On Incentive-Based Ancillary Service Markets for Incorporation of Renewable Energy Sources and Demand Response

A thesis submitted to attain the degree of

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(Dr. sc. ETH Zurich)

presented by

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2015
Preface

Watch your thoughts, for they become words.
Watch your words, for they become actions.
Watch your actions, for they become habits.
Watch your habits, for they become character.
Watch your character, for it becomes your destiny.

Unknown author

This thesis documents my research activities at the Power Systems Laboratory at ETH Zürich, starting from December 2010. I would like to express my sincere gratitude to Prof. Dr. Göran Andersson for providing me the opportunity to pursue my PhD at ETH Zurich. His time for questions and suggestions allowed me to explore a broad field in power systems economics and to gain a big picture of necessities in power system design. My special thanks go also to Prof. Dr. Tomás Gómez San Román for being my co-examiner. Further, I am very grateful about the possibility to spend time for research at the Renewable Energy Analysis Laboratory under supervision of Prof. Dr. Daniel Kirschen at the University of Washington in Seattle. I also appreciated the efforts of the whole crew in the Lab for providing me also personally a great time in the U.S. Finally, I thank Prof. Dr. Johanna Mathieu for the very productive collaboration and the sparkling ideas in numerous meetings.

Of course, I also would like to thank my friends and colleagues at the Power System Laboratory, with whom I had a great time with. Last but not least all students under my supervision, who accomplished a lot of interesting works.

Most of all, I am deeply grateful about the efforts, patience, and lenience of my family, who supported me whenever it was possible for them.
Abstract

An increasing share of renewable energy production and demand side participation call for progress in the design of electricity markets. Broadly, market designs must ensure the accord of short-term efficiency, which means that the products with the highest demand are produced and traded with a correct price, and long-term efficiency, which means that investments are done and markets evolve to a changing environment. In this thesis the focus lies on the design of ancillary service markets. Ancillary services are necessary to ensure a reliable and secure operation of the power system and are in liberalized markets supplementary traded to energy. The importance of ancillary service markets will likely rise in the future due to the challenges previously described.

However, current ancillary service market designs have several shortcomings. In particular, there do not exist financial incentives to avoid the reservation and deployment of ancillary services due to the socialization of costs. Further, demand side participation in ancillary service markets requires the establishment of a proper market framework, which enables fast and simple control of flexibility of the demand side, and simultaneously takes into account possible technical limitations and privacy considerations.

In the first part of the thesis, market frameworks for different wholesale platforms are presented, which ensure that ancillary services are procured based on the individual valuation of it. This enables the creation of financial incentives to abate the reservation of backup capacity. The main issue is that reliable electricity supply, and thus backup reserves for reliable system operation, can be seen as a public good. Therefore, market designs have to ensure that they are safe from being gamed by market participants. The proposed models are tested with regards to the
parametrization and compared with different benchmark approaches.

In the second part of the thesis, a market framework is presented which allows the financial settlement of demand side participation in ancillary service markets. System services are predefined through a contract-based framework, which allows the operation of the acquired flexibility through control signals. A new entity, an aggregator, is introduced which seeks to collect as much private information as possible in order to operate efficiently. The consumer tries to keep as much information as possible private. The proposed market designs balance these two conflicting market designs via mechanism design and the application of cooperative game theory. Simulation results show the impact of different design parameters on the exploitation of the demand response potential and the cost efficiency.
Kurzfassung


Im ersten Teil dieser Arbeit werden mögliche Marktdesigns präsentiert, welche eine Vorhaltung von Reserven entsprechend der individuellen Präferenzen der Konsumenten ermöglichen. Diese Designs ermöglichen die Schaffung von finanziellen Anreizen und, in weiterer Folge, die Verringerung der Notwendigkeit einer umfassenden Vorhaltung von Reserven. Das Hauptargument liegt in der Annahme, dass Reserven als

# Contents

List of Acronyms ........................................... xvi
Nomenclature ................................................... xxvii
List of Figures .................................................. xxxi
List of Tables .................................................... xxxiv

## 1 Introduction

1.1 Background and Motivation ................................. 1
1.2 Main Contributions of this Thesis .......................... 5
1.3 Thesis Outline .............................................. 6
1.4 List of Publications ......................................... 7

## I Allocation of Balancing Responsibility

### 2 Cost Allocation in a Centrally Operated Systems

2.1 Introduction and Motivation ................................ 13
2.2 Literature Review ........................................... 15
2.3 Modelling Framework ....................................... 16
   2.3.1 Cost Allocation of Event-Based Reserves ............ 16
   2.3.2 Cost Allocation of Non Event-Based Reserves ..... 24
   2.3.3 Cost Allocation of Ramping Services ............... 27
   2.3.4 Non-Linear Optimization ............................. 29
2.4 Simulation Setup .......................................... 34
## Contents

