Table B.19: Experiment E: System Average Cost, SCOE ($MWh). INV+F: Invesment + Fixed O&M Costs; VOM: Variable Operations and maintenance costs; DR: Demand response; UR: Unmet Reserves; NE: Network expansion

B.5.4 Exp. E - Prices Distribution

ID	TM	EI	<0	0-5	5-50	50-200	200-1000	>1000	Mean	CoV
35	TM26	0	0.0	99.7	0.0	0.0	0.0	0.3	64.3	19.2
35	TM26	1	0.0	54.7	7.1	36.5	1.5	0.2	42.5	10.1
35	TM26	5	0.0	49.6	37.6	11.8	1.0	0.0	39.8	11.8
35	TM26	10	0.0	50.5	30.3	18.7	0.4	0.0	39.1	12.0

Table B.20 continued from previous page

ID	TM	EI	<0	0-5	5-50	50-200	200-1000	>1000	Mean	CoV
35	TM26	50	0.0	41.9	48.5	9.5	0.1	0.0	34.1	17.6
35	TM26	NL	0.0	19.1	78.9	1.9	0.0	0.0	31.0	18.3
36	TM27	0	0.0	98.8	0.1	0.0	0.1	1.1	43.2	12.7
36	TM27	1	0.0	52.1	40.6	4.4	2.8	0.1	39.5	8.0
36	TM27	5	0.0	51.0	31.2	17.4	0.4	0.1	38.5	7.6
36	TM27	10	0.0	52.6	22.8	24.2	0.4	0.1	38.1	7.6
36	TM27	50	0.0	40.4	52.1	7.4	0.0	0.1	34.9	8.8
36	TM27	NL	0.0	16.8	81.3	1.9	0.0	0.1	31.4	12.5
37	TM28	0	0.0	98.6	0.1	0.0	0.1	1.3	44.7	11.5
37	TM28	1	0.0	55.0	39.1	3.3	2.5	0.1	39.7	7.8
37	TM28	5	0.0	51.8	32.3	15.4	0.5	0.1	38.6	7.5
37	TM28	10	0.1	52.7	22.8	24.0	0.4	0.1	38.1	7.5
37	TM28	50	0.0	40.4	52.1	7.4	0.0	0.1	34.9	8.8
37	TM28	NL	0.0	16.8	81.3	1.9	0.0	0.1	31.4	12.5
38	TM29	0	0.0	98.9	0.1	0.0	0.0	1.1	46.3	14.4
38	TM29	1	0.0	55.9	38.4	3.2	2.5	0.1	39.8	7.8
38	TM29	5	0.0	51.8	32.3	15.4	0.5	0.1	38.6	7.5
38	TM29	10	0.0	52.8	22.8	24.0	0.4	0.1	38.1	7.5
38	TM29	50	0.0	40.4	52.1	7.4	0.0	0.1	34.9	8.8
38	TM29	NL	0.0	16.8	81.3	1.9	0.0	0.1	31.4	12.5
39	TM30	0	0.0	97.0	1.5	0.0	0.2	1.2	40.1	10.9
39	TM30	1	0.0	43.1	43.3	10.5	3.0	0.1	37.4	8.1
39	TM30	5	0.0	44.6	35.6	18.4	1.3	0.1	37.0	7.8
39	TM30	10	0.0	46.0	29.6	23.0	1.4	0.0	36.7	7.3
39	TM30	50	0.0	14.5	81.3	3.9	0.2	0.1	32.8	10.7
39	TM30	NL	0.0	6.2	91.0	2.6	0.1	0.1	31.4	12.6
40	TM31	0	0.0	97.9	1.0	0.0	0.0	1.2	42.6	11.2
40	TM31	1	0.0	47.8	40.6	8.7	2.6	0.3	38.2	7.6
40	TM31	5	0.0	49.9	29.9	19.6	0.4	0.2	37.6	7.4
40	TM31	10	0.0	51.9	22.9	24.7	0.4	0.2	37.2	7.5
40	TM31	50	0.0	24.9	71.0	4.0	0.0	0.1	33.5	10.1
40	TM31	NL	0.0	13.6	84.5	1.8	0.0	0.1	31.4	12.4
41	TM32	0	0.0	97.4	1.0	0.0	0.2	1.4	44.2	10.5
41	TM32	5	0.0	49.0	32.7	17.9	0.3	0.1	38.4	8.2

Table B.20 continued from previous page

ID	TM	EI	<0	0-5	5-50	50-200	200-1000	>1000	Mean	CoV
41	TM32	10	0.0	50.8	24.5	24.4	0.2	0.1	38.0	8.4
41	TM32	50	0.0	39.6	53.0	7.3	0.0	0.1	34.8	8.8
41	TM32	NL	0.0	16.8	81.3	1.9	0.0	0.1	31.4	12.5
42	TM33	0	0.0	98.7	0.0	0.0	0.0	1.3	38.3	13.2
42	TM33	1	0.2	57.8	31.2	7.8	3.0	0.0	36.1	10.9
42	TM33	5	1.1	58.0	13.9	26.6	0.1	0.2	35.3	11.6
42	TM33	10	0.1	60.4	14.3	24.8	0.2	0.2	35.0	11.0
42	TM33	50	0.0	21.0	75.9	2.9	0.0	0.3	32.2	12.0
42	TM33	NL	0.0	9.3	88.1	2.3	0.1	0.2	31.0	11.5
43	TM34	0	0.0	97.7	0.0	0.5	0.0	1.8	41.3	11.2
43	TM34	1	0.1	53.8	36.7	6.5	2.7	0.2	37.3	8.1
43	TM34	5	0.2	53.9	21.9	23.4	0.4	0.2	36.8	8.3
43	TM34	10	0.1	56.4	17.9	25.4	0.2	0.2	36.5	8.3
43	TM34	50	0.0	23.6	72.8	3.6	0.0	0.1	32.9	11.8
43	TM34	NL	0.0	10.4	87.6	1.8	0.0	0.1	31.3	12.9
44	TM35	0	0.0	99.3	0.1	0.0	0.1	0.5	46.5	15.0
44	TM35	1	0.3	51.2	41.3	4.4	2.7	0.1	39.0	7.9
44	TM35	5	0.2	49.6	31.3	18.6	0.3	0.1	38.3	8.5
44	TM35	10	0.0	51.6	23.1	25.1	0.2	0.1	37.8	8.6
44	TM35	50	0.0	35.9	56.6	7.5	0.0	0.1	34.4	9.2
44	TM35	NL	0.0	15.7	82.4	1.9	0.0	0.1	31.3	12.9

Table B.20: Experiment E: Price distributions (%)

B.6 Experiment Group F

B.6.1 Exp. F - Installed Power Capacity

ID	TM	EI	CCGT	OCGT	CCS	Wind	PV	Li	RFB	Ma	Total
45	TM0	0	0	0	0	264	191	87	0	0	543
45	TM0	1	12	2	30	155	143	64	0	0	405
45	TM0	5	16	13	29	121	115	49	0	0	343
45	TM0	10	25	14	21	115	112	45	0	0	332
45	TM0	50	50	18	0	103	98	36	0	0	304
45	TM0	NL	59	21	0	83	80	27	0	0	269
47	TM1	0	0	0	0	268	104	10	87	0	469
47	TM1	1	9	3	22	176	108	13	54	0	385
47	TM1	5	17	12	20	147	99	14	41	0	350
47	TM1	10	25	14	13	139	100	13	38	0	342
47	TM1	50	49	16	0	106	94	18	20	0	303
47	TM1	NL	57	16	0	90	75	12	20	0	270
49	TM2	0	0	0	0	222	129	57	10	31	450
49	TM2	1	7	0	17	165	111	53	2	24	381
49	TM2	5	22	1	12	146	107	52	1	20	361
49	TM2	10	31	0	4	144	108	51	1	20	358
49	TM2	50	47	9	0	109	89	40	0	10	304
49	TM2	NL	53	16	0	94	77	39	0	3	281
46	TM0	0	0	0	0	264	191	87	0	0	543
46	TM0	1	12	2	30	155	143	64	0	0	405
46	TM0	5	16	13	29	121	115	49	0	0	343
46	TM0	10	25	14	21	115	112	45	0	0	332
46	TM0	50	50	18	0	103	98	36	0	0	304
47	TM0	NL	59	21	0	83	80	27	0	0	269
48	TM1	0	0	0	0	268	104	10	87	0	469
48	TM1	1	9	3	22	176	108	13	54	0	385
48	TM1	5	17	12	20	147	99	14	41	0	350
48	TM1	10	25	14	13	139	100	13	38	0	342
48	TM1	50	49	16	0	106	94	18	20	0	303
48	TM1	NL	57	16	0	90	75	12	20	0	270
50	TM2	0	0	0	0	222	129	57	10	31	450

Table B.21 continued from previous page

ID	TM	EI	CCGT	OCGT	CCS	Wind	PV	Li	RFB	Ma	Total
50	TM2	1	7	0	17	165	111	53	2	24	381
50	TM2	5	22	1	12	146	107	52	1	20	361
50	TM2	10	31	0	4	144	108	51	1	20	358
50	TM2	NL	53	16	0	94	77	39	0	3	281

Table B.21: Experiment F: Installed power capacity (GW)

B.6.2 Exp. F - Energy Storage Capacity

ID	TM	EI	Li-ion	RFB	Metal-air	Total
45	TM0	0	916	0	0	916
45	TM0	1	300	0	0	300
45	TM0	5	167	0	0	167
45	TM0	10	144	0	0	144
45	TM0	50	118	0	0	118
45	TM0	NL	89	0	0	89
47	TM1	0	10	2259	0	2270
47	TM1	1	18	800	0	819
47	TM1	5	20	464	0	484
47	TM1	10	19	391	0	410
47	TM1	50	27	136	0	162
47	TM1	NL	19	119	0	138
49	TM2	0	350	155	3522	4027
49	TM2	1	246	28	1707	1982
49	TM2	5	210	8	1126	1343
49	TM2	10	204	7	1106	1317
49	TM2	50	139	0	493	632
49	TM2	NL	138	0	112	250
46	TM0	0	916	0	0	916
46	TM0	1	300	0	0	300
46	TM0	5	167	0	0	167
46	TM0	10	144	0	0	144
46	TM0	50	118	0	0	118
47	TM0	NL	89	0	0	89

Table B.22 continued from previous page

ID	TM	EI	Li-ion	RFB	Metal-air	Total
48	TM1	0	10	2259	0	2270
48	TM1	1	18	800	0	819
48	TM1	5	20	464	0	484
48	TM1	10	19	391	0	410
48	TM1	50	27	136	0	162
48	TM1	NL	19	119	0	138
50	TM2	0	350	155	3522	4027
50	TM2	1	246	28	1707	1982
50	TM2	5	210	8	1126	1343
50	TM2	10	204	7	1106	1317
50	TM2	NL	138	0	112	250

Table B.22: Experiment F: Installed Storage Capacity (GWh)