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>4.5.2 Impact of Preferences on Energy Payments</td>
<td>86</td>
</tr>
<tr>
<td>4.5.3 Impact of Congestion on BRP Payments</td>
<td>88</td>
</tr>
<tr>
<td>4.6 Summary</td>
<td>92</td>
</tr>
<tr>
<td><strong>5 Closure Part I</strong></td>
<td>93</td>
</tr>
<tr>
<td>5.1 Summary</td>
<td>93</td>
</tr>
<tr>
<td>5.2 Conclusion</td>
<td>94</td>
</tr>
<tr>
<td>5.3 Outlook</td>
<td>95</td>
</tr>
<tr>
<td><strong>II Demand Response for System Services</strong></td>
<td>97</td>
</tr>
<tr>
<td>6 On Market-Like Incorporation of Demand Response</td>
<td>99</td>
</tr>
<tr>
<td>6.1 Introduction and Motivation</td>
<td>99</td>
</tr>
<tr>
<td>6.2 Price Signals</td>
<td>102</td>
</tr>
<tr>
<td>6.3 Price/Quantity Bidding by Individual Loads</td>
<td>105</td>
</tr>
<tr>
<td>6.4 Direct Load Control and Contract-Based Rewarding</td>
<td>106</td>
</tr>
<tr>
<td>6.4.1 General Analysis</td>
<td>106</td>
</tr>
<tr>
<td>6.4.2 Provision of Adequate Control Signals</td>
<td>108</td>
</tr>
<tr>
<td>6.5 Summary</td>
<td>115</td>
</tr>
<tr>
<td>7 Design of Contract-Based Rewards</td>
<td>117</td>
</tr>
<tr>
<td>7.1 Aggregation and the Role of Information</td>
<td>117</td>
</tr>
<tr>
<td>7.1.1 Introduction and Motivation</td>
<td>117</td>
</tr>
<tr>
<td>7.1.2 Literature Review</td>
<td>119</td>
</tr>
<tr>
<td>7.1.3 The Benchmark: Centralized Dispatch</td>
<td>120</td>
</tr>
<tr>
<td>7.1.4 Centralized Contract Design</td>
<td>122</td>
</tr>
<tr>
<td>7.1.5 Decentralized Contract Design</td>
<td>125</td>
</tr>
<tr>
<td>7.1.6 Simulation Setup</td>
<td>130</td>
</tr>
<tr>
<td>7.1.7 Results</td>
<td>131</td>
</tr>
<tr>
<td>7.1.8 Summary</td>
<td>137</td>
</tr>
<tr>
<td>7.2 Non-Linear Contract Design</td>
<td>138</td>
</tr>
<tr>
<td>7.2.1 Motivation</td>
<td>138</td>
</tr>
</tbody>
</table>
Contents

B.3.3 Non-Linear Tariff Design for Reserve Capacity . 184

B.4 Chapter VI .............................................. 187
  B.4.1 Bilevel Optimization ............................. 187
  B.4.2 Cooperative Game Theory ......................... 189
  B.4.3 Continuous Q-learning ............................ 189

Bibliography ................................................. 191

Curriculum Vitae ............................................ 207
# List of Acronyms

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>AGC</td>
<td>Automatic Generation Control</td>
</tr>
<tr>
<td>ACE</td>
<td>Area Control Error</td>
</tr>
<tr>
<td>AS</td>
<td>Ancillary Services</td>
</tr>
<tr>
<td>ASM</td>
<td>Ancillary Service Market</td>
</tr>
<tr>
<td>BRP</td>
<td>Balance Responsible Party</td>
</tr>
<tr>
<td>BSP</td>
<td>Balancing Service Provider</td>
</tr>
<tr>
<td>CH</td>
<td>Chebyshev</td>
</tr>
<tr>
<td>COPT</td>
<td>Capacity Outage Probability Table</td>
</tr>
<tr>
<td>CS</td>
<td>Consumer Surplus</td>
</tr>
<tr>
<td>DAM</td>
<td>Day-ahead Market</td>
</tr>
<tr>
<td>DFT</td>
<td>Discrete Fourier Transform</td>
</tr>
<tr>
<td>DLC</td>
<td>Direct Load Control</td>
</tr>
<tr>
<td>DOE</td>
<td>U.S. Department of Energy</td>
</tr>
<tr>
<td>DR</td>
<td>Demand Response</td>
</tr>
<tr>
<td>EENS</td>
<td>Expected Energy Not Served</td>
</tr>
<tr>
<td>ENTSO-E</td>
<td>European Network of Transmission System Operators for Electricity</td>
</tr>
<tr>
<td>EWMA</td>
<td>Exponential Weighted Moving Average</td>
</tr>
<tr>
<td>Acronym</td>
<td>Description</td>
</tr>
<tr>
<td>---------</td>
<td>-------------</td>
</tr>
<tr>
<td>FIR</td>
<td>Finite Impulse Response</td>
</tr>
<tr>
<td>FIT</td>
<td>Feed-In Tariff</td>
</tr>
<tr>
<td>FFT</td>
<td>Fast Fourier Transform</td>
</tr>
<tr>
<td>FFTW</td>
<td>First Fundamental Welfare Theorem</td>
</tr>
<tr>
<td>IDM</td>
<td>Intra-day Market</td>
</tr>
<tr>
<td>IEEE</td>
<td>Institute of Electrical and Electronics Engineers</td>
</tr>
<tr>
<td>IIR</td>
<td>Infinite Impulse Response</td>
</tr>
<tr>
<td>ISO</td>
<td>Independent System Operator</td>
</tr>
<tr>
<td>KKT</td>
<td>Karush Kuhn Tucker Conditions</td>
</tr>
<tr>
<td>LEQ</td>
<td>Lindahl Equilibrium</td>
</tr>
<tr>
<td>LMP</td>
<td>Locational Marginal Pricing</td>
</tr>
<tr>
<td>LOC</td>
<td>Lost Opportunity Costs</td>
</tr>
<tr>
<td>MINLP</td>
<td>Mixed Integer Non Linear Program</td>
</tr>
<tr>
<td>MPEC</td>
<td>Mathematical Program With Equilibrium Constraints</td>
</tr>
<tr>
<td>PI</td>
<td>Proportional Integral Controller</td>
</tr>
<tr>
<td>PS</td>
<td>Producer Surplus</td>
</tr>
<tr>
<td>RES</td>
<td>Renewable Energy Sources</td>
</tr>
<tr>
<td>RT-SCED</td>
<td>Real Time Security Constrained Economic Dispatch</td>
</tr>
<tr>
<td>TSO</td>
<td>Transmission System Operator</td>
</tr>
<tr>
<td>VOLL</td>
<td>Value of Lost Load</td>
</tr>
</tbody>
</table>
List of Symbols

The thesis contains variable and parameter names which do not change the meaning throughout the thesis. Additionally, parts of the nomenclature are shown chapter-wise for quick reference.

PART I

Vectors

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Units</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$a$</td>
<td></td>
<td>Vector of parameters,</td>
</tr>
<tr>
<td>$u$</td>
<td></td>
<td>Vector of discrete decision variables,</td>
</tr>
<tr>
<td>$x$</td>
<td></td>
<td>Vector of continuous decision variables,</td>
</tr>
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Numbers and Indices

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Units</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$i, j, t, \tau$</td>
<td></td>
<td>Generators, loads, time instant, time duration</td>
</tr>
<tr>
<td>$s, q, qr$</td>
<td></td>
<td>Segment of cost curves,</td>
</tr>
<tr>
<td>$M$</td>
<td></td>
<td>Large constant,</td>
</tr>
<tr>
<td>$N_{Br}$</td>
<td></td>
<td>Number of branches,</td>
</tr>
<tr>
<td>$N_L, N_G, N_T$</td>
<td></td>
<td>Number of generators, loads, time instances,</td>
</tr>
<tr>
<td>$N_P$</td>
<td></td>
<td>Number of segments of benefit curve for reserves,</td>
</tr>
<tr>
<td>$N_Q$</td>
<td></td>
<td>Number of segments of cost curve for abated reserve requirements,</td>
</tr>
<tr>
<td>$N_{QR}$</td>
<td></td>
<td>Number of segments of cost curve for abated ramping requirements,</td>
</tr>
<tr>
<td>$N_S$</td>
<td></td>
<td>Number of segments of generator cost curve,</td>
</tr>
</tbody>
</table>
## List of Symbols