B.6.3 Exp. F - SCOE

ID	TM	EI	INV+F	VOM	DR	SUP	Total
45	TM0	0	69.0	0.1	0.0	0.0	69.0
45	TM0	1	48.6	1.1	0.0	0.1	49.8
45	TM0	5	40.2	3.4	0.0	0.3	43.9
45	TM0	10	38.0	3.8	0.0	0.3	42.2
45	TM0	50	32.4	4.2	0.0	0.3	37.0
45	TM0	NL	28.6	7.3	0.0	0.3	36.2
47	TM1	0	55.8	0.3	0.0	0.0	56.1
47	TM1	1	44.7	1.1	0.0	0.1	45.9
47	TM1	5	39.5	2.7	0.0	0.2	42.4
47	TM1	10	37.9	2.8	0.0	0.2	41.0
47	TM1	50	31.8	4.3	0.0	0.3	36.4
47	TM1	NL	28.1	7.3	0.0	0.2	35.6
49	TM2	0	48.1	0.2	0.0	0.0	48.3
49	TM2	1	41.3	1.2	0.0	0.1	42.6
49	TM2	5	38.1	2.0	0.0	0.1	40.2
49	TM2	10	37.1	1.7	0.0	0.1	38.9
49	TM2	50	30.8	4.4	0.0	0.2	35.3

Table B.23 continued from previous page

ID	TM	EI	INV+F	VOM	DR	SUP	Total
49	TM2	NL	28.0	6.8	0.0	0.2	35.0
46	TM0	0	69.0	0.1	0.0	0.0	69.0
46	TM0	1	48.6	1.1	0.0	0.1	49.8
46	TM0	5	40.2	3.4	0.0	0.3	43.9
46	TM0	10	38.0	3.8	0.0	0.3	42.2
46	TM0	50	32.4	4.2	0.0	0.3	37.0
47	TM0	NL	28.6	7.3	0.0	0.3	36.2
48	TM1	0	55.8	0.3	0.0	0.0	56.1
48	TM1	1	44.7	1.1	0.0	0.1	45.9
48	TM1	5	39.5	2.7	0.0	0.2	42.4
48	TM1	10	37.9	2.8	0.0	0.2	41.0
48	TM1	50	31.8	4.3	0.0	0.3	36.4
48	TM1	NL	28.1	7.3	0.0	0.2	35.6
50	TM2	0	48.1	0.2	0.0	0.0	48.3
50	TM2	1	41.3	1.2	0.0	0.1	42.6
50	TM2	5	38.1	2.0	0.0	0.1	40.2
50	TM2	10	37.1	1.7	0.0	0.1	38.9
50	TM2	NL	28.0	6.8	0.0	0.2	35.0

Table B.23: Experiment F: System Average Cost, SCOE ($MWhs). INV+F: Invesment + Fixed O&M Costs; VOM: Variable Operations and maintenance costs; DR: Demand response; UR: Unmet Reserves; NE: Network expansion

B.6.4 Exp. F - Prices Distribution

ID	TM	EI	<0	0-5	5-50	50-200	200-1000	>1000	Mean	CoV
45	TM0	0	0.00	99.69	0.00	0.00	0.00	0.31	64.27	19.21
45	TM0	1	0.00	84.71	0.01	3.40	11.13	0.75	49.81	7.06
45	TM0	5	0.00	61.80	2.45	30.09	5.60	0.07	42.06	9.81
45	TM0	10	0.00	57.25	8.02	34.38	0.32	0.03	40.48	10.94
45	TM0	50	0.00	41.89	48.54	9.47	0.09	0.01	34.14	17.67
45	TM0	NL	0.03	19.44	78.67	1.85	0.00	0.01	30.91	21.38
47	TM1	0	0.00	99.06	0.00	0.00	0.42	0.52	47.61	20.46

Table B.24 continued from previous page

ID	TM	EI	<0	0-5	5-50	50-200	200-1000	>1000	Mean	CoV
47	TM1	1	0.00	81.60	0.00	16.45	1.71	0.25	42.71	7.65
47	TM1	5	0.00	62.84	7.71	27.82	1.56	0.07	39.70	7.39
47	TM1	10	0.00	60.34	12.91	26.20	0.48	0.07	38.77	7.47
47	TM1	50	0.00	40.40	52.06	7.44	0.03	0.07	34.86	8.80
47	TM1	NL	0.00	16.76	81.25	1.94	0.00	0.05	31.35	12.54
49	TM2	0	0.00	97.80	0.96	0.00	0.06	1.17	42.45	10.34
49	TM2	1	0.02	68.08	11.69	17.54	2.33	0.34	39.98	5.78
49	TM2	5	0.00	58.67	13.93	26.62	0.63	0.16	37.91	6.99
49	TM2	10	0.00	57.91	15.47	25.92	0.53	0.16	37.35	7.48
49	TM2	50	0.00	25.27	71.94	2.70	0.00	0.09	32.87	10.38
49	TM2	NL	0.03	14.23	84.44	1.21	0.03	0.05	31.26	12.66
46	TM0	0	0.00	99.69	0.00	0.00	0.00	0.31	64.27	19.21
46	TM0	1	0.00	84.71	0.01	3.40	11.13	0.75	49.81	7.06
46	TM0	5	0.00	61.80	2.45	30.09	5.60	0.07	42.06	9.81
46	TM0	10	0.00	57.25	8.02	34.38	0.32	0.03	40.48	10.94
46	TM0	50	0.00	41.89	48.54	9.47	0.09	0.01	34.14	17.67
47	TM0	NL	0.04	19.43	78.67	1.85	0.00	0.01	30.91	21.38
48	TM1	0	0.00	99.06	0.00	0.00	0.42	0.52	47.61	20.46
48	TM1	1	0.00	81.60	0.00	16.45	1.71	0.25	42.71	7.65
48	TM1	5	0.00	62.84	7.71	27.82	1.56	0.07	39.70	7.39
48	TM1	10	0.00	60.34	12.91	26.20	0.48	0.07	38.77	7.47
48	TM1	50	0.00	40.40	52.06	7.44	0.03	0.07	34.86	8.80
48	TM1	NL	0.00	16.76	81.25	1.94	0.00	0.05	31.35	12.54
50	TM2	0	0.03	97.77	0.96	0.00	0.06	1.17	42.45	10.34
50	TM2	1	0.02	68.08	11.69	17.54	2.33	0.34	39.98	5.78
50	TM2	5	0.00	58.67	13.93	26.62	0.63	0.16	37.91	6.99
50	TM2	10	0.00	57.91	15.47	25.92	0.53	0.16	37.35	7.48
50	TM2	NL	0.03	14.23	84.44	1.21	0.03	0.05	31.26	12.66

Table B.24: Experiment F: Price distributions (%)

B.7 Experiment Group I

B.7.1 Exp. I - Installed Power Capacity

ID	TM	EI	CCGT	OCGT	CCS	Wind	PV	Li	RFB	Th	Total
61	TM0	0	0	0	0	183	216.035	77.5	0	0	476
61	TM0	1	5.42	0	29.30656	141	152.997	63.8	0	0	392
61	TM0	5	15.8	5.85	29.80518	115	119.681	48.2	0	0	335
61	TM0	10	25.1	7.76	21.53459	112	114.26	44.5	0	0	326
61	TM0	50	51.1	9.61	0	102	99.2526	34.6	0	0	296
61	TM0	NL	59.3	11.3	0	78.3	82.6561	28.6	0	0	260
62	TM1	0	0	0	0	127	239.034	8.75	74	0	449
62	TM1	1	6.66	0	23.83412	112	170.457	14.6	51	0	378
62	TM1	5	17.3	4.79	20.28811	101	144.156	15.3	40	0	343
62	TM1	10	25.5	6.4	13.09	101	138.336	14.7	37	0	337
62	TM1	50	48.6	9.82	0	93.3	107.287	15.4	22	0	296
62	TM1	NL	58.4	9.96	0	76.7	84.2487	14.4	16	0	260
63	TM2	0	0	0	0	101	254.953	4.21	44	37.851	442
63	TM2	1	6.11	0	14.99261	101	175.928	15.3	25	30.856	369
63	TM2	5	21.1	0.03	9.14459	99.6	157.526	15.9	22	24.292	349
63	TM2	10	28.4	0.45	2.855542	101	154.853	15.9	21	23.503	348
63	TM2	50	47	4.83	0	88.7	107.515	17.1	12	13.553	290
63	TM2	NL	56	6.67	0	76.9	91.1094	15.8	10	8.782	266

Table B.25: Experiment I: Installed power capacity (GW)

B.7.2 Exp. I - Energy Storage Capacity

ID	TM	EI	Li-ion	RFB	Thermal	Total
61	TM0	0	741	0	0	741.1
61	TM0	1	310	0	0	310.5
61	TM0	5	159	0	0	158.7
61	TM0	10	136	0	0	135.8
61	TM0	50	91.1	0	0	91.13
61	TM0	NL	79	0	0	78.96
62	TM1	0	12.1	1444	0	1456

Table B.26 continued from previous page

ID	TM	EI	Li-ion	RFB	Thermal	Total
62	TM1	1	21	694.5	0	715.4
62	TM1	5	22.7	416.7	0	439.4
62	TM1	10	21.7	356.4	0	378.2
62	TM1	50	24.9	145.4	0	170.3
62	TM1	NL	24.2	87.17	0	111.4
63	TM2	0	4.22	359.4	2674.3	3038
63	TM2	1	23.2	180.4	2098.6	2302
63	TM2	5	25.2	149.8	1368.9	1544
63	TM2	10	25.8	136.5	1211.2	1374
63	TM2	50	29.4	63.74	550.28	643.4
63	TM2	NL	28.2	51.79	228.67	308.6

Table B.26: Experiment I: Installed Storage Capacity (GWh)

B.7.3 Exp. I - SCOE

ID	TM	EI	INV+F	VOM	DR	SUP	Total
61	TM0	0	60.12	0.08	3.39	0	63.6
61	TM0	1	47.4	1.11	0.59	0.11	49.21
61	TM0	5	39.46	3.45	0.3	0.29	43.5
61	TM0	10	37.42	3.81	0.22	0.34	41.79
61	TM0	50	31.65	4.2	0.25	0.35	36.46
61	TM0	NL	27.39	7.58	0.22	0.33	35.52
62	TM1	0	51.55	0.18	1.74	0	53.47
62	TM1	1	44.01	1.17	0.31	0.1	45.59
62	TM1	5	38.78	2.71	0.33	0.2	42.02
62	TM1	10	37.25	2.84	0.29	0.21	40.6
62	TM1	50	31.29	4.26	0.2	0.27	36.03
62	TM1	NL	27.17	7.57	0.25	0.26	35.25
63	TM2	0	46.11	0.31	0.55	0	46.97
63	TM2	1	40.92	1.11	0.08	0.08	42.19
63	TM2	5	37.89	1.89	0.12	0.11	40
63	TM2	10	36.99	1.59	0.12	0.12	38.83
63	TM2	50	30.63	4.44	0.19	0.17	35.43

Table B.27 continued from previous page

ID	TM	EI	INV+F	VOM	DR	SUP	Total
63	TM2	NL	27.7	6.95	0.24	0.17	35.05

Table B.27: Experiment I: System Average Cost, SCOE ($MWh). INV+F: Invesment + Fixed O&M Costs; VOM: Variable Operations and maintenance costs; DR: Demand response; UR: Unmet Reserves; NE: Network expansion

B.7.4 Exp. I - Prices Distribution

ID	TM	EI	<0	0-5	5-50	50-200	200-1000	>1000	Mean	CoV
61	TM0	0	0	98.86	0	0	0	1.138	62.26	11.06
61	TM0	1	0	83.81	0	7.4861	7.910102	0.789	50.03	5.311
61	TM0	5	0	61.59	2.698	29.995	5.460417	0.259	42.16	4.227
61	TM0	10	0	57.38	7.758	34.322	0.280523	0.263	40.46	4.04
61	TM0	50	0	43.01	41.9	14.768	0.05219	0.272	35.44	4.252
61	TM0	NL	0.02	19.1	79.07	1.5494	0	0.259	31.19	4.923
62	TM1	0	0	98.41	0	0.0016	0.383273	1.207	47.46	9.646
62	TM1	1	0	81.64	0.002	16.42	1.516782	0.418	43.05	5.317
62	TM1	5	0	62.82	7.763	27.827	1.332485	0.258	39.64	4.359
62	TM1	10	0	60.37	12.64	26.332	0.399582	0.261	38.69	4.277
62	TM1	50	0	40.08	53.39	6.1992	0.061976	0.269	34.64	4.569
62	TM1	NL	0	16.55	81.64	1.551	0.006524	0.261	31.46	4.811
63	TM2	0	0	97.52	0.091	0.0114	0.490916	1.885	41.39	7.145
63	TM2	1	0.23	74.42	5.48	17.363	1.947353	0.561	38.8	4.033
63	TM2	5	0.26	60.76	10.51	27.449	0.631177	0.395	37.25	3.714
63	TM2	10	0.1	61.4	13.11	24.67	0.353916	0.373	36.77	3.73
63	TM2	50	0	25.9	69.84	3.9061	0.026095	0.326	33.08	4.259
63	TM2	NL	0	10.44	87.41	1.8479	0.001631	0.307	31.34	4.568

Table B.28: Experiment I: Price distributions (%)

Appendix C

Results by Policy scenario

This appendix presents the overall results by metric of interest, by experiment group and by emission policy. A summary statistic table is included for each of the metrics, that take into account the whole set of experiments performed.