### Parameters

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<thead>
<tr>
<th>Symbol</th>
<th>Units</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$(a, b, c)_{Em}^{t}$</td>
<td></td>
<td>Cost parameters of emissions at time $t$,</td>
</tr>
<tr>
<td>$(a, b, c)_{Resup,ab}^{noevt,w,t}$</td>
<td></td>
<td>Cost parameters of abating fluctuations of wind site $w$ at time $t$,</td>
</tr>
<tr>
<td>$(a, b, c)_{Resup,cap}^{noevt,j,t}$</td>
<td></td>
<td>Parameters of benefit of reserve capacity of BRP $j$ at time $t$,</td>
</tr>
<tr>
<td>$\overline{a}_{Resup,ab}^{noevt,w,t}$</td>
<td></td>
<td>Numeric factor,</td>
</tr>
<tr>
<td>$\overline{B}_{Resup/dn,cap}^{noevt,j,t}$</td>
<td></td>
<td>Benefit of up/down-reserve capacity of BRP $j$ at time $t$,</td>
</tr>
<tr>
<td>$C_{i}^{Rup}$</td>
<td>$\frac{m.u.}{MW h}$</td>
<td>Cost factor for up-ramping efforts of unit $i$,</td>
</tr>
<tr>
<td>$C_{i}^{Rdn}$</td>
<td>$\frac{m.u.}{MW h}$</td>
<td>Cost factor for down-ramping efforts of unit $i$,</td>
</tr>
<tr>
<td>$C_{i}^{NoLoad}$</td>
<td>$m.u.$</td>
<td>No load costs of generator $i$,</td>
</tr>
<tr>
<td>$C_{i}^{Start}$</td>
<td>$m.u.$</td>
<td>Start-up costs of unit $i$ at time $t$,</td>
</tr>
<tr>
<td>$Em^{t}$</td>
<td>$\frac{m.u.}{tCO_2}$</td>
<td>Segment $e$ of emission cost curve at time $t$,</td>
</tr>
<tr>
<td>$F_{evt,j,t}^{Resup/dn}$</td>
<td></td>
<td>Scaling factor for marginal benefit of event-based reserve requirements for load $j$ at time $t$,</td>
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<tr>
<td>$F_{noevt,w,t}^{ab}$</td>
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<td>Scaling factor for marginal cost of abating reserve requirements for load $j$ at time $t$,</td>
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<tr>
<td>$F_{Rup/dn,ab}^{j,t}$</td>
<td></td>
<td>Scaling factor for marginal cost of abating ramping requirements for load $j$ at time $t$,</td>
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<tr>
<td>$F_{Resup/dn,en}^{j,t}$</td>
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<td>Scaling factor for marginal benefit of balancing energy of BRP $j$ at time $t$,</td>
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<tr>
<td>$F_{noevt,w,t}^{ab}$</td>
<td></td>
<td>Numeric factor,</td>
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<tr>
<td>$G_{i,t}^{j,t}$</td>
<td>$MW$</td>
<td>Maximal generation of generator $i$ at time $t$,</td>
</tr>
<tr>
<td>$G_{i,t}^{Rup/Rdn}$</td>
<td>$\frac{MW}{h}$</td>
<td>Minimal generation of generator $i$ at time $t$,</td>
</tr>
<tr>
<td>$I_{w}^{w}$</td>
<td></td>
<td>Maximal up/down ramp rate of generator $i$,</td>
</tr>
<tr>
<td>$MB_{Resup/dn}^{evt,j,p,t}$</td>
<td>$\frac{m.u.}{MW}$</td>
<td>$p^{th}$-segment of marginal benefit of event based up/dn-reserve capacity for load $j$ at time $t$,</td>
</tr>
<tr>
<td>$MB_{Resup/dn}^{evt,j,t}$</td>
<td>$\frac{m.u.}{MW}$</td>
<td>Marginal benefit of event based up/dn-reserve capacity for load $j$ at time $t$,</td>
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</tbody>
</table>
### List of Symbols

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$MB_{\text{evt},j,t}^\text{Resup/dn,\text{min1}}$</td>
<td>Marginal benefit of event based up/dn-reserve capacity for aggregated loads excluding $j$ at time $t$,</td>
</tr>
<tr>
<td>$MB_{\text{evt},p,t}^\text{Resup/dn}$</td>
<td>$p^{th}$-segment of the aggregated marginal benefit of event based up/dn-reserve capacity at time $t$,</td>
</tr>
<tr>
<td>$MB_{\text{noevt},j,t}^\text{Resup/dn,\text{cap}}$</td>
<td>Marginal benefit of up/dn-reserve capacity of BRP $j$ at time $t$,</td>
</tr>
<tr>
<td>$MB_{\text{noevt},q,t}^\text{Resup/dn,\text{en}}$</td>
<td>$q^{th}$-segment of aggregated marginal benefit of balancing energy of BRPs at time $t$,</td>
</tr>
<tr>
<td>$MC_{\text{noevt},j,t}^\text{Resup/dn,\text{ab}}$</td>
<td>$q^{th}$-segment of marginal costs of abating non-event up/dn-reserve capacity needs of load $j$ at time $t$,</td>
</tr>
<tr>
<td>$MC_{\text{noevt},j,t}^\text{Resup/dn,\text{ab}}$</td>
<td>Marginal costs of abating non-event up/dn-reserve capacity needs of load $j$ at time $t$,</td>
</tr>
<tr>
<td>$MC_{\text{noevt},j,t}^\text{Resup/dn,\text{ab}}$</td>
<td>$q^{th}$-segment of the aggregated marginal costs of abating non-event up/dn-reserve capacity needs at time $t$,</td>
</tr>
<tr>
<td>$MC_{\text{noevt},q,t}^\text{Resup/dn,\text{ab}}$</td>
<td>$q^{th}$-segment of the aggregated marginal costs of up/down shifted capacity at time $t$,</td>
</tr>
<tr>
<td>$MC_{\text{noevt},q,t}^\text{Resup/dn,\text{ab}}$</td>
<td>$q^{th}$-segment of the aggregated marginal costs of up/down shifted capacity at time $t$,</td>
</tr>
<tr>
<td>$MC_{\text{noevt},q,t}^\text{Resup/dn,\text{ab}}$</td>
<td>$q^{th}$-segment of the aggregated marginal costs of up/down shifted capacity at time $t$,</td>
</tr>
<tr>
<td>$MC_{\text{noevt},q,t}^\text{Resup/dn,\text{ab}}$</td>
<td>$q^{th}$-segment of the aggregated marginal costs of up/down shifted capacity at time $t$,</td>
</tr>
<tr>
<td>$MC_{\text{noevt},q,t}^\text{Resup/dn,\text{ab}}$</td>
<td>$q^{th}$-segment of the aggregated marginal costs of up/down shifted capacity at time $t$,</td>
</tr>
<tr>
<td>$MC_{\text{noevt},q,t}^\text{Resup/dn,\text{ab}}$</td>
<td>$q^{th}$-segment of the aggregated marginal costs of up/down shifted capacity at time $t$,</td>
</tr>
<tr>
<td>$MC_{\text{noevt},q,t}^\text{Resup/dn,\text{ab}}$</td>
<td>$q^{th}$-segment of the aggregated marginal costs of up/down shifted capacity at time $t$,</td>
</tr>
</tbody>
</table>
List of Symbols

\( MC_{\text{noevt},i,s,t}^{\text{Resup/dn,seg,en}} \text{ MW} \) \( s^{th}\)-segment of marginal costs of providing non-event up/dn-reserve energy needs of generator \( i \) at time \( t \),

\( MC_{i,s,t}^{\text{Resup/dn,seg,en}} \text{ MW} \) \( s^{th}\)-segment of marginal costs of providing balancing energy needs of generator \( i \) at time \( t \),

\( Q_{\text{evt},j,t}^{\text{Resup/dn}} \) Assumed range of marginal benefit curve of event-based reserve requirements for load \( j \) at time \( t \),

\( Q_{\text{noevt},j/w,t}^{\text{Resup/dn,ab}} \) Assumed range of marginal cost curve of abating reserve requirements for load \( j \) at time \( t \),

\( Q_{j,t}^{\text{Resup/dn,en}} \) Assumed range for marginal benefit curve of balancing energy for BRP \( j \) at time \( t \),

\( Q_{j,t}^{\text{Resup/dn,cap}} \) Assumed range for marginal benefit curve of reserve capacity for BRP \( j \) at time \( t \),

\( R_{\text{noevt},t}^{\text{Req,Resup/dn,cap}} \text{ MW} \) Non-event reserve capacity requirements without decentralized balancing at time \( t \),

\( R_{\text{evt},t}^{\text{Req,Resup/dn,cap}} \text{ MW} \) Event-based reserve capacity requirements without decentralized balancing at time \( t \),

\( R_{\text{noevt},t}^{\text{Req,Resup/dn,en}} \text{ MWh} \) Non-event reserve energy requirements \( t \),

\( R_{\text{evt},t}^{\text{Req,Resup/dn,en}} \text{ MWh} \) Event-based reserve energy requirements \( t \),

\( p_{j}^{\text{noevt},w,t}^{\text{Resup,ab}} \) Share \( p \) of load \( j \) for revenue sufficiency,

\( \eta_{\text{noevt},j/w,t}^{\text{Resup/dn,ab}} \) Cost parameters of abating fluctuations of wind site \( w \) at time \( t \),

\( \eta_{\text{evt},j,t}^{\text{Resup/dn}} \) Elasticity of marginal benefit of event-based reserve requirements for load \( j \) at time \( t \),

\( \eta_{\text{noevt},j/w,t}^{\text{Resup/dn,ab}} \) Elasticity of marginal costs of abating reserve requirements for load \( j \) at time \( t \),

\( \eta_{\text{Rup/dn,ab}}^{\text{Resup/dn,ab}} \) Elasticity of marginal costs of abating ramping requirements for load \( j \) at time \( t \),

\( \eta_{j,t}^{\text{Resup/dn,en}} \) Elasticity of marginal benefit for balancing energy of BRP \( j \) at time \( t \),

\( \lambda_{\text{En,DA}}^{n,t} \text{ m.u.} \) Day-ahead price of traded energy at node \( n \) at time \( t \),

\( \lambda_{\text{Resup/dn,en}}^{t} \text{ m.u.} \) Price of deployed reserve energy at time \( t \).
## Variables