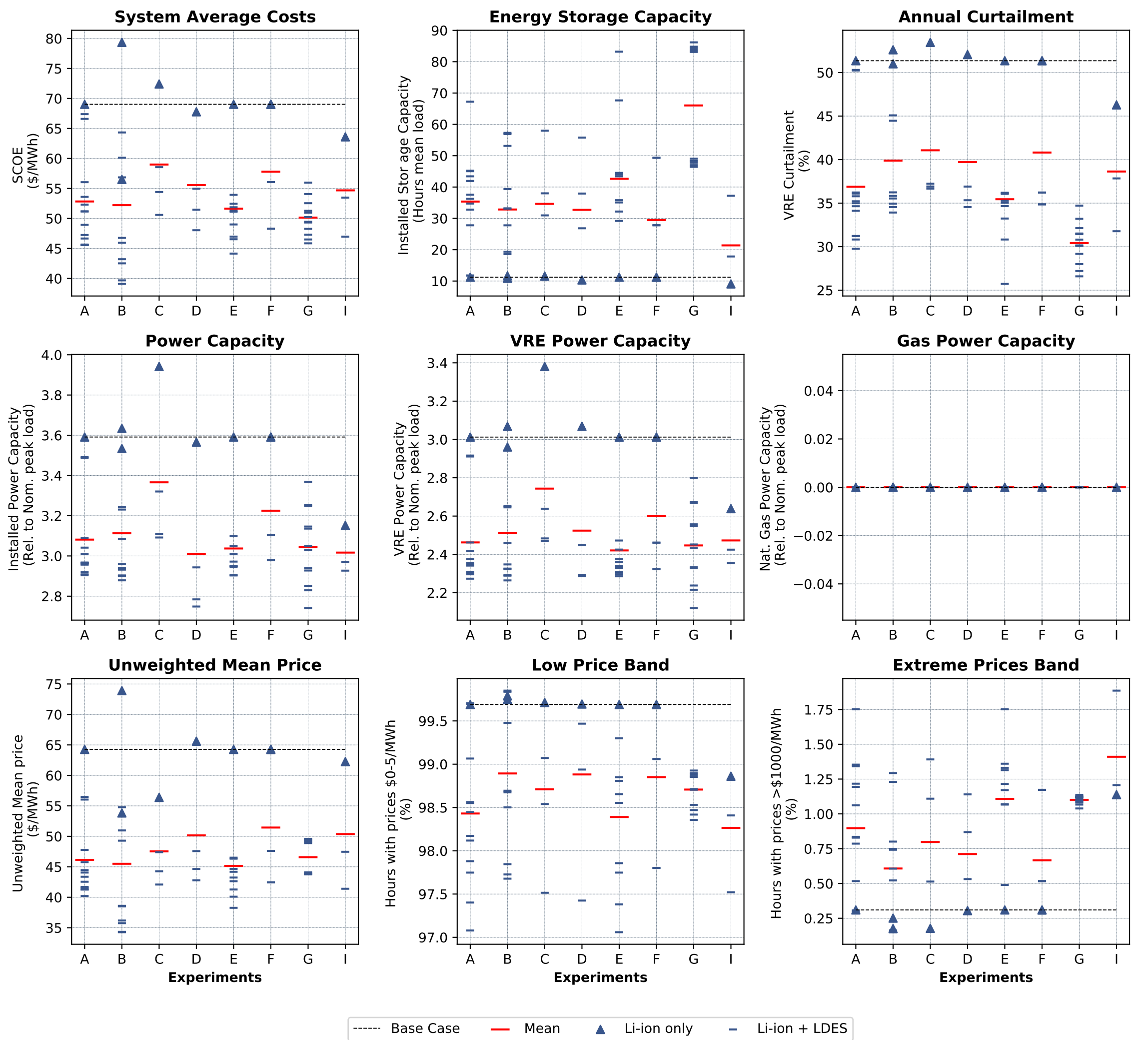

Figure C-1: Results overview of the $0gCO_2/kWh$ case, showing the magnitude of the main metrics by experiment group.

	mean	std	min	25%	50%	75%	max	CoV
System Average Costs ($/MWh)	53.1	8.4	39.1	47.0	51.2	56.1	79.3	0.2
Power Capacity (Rel. to Nom. peak load)	3.1	0.3	2.7	2.9	3.0	3.2	3.9	0.1
Energy Storage Capacity (Hours mean load)	40.3	21.3	9.1	27.8	38.0	49.0	86.2	0.5
VRE Power Capacity (Rel. to Nom. peak load)	2.5	0.3	2.1	2.3	2.4	2.6	3.4	0.1
Gas Power Capacity (Rel. to Nom. peak load)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Annual Curtailment (%)	36.9	7.3	25.7	31.8	35.0	36.9	53.5	0.2
Price Volatility (-)	14.8	4.6	7.1	11.1	13.0	19.2	27.4	0.3
Unweighted Mean Price ($/MWh)	47.0	8.2	34.3	42.1	44.3	49.3	73.9	0.2
Extreme Prices Band (%)	0.9	0.4	0.2	0.5	1.1	1.2	1.9	0.5
Low Price Band (%)	98.6	0.8	97.1	98.1	98.7	99.1	99.8	0.0

Table C.1: Summary statistics for overall results, taking into account all experiment results for the 0g case.

	mean	std	min	25%	50%	75%	max	CoV
System Average Costs ($/MWh)	44.3	4.2	34.8	41.8	43.9	45.9	56.6	0.1
Power Capacity (Rel. to Nom. peak load)	2.5	0.2	2.2	2.5	2.5	2.6	2.9	0.1
Energy Storage Capacity (Hours mean load)	18.3	12.6	1.9	8.9	17.3	24.3	48.7	0.7
VRE Power Capacity (Rel. to Nom. peak load)	1.9	0.1	1.5	1.8	1.9	2.0	2.3	0.1
Gas Power Capacity (Rel. to Nom. peak load)	0.2	0.1	0.1	0.2	0.2	0.2	0.3	0.3
Annual Curtailment (%)	18.9	6.3	9.2	14.1	17.5	22.8	31.9	0.3
Price Volatility (-)	8.5	2.5	4.0	6.9	7.8	10.0	14.0	0.3
Unweighted Mean Price ($/MWh)	41.9	4.9	32.2	38.9	41.8	44.3	56.6	0.1
Extreme Prices Band (%)	0.3	0.2	0.0	0.1	0.2	0.4	0.8	0.8
Low Price Band (%)	73.5	10.8	43.2	68.1	76.5	81.6	85.9	0.1

Table C.2: Summary statistics for overall results, taking into account all experiment results for the 1g case.

	mean	std	min	25%	50%	75%	max	CoV
System Average Costs ($/MWh)	41.1	3.2	32.8	39.9	41.4	42.5	49.2	0.1
Power Capacity (Rel. to Nom. peak load)	2.3	0.1	2.1	2.2	2.3	2.4	2.7	0.1
Energy Storage Capacity (Hours mean load)	11.6	9.0	1.3	5.3	7.6	17.4	38.8	0.8
VRE Power Capacity (Rel. to Nom. peak load)	1.7	0.1	1.4	1.6	1.7	1.7	2.1	0.1
Gas Power Capacity (Rel. to Nom. peak load)	0.3	0.1	0.1	0.2	0.3	0.3	0.4	0.3
Annual Curtailment (%)	13.8	3.3	7.8	11.4	13.4	15.7	22.3	0.2
Price Volatility (-)	8.8	2.7	3.7	7.4	7.7	9.8	14.8	0.3
Unweighted Mean Price ($/MWh)	38.9	3.2	31.1	37.4	39.6	40.8	47.2	0.1
Extreme Prices Band (%)	0.1	0.1	0.0	0.1	0.1	0.1	0.4	0.8
Low Price Band (%)	59.8	6.9	44.6	55.4	60.3	62.8	75.2	0.1

Table C.3: Summary statistics for overall results, taking into account all experiment results for the 5g case.

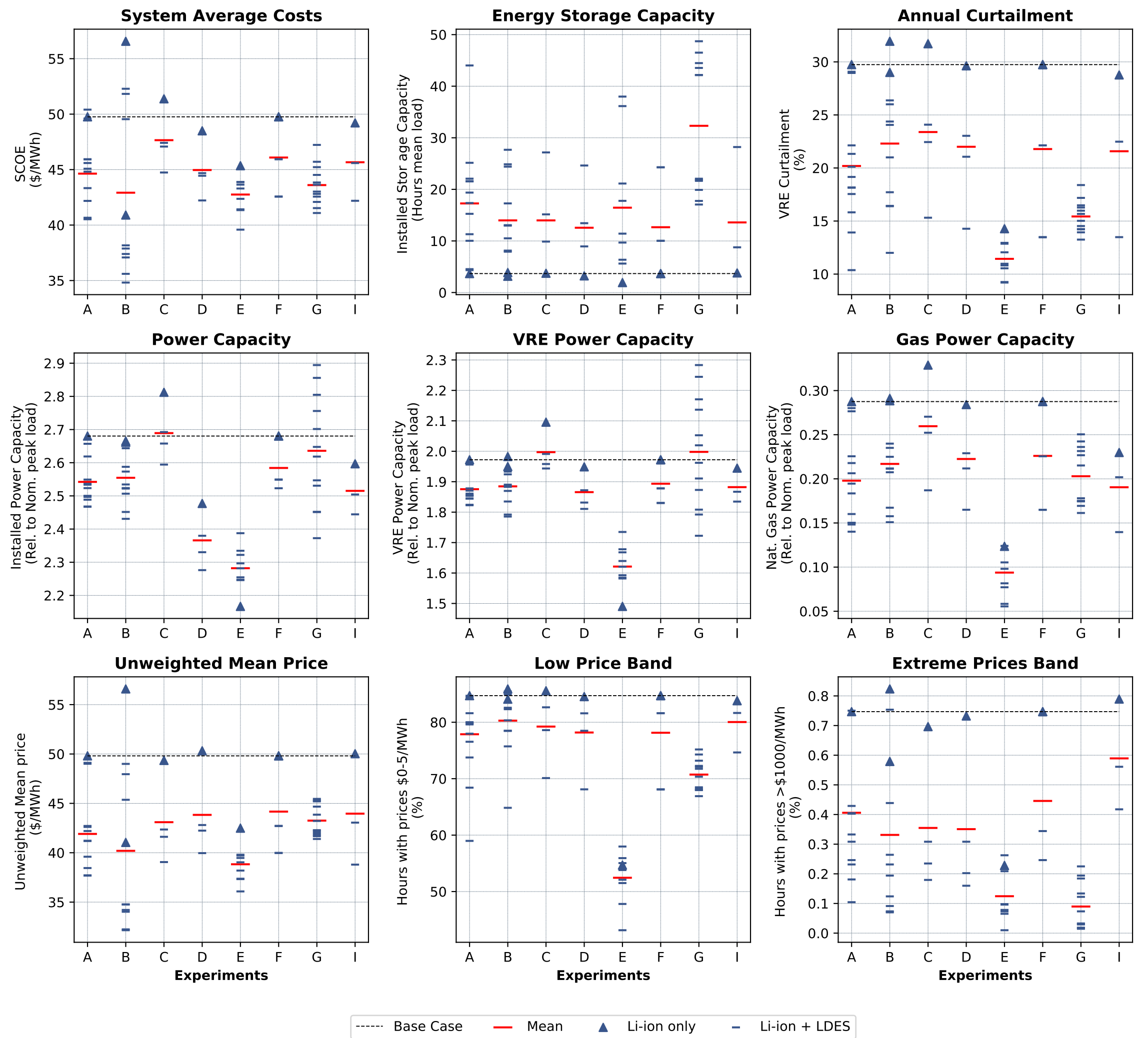

Figure C-2: Results overview of the $1gCO_2/kWh$ case, showing the magnitude of the main metrics by experiment group. By each experiment group, the scenario that contains Li-ion as the single storage technology is highlighted.

	mean	std	min	25%	50%	75%	max	CoV
System Average Costs ($/MWh)	39.8	3.1	31.5	38.7	40.3	41.0	47.2	0.1
Power Capacity (Rel. to Nom. peak load)	2.3	0.1	2.0	2.2	2.3	2.4	2.7	0.1
Energy Storage Capacity (Hours mean load)	10.3	8.6	0.9	4.2	7.0	16.1	39.7	0.8
VRE Power Capacity (Rel. to Nom. peak load)	1.6	0.1	1.4	1.5	1.6	1.7	2.1	0.1
Gas Power Capacity (Rel. to Nom. peak load)	0.3	0.1	0.2	0.2	0.3	0.3	0.5	0.2
Annual Curtailment (%)	13.4	3.0	8.0	11.3	12.8	15.1	21.5	0.2
Price Volatility (-)	9.0	2.8	3.7	7.5	8.3	10.9	15.2	0.3
Unweighted Mean Price ($/MWh)	38.1	3.0	30.2	36.9	38.7	40.1	44.9	0.1
Extreme Prices Band (%)	0.1	0.1	0.0	0.0	0.1	0.1	0.4	0.8
Low Price Band (%)	58.1	6.3	45.0	53.9	57.4	60.4	74.2	0.1

Table C.4: Summary statistics for overall results, taking into account all experiment results for the 10g case.

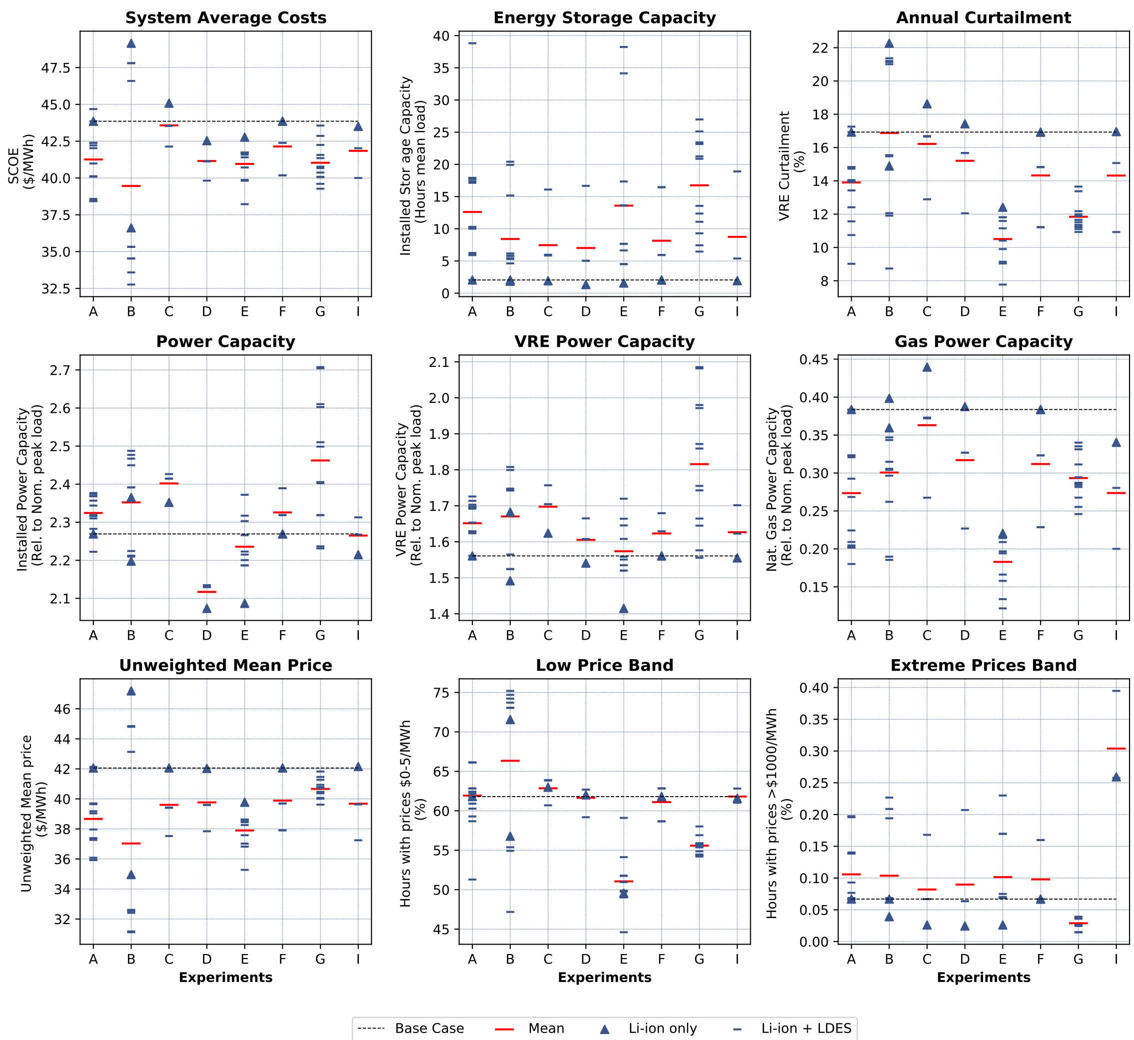

Figure C-3: Results overview of the $5gCO_2/kWh$ case, showing the magnitude of the main metrics by experiment group. By each experiment group, the scenario that contains Li-ion as the single storage technology is highlighted.

	mean	std	min	25%	50%	75%	max	CoV
System Average Costs ($/MWh)	35.7	2.3	29.7	35.3	36.0	36.4	41.6	0.1
Power Capacity (Rel. to Nom. peak load)	2.0	0.1	1.8	2.0	2.0	2.0	2.4	0.1
Energy Storage Capacity (Hours mean load)	4.4	4.4	0.3	1.6	2.1	7.2	23.0	1.0
VRE Power Capacity (Rel. to Nom. peak load)	1.4	0.1	1.3	1.3	1.3	1.3	1.7	0.1
Gas Power Capacity (Rel. to Nom. peak load)	0.4	0.0	0.3	0.4	0.4	0.4	0.5	0.1
Annual Curtailment (%)	7.4	2.5	2.3	5.5	8.4	9.6	11.8	0.3
Price Volatility (-)	12.1	4.0	4.3	8.8	11.6	15.2	22.1	0.3
Unweighted Mean Price ($/MWh)	33.6	3.1	25.6	32.9	34.4	34.9	40.5	0.1
Extreme Prices Band (%)	0.1	0.1	0.0	0.0	0.1	0.1	0.3	0.8
Low Price Band (%)	35.6	7.8	14.5	29.5	39.6	41.8	45.6	0.2

Table C.5: Summary statistics for overall results, taking into account all experiment results for the 50g case.

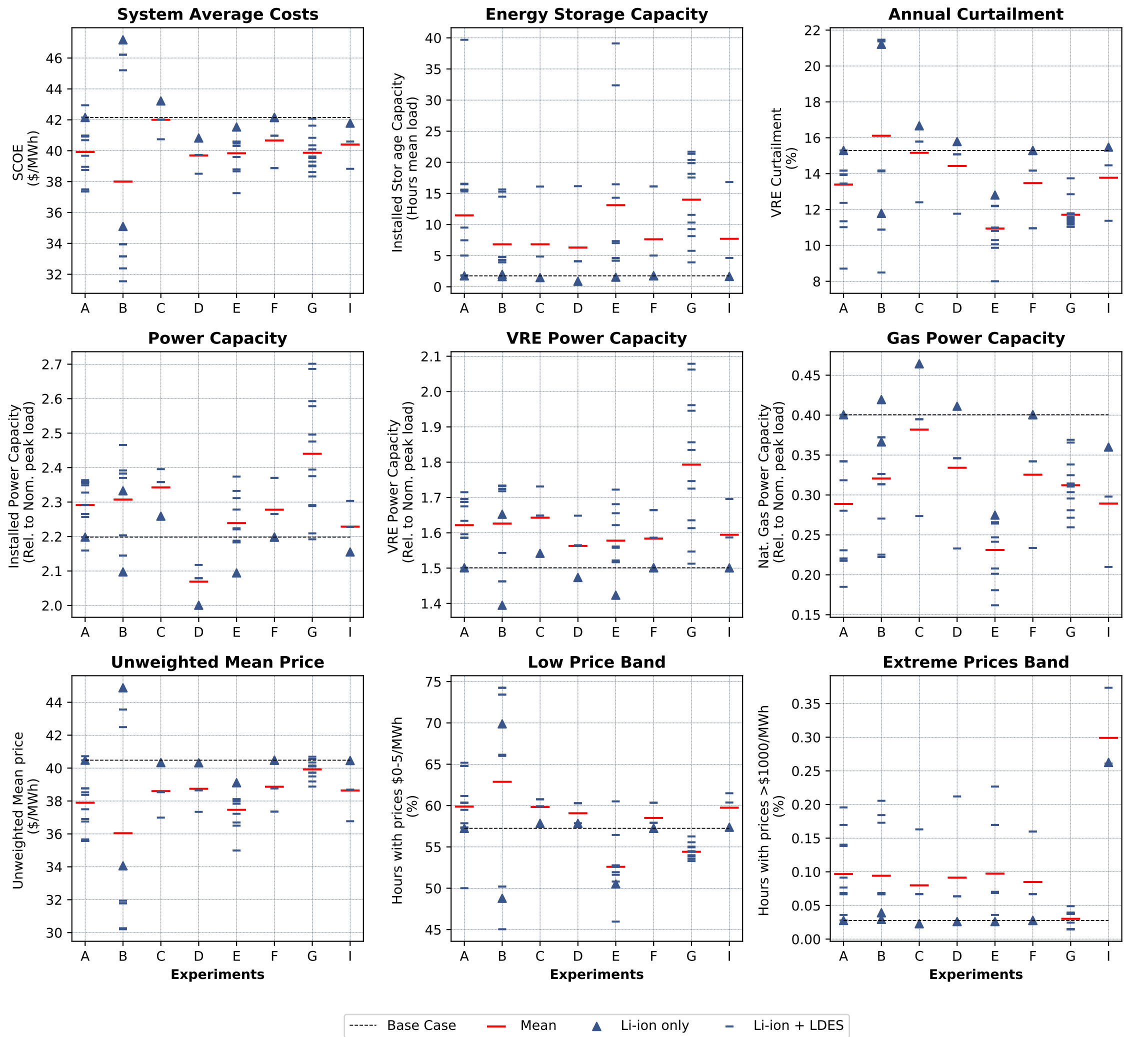

Figure C-4: Results overview of the 10gCO_2/kWh case, showing the magnitude of the main metrics by experiment group. By each experiment group, the scenario that contains Li-ion as the single storage technology is highlighted.