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Units</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$C_{\text{Ramp}}^i$</td>
<td>m.u.</td>
<td>Total costs of ramping of unit $i$,</td>
</tr>
<tr>
<td>$D_{\text{en}}^{j,t}$</td>
<td>MWh</td>
<td>Demand for energy of load $j$ at time $t$,</td>
</tr>
<tr>
<td>$D_{\text{d,en}}^{j,t}$</td>
<td>MWh</td>
<td>Deterministic component of demand for energy of load $j$ at time $t$,</td>
</tr>
<tr>
<td>$\tilde{D}_{\text{en}}^{j,t}$</td>
<td>MWh</td>
<td>Stochastic component of demand for energy of load $j$ at time $t$,</td>
</tr>
<tr>
<td>$D_{\text{Resup/dn,en,seg}}^{q,t}$</td>
<td>MWh</td>
<td>$q^{th}$-segment of the aggregated demand for balancing energy at time $t$,</td>
</tr>
<tr>
<td>$E_{\text{en}}^i,t$</td>
<td>MWh</td>
<td>Energy production of unit $i$ at time $t$,</td>
</tr>
<tr>
<td>$E_{\text{CO}_2}^t$</td>
<td>tCO$_2$</td>
<td>Emissions at time $t$,</td>
</tr>
<tr>
<td>$ER_{\text{Rup/Rdn}}^{i,t}$</td>
<td>MWh</td>
<td>Energy content of up/dn-ramping of unit $i$ at time $t$,</td>
</tr>
<tr>
<td>$LOC_{\text{Resup}}^{\text{evt},i,t}$</td>
<td>m.u.</td>
<td>Lost opportunity costs of providing up event-based reserve capacity of unit $i$,</td>
</tr>
<tr>
<td>$LOC_{\text{Resup}}^{\text{noevt},i,t}$</td>
<td>m.u.</td>
<td>Lost opportunity costs of providing up non-event based reserve capacity of unit $i$,</td>
</tr>
<tr>
<td>$G_{\text{En}}^{i,s,t}$</td>
<td>MW</td>
<td>Generation of energy in cost segment $s$ of unit $i$ at time $t$,</td>
</tr>
<tr>
<td>$G_{\text{Resup/dn,cap}}^{\text{noevt},i,s,t}$</td>
<td>MW</td>
<td>Non-event based capacity in cost segment $s$ of unit $i$ at time $t$,</td>
</tr>
<tr>
<td>$G_{\text{Resup/dn,cap}}^{\text{evt},i,s,t}$</td>
<td>MW</td>
<td>Event-based reserves in cost segment $s$ of unit $i$ at time $t$,</td>
</tr>
<tr>
<td>$G_{\text{Resup/dn,en}}^{\text{noevt},i,s,t}$</td>
<td>MWh</td>
<td>Non-event based reserve energy in cost segment $s$ of unit $i$ at time $t$,</td>
</tr>
<tr>
<td>$G_{\text{Resup/dn,en}}^{\text{evt},i,s,t}$</td>
<td>MWh</td>
<td>Event-based reserve energy in cost segment $s$ of unit $i$ at time $t$,</td>
</tr>
<tr>
<td>$G_{\text{En}}^{i,t}$</td>
<td>MWh</td>
<td>Total generation of energy unit $i$ at time $t$,</td>
</tr>
<tr>
<td>$G_{\text{Resup/dn,cap}}^{\text{noevt},i,t}$</td>
<td>MW</td>
<td>Total provision of non-event based capacity of unit $i$ at time $t$,</td>
</tr>
<tr>
<td>$G_{\text{Resup/dn,cap}}^{\text{evt},i,t}$</td>
<td>MW</td>
<td>Total provision of event-based reserves of unit $i$ at time $t$,</td>
</tr>
<tr>
<td>$G_{\text{Resup/dn,seg}}^{\text{noevt},i,t}$</td>
<td>MWh</td>
<td>Total provision of non-event based reserve energy of unit $i$ at time $t$,</td>
</tr>
<tr>
<td>$G_{\text{Resup/dn,seg}}^{\text{evt},i,t}$</td>
<td>MWh</td>
<td>Total provision of event-based reserve energy of unit $i$ at time $t$,</td>
</tr>
</tbody>
</table>
List of Symbols

\[ G_{\text{Resup/dn,en,seg}}^{s,t} \quad MW h \quad \text{s}^{th}-\text{segment of the aggregated production of balancing energy at time } t, \]

\[ P_{\text{Resup/dn,ab}}^{\text{noevent},j,q,t} \quad MW \quad \text{Segment q abated amount of up/down reserve capacity needs of load } j \text{ at time } t, \]

\[ P_{\text{Rup/dn,ab}}^{qr,t} \quad MW \quad \text{Segment } qr \text{ of aggregated amount of up/down shifted capacity at time } t, \]

\[ P_{\text{Rup/dn,ab}}^{t} \quad MW \quad \text{Aggregated amount of up/down shifted capacity at time } t, \]

\[ u_{i,t} \quad \text{Binary variable for ON/OFF decision of unit } i \text{ at time } t, \]

\[ \tau_{\text{Rup/Rdn}}^{i,t} \quad h \quad \text{Time duration of up/dn-ramping unit } i \text{ at time } t, \]

\[ \omega_{\text{Rup/dn}}^{j,t} \quad h \quad \text{Binary variable to avoid simultaneous up/down energy shifting of load } j \text{ at time } t. \]