	mean	std	min	25%	50%	75%	max	CoV
System Average Costs ($/MWh)	35.1	2.0	29.7	35.0	35.5	35.7	39.5	0.1
Power Capacity (Rel. to Nom. peak load)	1.8	0.1	1.5	1.8	1.8	1.9	2.2	0.1
Energy Storage Capacity (Hours mean load)	3.0	3.4	0.0	1.4	1.7	3.8	20.2	1.1
VRE Power Capacity (Rel. to Nom. peak load)	1.1	0.1	0.8	1.1	1.1	1.2	1.5	0.1
Gas Power Capacity (Rel. to Nom. peak load)	0.5	0.1	0.3	0.4	0.5	0.5	0.6	0.1
Annual Curtailment (%)	3.1	1.8	0.4	2.5	2.9	3.4	8.7	0.6
Price Volatility (-)	13.6	3.7	4.6	12.5	12.9	15.6	22.8	0.3
Unweighted Mean Price ($/MWh)	31.0	2.0	25.5	31.2	31.4	31.5	34.3	0.1
Extreme Prices Band (%)	0.1	0.1	0.0	0.1	0.1	0.1	0.3	0.8
Low Price Band (%)	17.6	7.7	4.1	14.3	16.8	19.2	39.6	0.4

Table C.6: Summary statistics for overall results, taking into account all experiment results for the No Limits case.

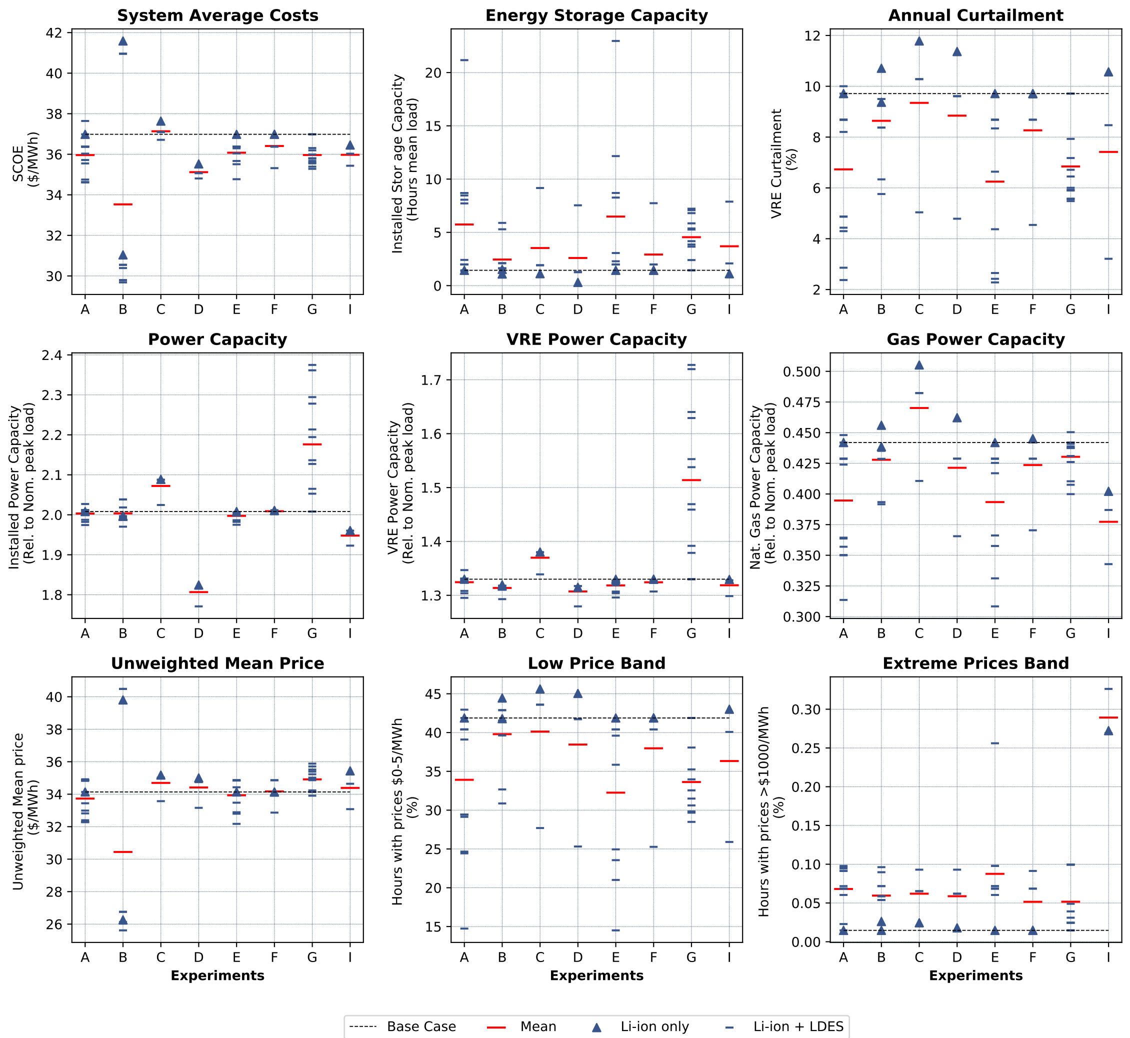

Figure C-5: Results overview of the $50gCO_2/kWh$ case, showing the magnitude of the main metrics by experiment group. By each experiment group, the scenario that contains Li-ion as the single storage technology is highlighted.

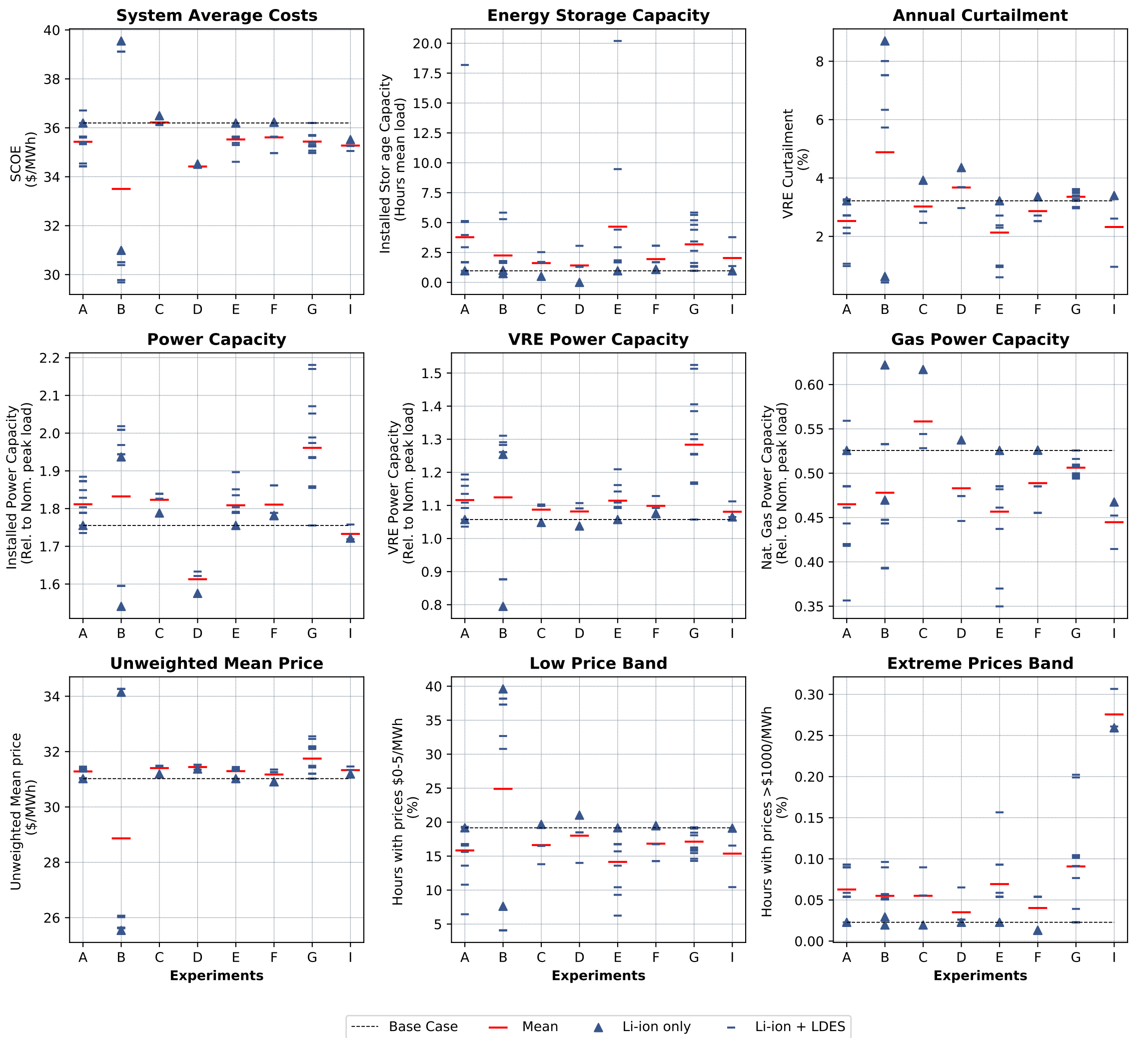

Figure C-6: Results overview of the No Limits case, showing the magnitude of the main metrics by experiment group. By each experiment group, the scenario that contains Li-ion as the single storage technology is highlighted.

Appendix D

Effects analysis

This appendix presents the summary of the effects' analysis for each of the CO_2 emission intensity constraints.

	SCOE	GenCapPeak	StorCapHours	VRE_Cap	Gas_Cap	Curtailment	CoV	MeanPrice	ExtrPriceBand	ZeroPriceBand
RFB (M)	-18.3	-12.6	121.3	-16.3	0.0	-24.6	-3.0	-26.6	53.3	-0.3
H2 (M)	-6.9	-6.4	45.9	-8.0	0.0	-9.7	-40.3	-6.7	247.8	-0.9
Metal-air (M)	-13.2	-6.4	114.1	-7.8	0.0	-9.6	-42.4	-10.7	221.8	-1.7
Allam	0.1	-0.1	2.0	-0.1	0.0	-0.1	0.3	0.2	4.7	0.1
LI-ion-low	-1.6	-0.4	1.4	-0.7	0.0	-0.2	-3.9	-0.4	-5.5	-0.1
LDES-low	-4.7	-1.7	29.5	-2.3	0.0	-4.4	-6.1	-4.4	7.2	-0.5
LDES-high	7.2	3.9	-22.8	5.4	0.0	11.7	9.7	7.1	-22.3	0.1
VRE-low	-17.8	1.2	-5.2	2.0	0.0	6.7	28.4	-18.4	-48.1	0.3
VRE-high	15.2	-1.7	10.7	-2.0	0.0	-1.4	-4.1	15.0	-4.9	0.1
H2_ind	-13.7	3.4	139.1	6.0	0.0	-19.9	-29.1	-2.8	117.4	-0.4
DemFlex	-1.8	-4.7	5.3	-0.9	0.0	0.6	3.2	0.7	-9.8	0.1
DemResp	-4.3	-6.3	-23.1	-4.9	0.0	-0.8	-43.2	-1.4	136.1	-0.6

Table D.1: Results of the effects' analysis at $0gCO_2/kWh$ emission intensity, showing the average impact (change in %) of each factor on the key metrics.

	SCOE	GenCapPeak	StorCapHours	VRE_Cap	Gas_Cap	Curtailment	CoV	MeanPrice	ExtrPriceBand	ZeroPriceBand
RFB (M)	-7.3	-4.7	167.3	-4.4	-20.9	-23.5	-4.8	-14.3	-40.6	-2.9
H2 (M)	-0.8	-2.0	58.7	-2.2	-8.7	-11.2	1.9	-1.6	-45.5	-4.5
Metal-air (M)	-5.9	-2.4	173.4	-2.3	-30.2	-39.3	-1.7	-7.4	35.5	-14.5
Allam	-4.0	-10.5	-40.0	-14.4	-49.5	-33.0	12.5	-6.3	-54.8	-30.6
LI-ion-low	-2.1	1.9	-1.2	-0.3	2.9	0.0	-3.8	-0.1	-19.1	-0.3
LDES-low	-3.6	-0.3	83.1	-0.2	-19.4	-14.4	0.4	-4.0	-5.3	-6.6
LDES-high	3.0	1.5	-31.3	1.5	11.8	12.8	-1.4	5.0	54.7	3.9
VRE-low	-17.4	0.6	-12.3	1.9	0.1	16.0	44.0	-18.5	-29.9	6.7
VRE-high	13.9	-1.6	8.4	-2.4	1.8	-8.3	-7.8	14.1	60.8	-2.6
H2_ind	-8.0	9.1	220.2	14.7	-8.7	-31.8	73.0	0.1	-69.2	-13.9
DemFlex	-2.6	-7.4	-9.2	-1.0	1.5	2.7	-3.8	0.6	-9.7	0.0
DemResp	-0.9	-2.4	-4.5	-1.0	-15.3	-0.8	-27.7	0.6	37.6	-0.5

Table D.2: Results of the effects' analysis at $1gCO_2/kWh$ emission intensity, showing the average impact (change in %) of each factor on the key metrics.

	SCOE	GenCapPeak	StorCapHours	VRE_Cap	Gas_Cap	Curtailment	CoV	MeanPrice	ExtrPriceBand	ZeroPriceBand
RFB (M)	-3.2	1.3	179.0	3.4	-14.6	-12.1	-15.3	-5.8	25.0	1.4
H2 (M)	-0.0	-0.1	9.9	0.0	-1.6	-0.9	0.1	-0.1	0.0	-0.7
Metal-air (M)	-3.6	1.4	218.3	3.4	-31.5	-25.4	3.9	-4.2	212.2	-7.8
Allam	-1.3	-4.7	-22.3	-6.1	-31.0	-18.4	7.9	-2.3	-11.6	-16.5
LI-ion-low	-2.3	2.8	-7.2	0.0	2.6	0.3	-5.7	-0.3	-3.9	-0.9
LDES-low	-1.9	0.5	94.0	1.3	-11.7	-9.1	3.9	-1.9	-12.2	-4.3
LDES-high	1.5	-0.9	-27.6	-1.6	9.8	5.5	9.4	2.2	-13.1	-0.5
VRE-low	-17.0	3.8	2.0	7.2	-9.1	37.9	28.5	-17.6	-7.5	19.6
VRE-high	12.8	-4.4	-9.1	-6.2	8.8	-18.6	-16.0	13.0	4.0	-13.1
H2_ind	-5.7	12.4	199.6	21.3	-15.0	-23.2	97.2	1.7	-61.0	-11.5
DemFlex	-2.9	-8.4	-18.1	-1.4	1.3	4.8	1.8	-0.2	-16.8	0.1
DemResp	-0.7	-2.2	-2.9	-0.3	-9.6	1.2	-49.9	0.0	224.4	-0.1

Table D.3: Results of the effects' analysis at 5gCO_2/kWh emission intensity, showing the average impact (change in %) of each factor on the key metrics.

	SCOE	GenCapPeak	StorCapHours	VRE_Cap	Gas_Cap	Curtailment	CoV	MeanPrice	ExtrPriceBand	ZeroPriceBand
RFB (M)	-2.7	2.5	162.5	5.1	-13.4	-4.8	-27.3	-4.5	114.7	4.8
H2 (M)	-0.0	-0.0	-0.0	-0.0	0.0	0.0	0.0	0.0	0.0	0.0
Metal-air (M)	-3.3	1.7	230.4	3.5	-29.7	-25.2	-0.1	-3.7	183.7	-8.5
Allam	-0.7	-3.1	-17.3	-4.0	-17.0	-12.1	4.8	-1.5	-5.4	-11.2
LI-ion-low	-2.4	2.6	-12.5	-0.2	3.2	0.1	-3.3	-0.3	-5.0	-0.7
LDES-low	-1.8	0.9	88.1	1.7	-10.0	-7.6	1.7	-1.6	-17.8	-3.5
LDES-high	1.4	-1.1	-26.9	-2.0	9.6	4.2	13.9	1.7	-28.0	-1.5
VRE-low	-17.4	4.6	-0.3	7.9	-7.2	41.3	23.8	-17.6	12.8	20.6
VRE-high	12.9	-5.1	-11.8	-7.6	9.9	-23.6	-11.5	12.2	-1.4	-17.6
H2_ind	-4.9	14.1	205.7	23.2	-14.9	-20.5	99.8	2.3	-78.0	-9.7
DemFlex	-3.0	-8.6	-22.1	-1.5	1.5	4.9	-0.8	-0.4	-1.8	0.2
DemResp	-0.7	-1.9	-3.7	0.0	-8.9	2.2	-52.9	-0.1	419.2	0.3

Table D.4: Results of the effects' analysis at 10gCO_2/kWh emission intensity, showing the average impact (change in %) of each factor on the key metrics.

	SCOE	GenCapPeak	StorCapHours	VRE_Cap	Gas_Cap	Curtailment	CoV	MeanPrice	ExtrPriceBand	ZeroPriceBand
RFB (M)	-1.6	-0.1	41.5	-0.2	-3.3	-10.8	-47.1	1.9	293.5	-4.1
H2 (M)	0.0	-0.0	0.0	-0.0	0.0	-0.0	0.0	0.0	0.0	-0.0
Metal-air (M)	-0.7	-1.2	295.1	-1.8	-12.5	-44.9	13.9	-3.4	53.4	-33.5
Allam	-0.0	0.0	0.1	0.0	-0.1	-0.1	-0.0	0.0	0.0	0.1
LI-ion-low	-2.4	2.2	-3.1	0.5	0.2	1.5	9.4	-2.1	-7.8	-0.1
LDES-low	-1.1	0.2	90.7	0.3	-5.1	-8.5	0.0	-1.1	-10.9	-8.5
LDES-high	0.7	0.3	-24.8	0.4	4.9	25.7	21.7	0.5	-26.3	15.6
VRE-low	-15.9	-0.5	-22.9	-0.8	3.4	15.8	41.7	-22.9	11.9	10.9
VRE-high	12.5	-0.6	6.0	-1.0	-0.3	-3.5	-14.9	16.3	3.2	-1.3
H2_ind	-2.3	14.0	213.3	23.2	-1.0	-33.4	66.8	0.8	1.2	-25.4
DemFlex	-3.6	-9.7	-40.6	-1.1	1.2	12.4	0.7	0.3	-0.5	4.2
DemResp	-1.1	-2.6	-6.6	-0.2	-8.2	6.2	-62.4	1.1	762.5	2.6

Table D.5: Results of the effects' analysis at 50gCO_2/kWh emission intensity, showing the average impact (change in %) of each factor on the key metrics.

	SCOE	GenCapPeak	StorCapHours	VRE_Cap	Gas_Cap	Curtailment	CoV	MeanPrice	ExtrPriceBand	ZeroPriceBand
RFB (M)	-1.4	1.9	93.3	4.7	-8.9	-20.5	-27.6	1.2	129.5	-21.6
H2 (M)	0.0	-0.0	-0.0	-0.0	-0.0	-0.0	0.0	-0.0	0.0	0.0
Metal-air (M)	-0.2	0.7	109.4	1.3	-5.7	-13.1	1.2	-0.0	47.1	-12.1
Allam	-0.0	0.0	1.6	0.0	-0.3	-0.8	0.1	-0.0	0.0	-0.4
LI-ion-low	-2.4	3.1	-3.7	1.7	-0.5	7.8	8.3	-1.6	-8.0	3.6
LDES-low	-0.8	1.6	210.2	2.9	-9.3	-19.1	-4.1	0.0	-7.2	-15.0
LDES-high	0.4	-0.7	-21.3	-1.2	3.4	9.2	12.0	-0.3	-24.9	9.4
VRE-low	-14.4	9.2	24.2	16.5	-10.3	168.4	16.7	-17.1	11.1	119.5
VRE-high	9.7	-11.4	-13.2	-21.3	13.4	-82.7	7.2	9.4	-18.0	-70.4
H2_ind	-1.5	15.3	196.5	27.7	2.8	16.8	-14.0	3.3	181.8	-10.2
DemFlex	-3.8	-9.6	-35.4	-0.6	-1.4	34.0	4.4	0.5	-33.2	8.3
DemResp	-1.3	-3.2	-8.0	-1.2	-8.1	-0.3	-66.2	0.3	550.1	-1.6

Table D.6: Results of the effects' analysis at No Limit policy, showing the average impact (change in %) of each factor on the key metrics.