Part II

Numbers and Indices

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Units</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>( i, j, t )</td>
<td>Generators, loads, time instant,</td>
<td></td>
</tr>
<tr>
<td>( s, e )</td>
<td>Scenario of reserve energy requirements,</td>
<td></td>
</tr>
<tr>
<td>( b, \tau )</td>
<td>Cost segment of energy storage,</td>
<td></td>
</tr>
<tr>
<td>( N_{G,L,T} )</td>
<td>Number of generators, loads, time instances for capacity reservation,</td>
<td></td>
</tr>
<tr>
<td>( N_{\tau} )</td>
<td>Number of time instances for energy,</td>
<td></td>
</tr>
<tr>
<td>( M_{E} )</td>
<td>Large constant.</td>
<td></td>
</tr>
</tbody>
</table>

Parameters

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Units</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>( a_{\text{Stor/Resup/Resdn}}^{j,t} )</td>
<td>Fixed cost parameter for reserve capacity components of consumer ( j ) at time ( t ),</td>
<td></td>
</tr>
<tr>
<td>( \bar{a}_{\text{Resup/dn,cap}}^{j,t} )</td>
<td>Estimated fixed cost parameter for reserve capacity components of consumer ( j ) at time ( t ).</td>
<td></td>
</tr>
<tr>
<td>Symbol</td>
<td>Unit</td>
<td>Description</td>
</tr>
<tr>
<td>---------------</td>
<td>------------</td>
<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>( \tilde{a}_C^t )</td>
<td>m.u.</td>
<td>Estimated fixed cost parameter for cost of coalition formation time ( t ),</td>
</tr>
<tr>
<td>AGC( ^t )</td>
<td>MW</td>
<td>Activated generation control at time ( t ),</td>
</tr>
<tr>
<td>ACE( ^t )</td>
<td>MW</td>
<td>Area control error at time ( t ),</td>
</tr>
<tr>
<td>ACE( _\text{open loop}^t )</td>
<td>MW</td>
<td>Area control error in case of no AGC at time ( t ),</td>
</tr>
<tr>
<td>( b_{\text{Stor/Resup/Resdn}}^{j,t} )</td>
<td>m.u./MW</td>
<td>Linear cost parameter for reserve capacity components of consumer ( j ) at time ( t ),</td>
</tr>
<tr>
<td>( \tilde{b}_{\text{Resup/dn, cap}}^{j,t} )</td>
<td>m.u./MW</td>
<td>Estimated linear cost parameter for reserve capacity components of consumer ( j ) at time ( t ),</td>
</tr>
<tr>
<td>( \tilde{b}_C^t )</td>
<td>m.u./MW</td>
<td>Estimated linear cost parameter for cost of coalition formation at time ( t ),</td>
</tr>
<tr>
<td>( B )</td>
<td></td>
<td>Frequency bias factor,</td>
</tr>
<tr>
<td>( c_{\text{Stor/Resup/Resdn}}^{j,t} )</td>
<td>m.u./MW</td>
<td>Quadratic cost parameter for reserve capacity components of consumer ( j ) at time ( t ),</td>
</tr>
<tr>
<td>( \tilde{c}_{\text{Resup/dn, cap}}^{j,t} )</td>
<td>m.u./MW</td>
<td>Estimated quadratic cost parameter for reserve capacity components of consumer ( j ) at time ( t ),</td>
</tr>
<tr>
<td>( \tilde{c}_C^t )</td>
<td>m.u./MW²</td>
<td>Estimated quadratic cost parameter for cost of coalition formation at time ( t ),</td>
</tr>
<tr>
<td>( D_{\text{Stor/Resup/Resdn}}^{j,t} )</td>
<td>MW</td>
<td>Maximal consumption of load ( j ) at time ( t ),</td>
</tr>
<tr>
<td>( D_{\text{Resup/dn, cap}}^{j,t} )</td>
<td>MW</td>
<td>Maximal up/down reserve capacity provision of load ( j ) at time ( t ),</td>
</tr>
<tr>
<td>( E_{1}^{j} )</td>
<td>MWh</td>
<td>Initial charging level of storage of consumer ( j ),</td>
</tr>
<tr>
<td>( E_{F}^{j} )</td>
<td>MWh</td>
<td>Final charging level of storage of consumer ( j ),</td>
</tr>
<tr>
<td>( \overline{E}^{j} )</td>
<td>MWh</td>
<td>Maximal charging level of storage of consumer ( j ),</td>
</tr>
<tr>
<td>( \underline{E}^{j} )</td>
<td>MWh</td>
<td>Minimal charging level of storage of consumer ( j ),</td>
</tr>
<tr>
<td>( f )</td>
<td>Hz</td>
<td>Measured frequency,</td>
</tr>
<tr>
<td>( f_{0} )</td>
<td>Hz</td>
<td>Set value of the frequency,</td>
</tr>
<tr>
<td>( G_{i,t} )</td>
<td>MW</td>
<td>Maximal generation of generator ( i ) at time ( t ),</td>
</tr>
</tbody>
</table>
List of Symbols