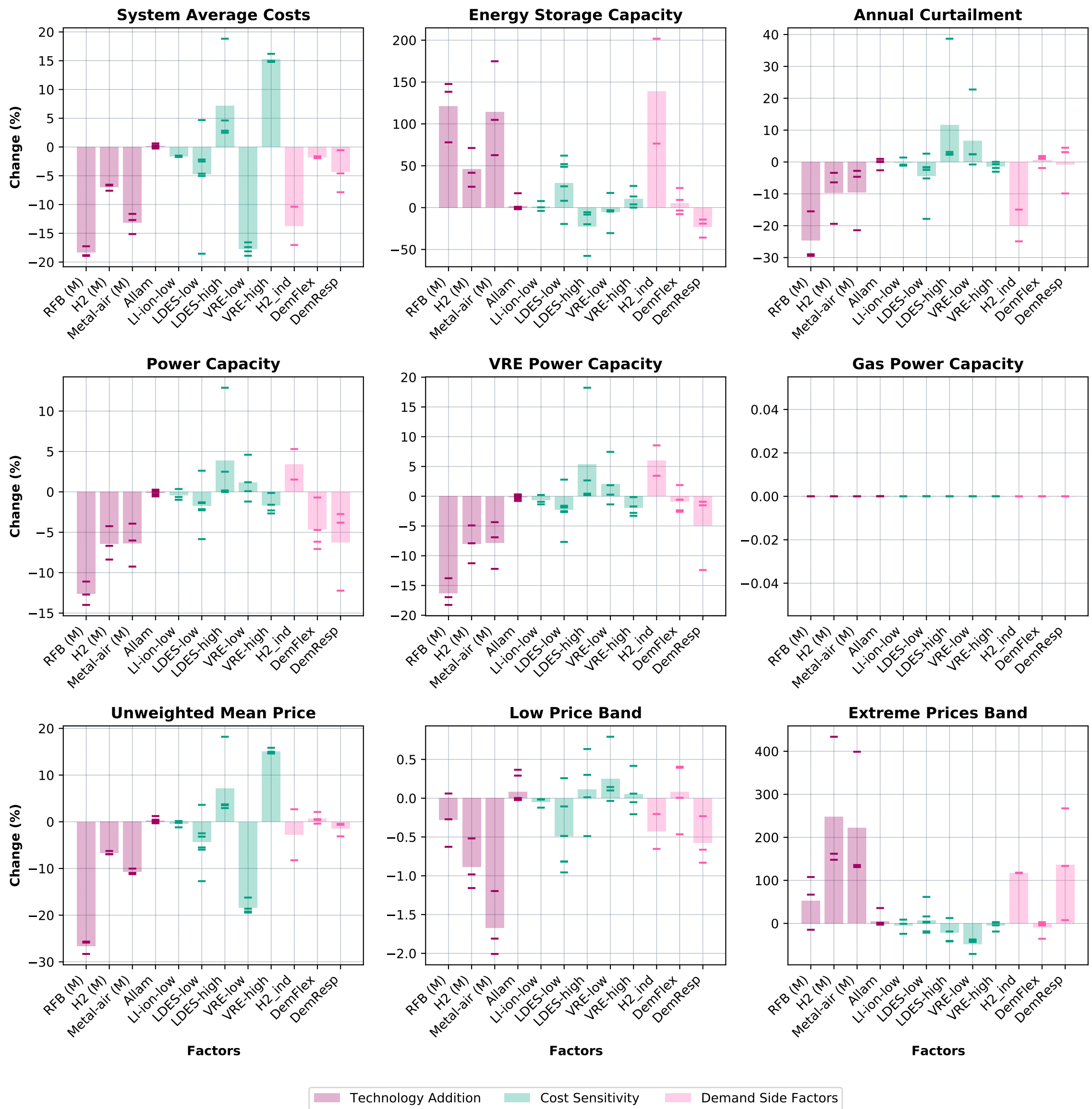

Figure D-1: Results of the effects' analysis at $0gCO_2/kWh$ emission intensity, showing the impact (change in %) of each factor on the key metrics. Bars describe the magnitude of the average change, while the small horizontal lines is the result of a single pair of experiments.

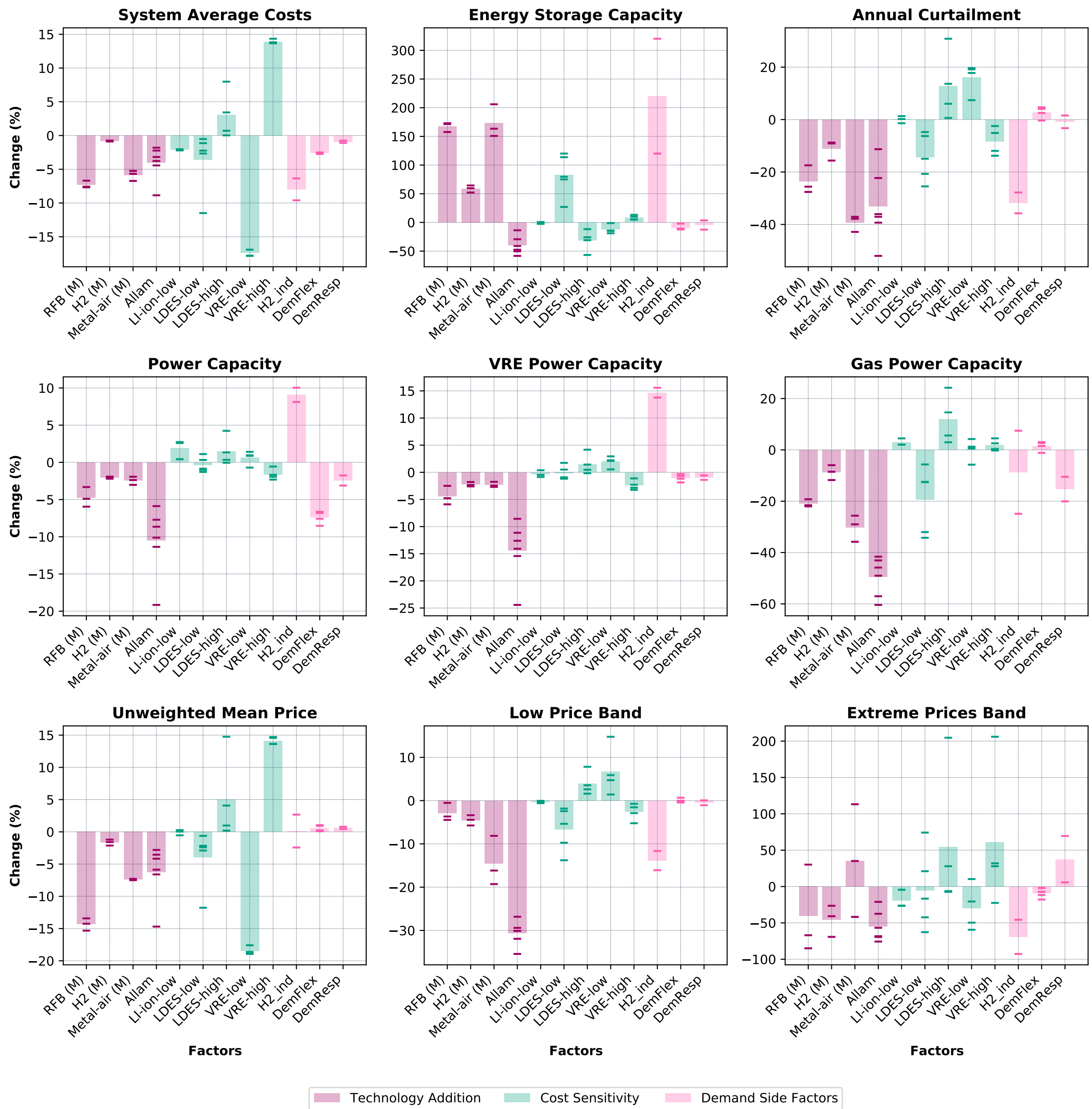

Figure D-2: Results of the effects' analysis at $1gCO_2/kWh$ emission intensity, showing the impact (change in %) of each factor on the key metrics. Bars describe the magnitude of the average change, while the small horizontal lines is the result of a single pair of experiments.

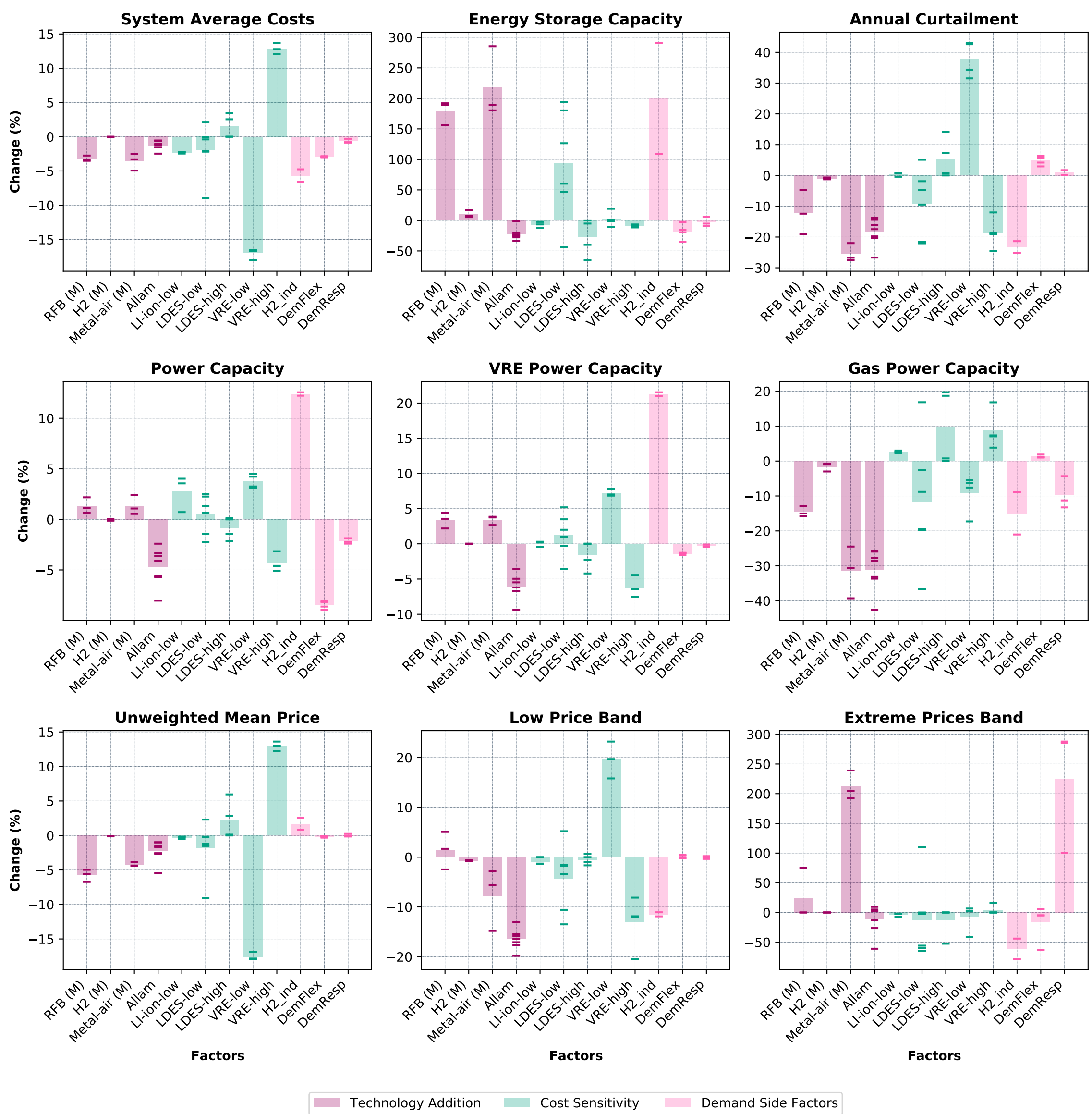

Figure D-3: Results of the effects' analysis at $5gCO_2/kWh$ emission intensity, showing the impact (change in %) of each factor on the key metrics. Bars describe the magnitude of the average change, while the small horizontal lines is the result of a single pair of experiments.

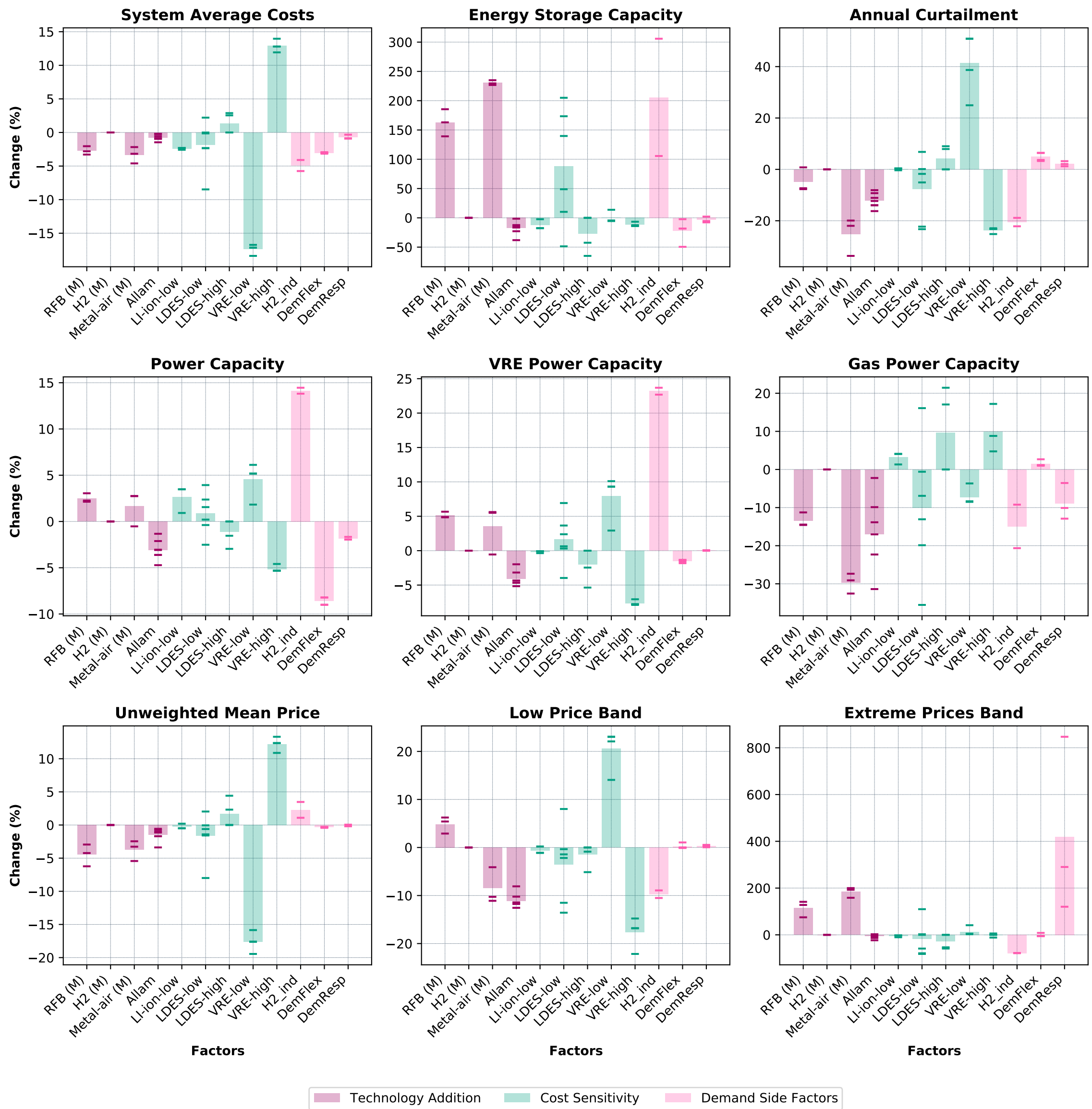

Figure D-4: Results of the effects' analysis at $10gCO_2/kWh$ emission intensity, showing the impact (change in %) of each factor on the key metrics. Bars describe the magnitude of the average change, while the small horizontal lines is the result of a single pair of experiments.

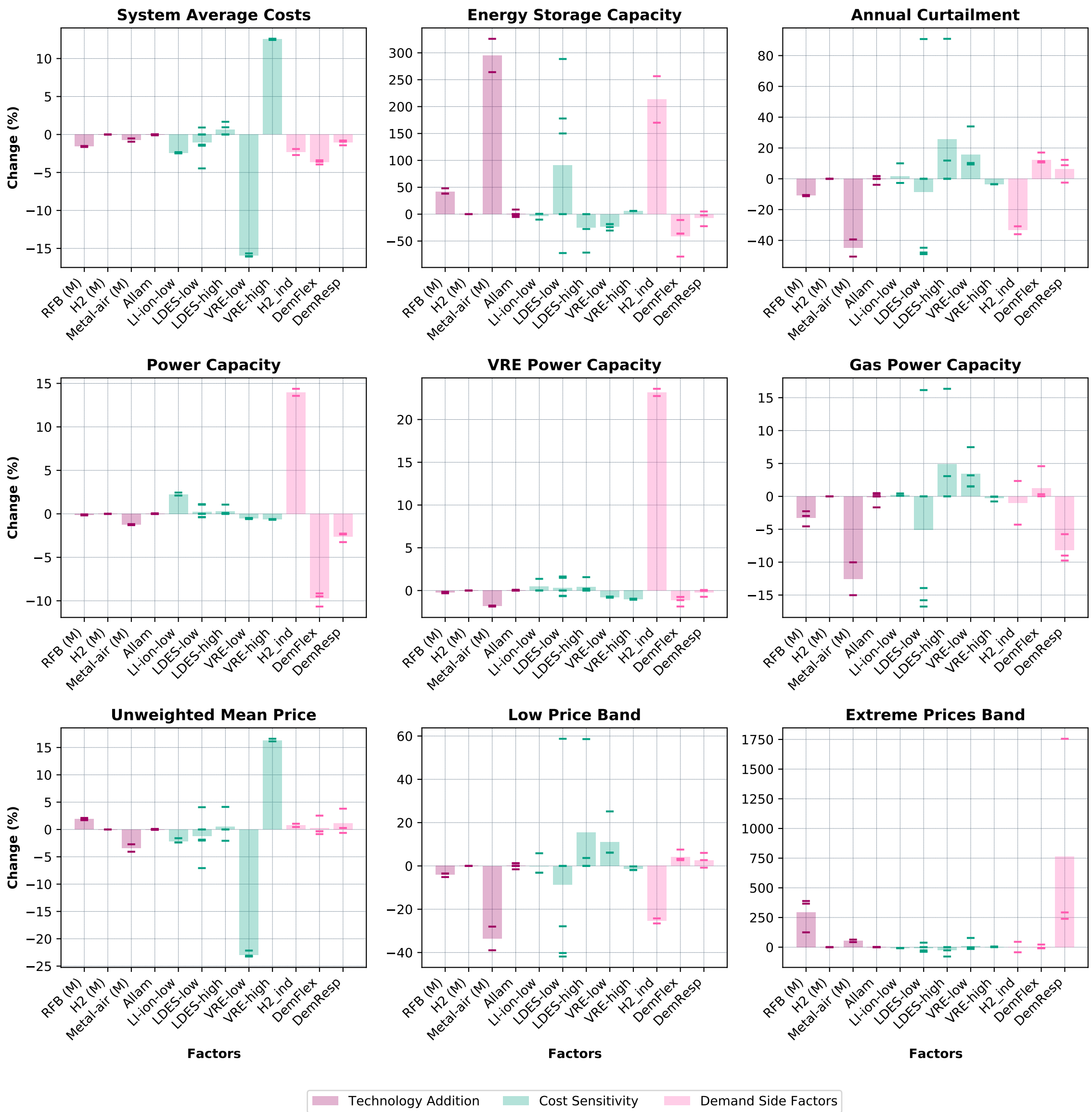

Figure D-5: Results of the effects' analysis at $50gCO_2/kWh$ emission intensity, showing the impact (change in %) of each factor on the key metrics. Bars describe the magnitude of the average change, while the small horizontal lines is the result of a single pair of experiments.

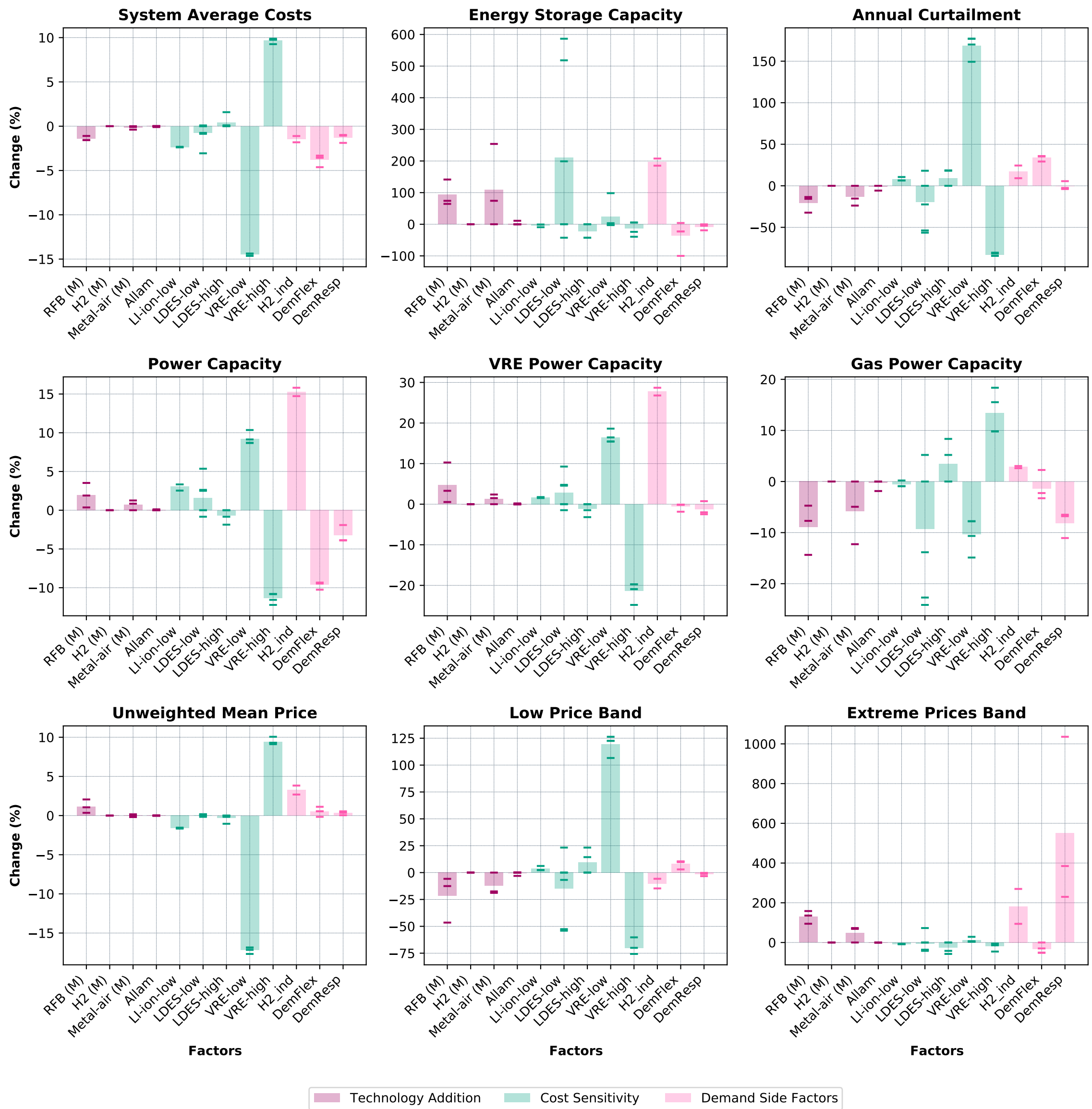

Figure D-6: Results of the effects' analysis at No Limits Policy, showing the impact (change in %) of each factor on the key metrics. Bars describe the magnitude of the average change, while the small horizontal lines is the result of a single pair of experiments.

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