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Units</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>$G_{i,t}$</td>
<td>$MW$</td>
<td>Minimal generation of generator $i$ at time $t$,</td>
</tr>
<tr>
<td>$\overline{G}_{\text{Resup/dn,cap}}$</td>
<td>$MW$</td>
<td>Maximal up/down reserve capacity provision of generator $i$ at time $t$,</td>
</tr>
<tr>
<td>$\overline{G}_{i,t}$</td>
<td>$MW$</td>
<td>Maximal generation of generator $i$ at time $t$,</td>
</tr>
<tr>
<td>$Inc_{i,t}$</td>
<td>$m.u.$</td>
<td>Monetary incentive for coalition formation,</td>
</tr>
<tr>
<td>$MC_{En}^{i,t}$</td>
<td>$m.u./$ MWh</td>
<td>Marginal cost of energy production of generator $i$ at time $t$,</td>
</tr>
<tr>
<td>$MC_{\text{Resup/dn,cap}}^{i,t}$</td>
<td>$m.u./$ MW</td>
<td>Marginal cost of up/down reserve capacity reservation of generator $i$ at time $t$,</td>
</tr>
<tr>
<td>$MC_{\text{Resup/dn,en}}^{i,\tau}$</td>
<td>$m.u./$ MWh</td>
<td>Marginal cost of up/down reserve energy provision of generator $i$ at time $\tau$,</td>
</tr>
<tr>
<td>$MC_{\text{Resup/dn,cap}}^{j,t}$</td>
<td>$m.u./$ MW</td>
<td>Marginal cost of up/down reserve capacity reservation of consumer $j$ at time $t$,</td>
</tr>
<tr>
<td>$MC_{\text{Resup/dn,en}}^{j,\tau}$</td>
<td>$m.u./$ MWh</td>
<td>Marginal cost of up/down reserve energy provision of consumer $j$ at time $\tau$,</td>
</tr>
<tr>
<td>$\tilde{MC}_{\text{Resup/dn,cap}}^{j,t}$</td>
<td>$m.u./$ MW</td>
<td>Estimated marginal cost for reserve capacity components of consumer $j$ at time $t$,</td>
</tr>
<tr>
<td>$\tilde{MC}_{\text{Resup/dn,en}}^{j,\tau}$</td>
<td>$m.u./$ MWh</td>
<td>Estimated marginal cost for reserve energy of consumer $j$ at time $\tau$,</td>
</tr>
<tr>
<td>$p_{\text{Resup/dn,cap}}^{j,t}$</td>
<td>$m.u.$</td>
<td>Price signal for reserve capacity provision to consumer $j$ at time $t$,</td>
</tr>
<tr>
<td>$P_{\text{T}_i}$</td>
<td>$MW$</td>
<td>Measured value of total power exchange,</td>
</tr>
<tr>
<td>$P_{\text{T0}_i}$</td>
<td>$MW$</td>
<td>Scheduled power exchange with other control areas,</td>
</tr>
<tr>
<td>$R_{\text{Req,Resup/dn,cap}}$</td>
<td>$MW$</td>
<td>Reserve capacity requirements of system operator,</td>
</tr>
<tr>
<td>$R_{\text{Req,Resup/dn,en}}$</td>
<td>$MWh$</td>
<td>Reserve energy requirements of system operator,</td>
</tr>
<tr>
<td>$\mu_{\text{ch}}$</td>
<td></td>
<td>Charging efficiency of storage,</td>
</tr>
<tr>
<td>$\mu_{\text{disch}}$</td>
<td></td>
<td>Discharging efficiency of storage,</td>
</tr>
<tr>
<td>$\omega_s$</td>
<td></td>
<td>Probability of considered reserve energy scenario,</td>
</tr>
</tbody>
</table>

Variables

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Units</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Symbol</td>
<td>Unit</td>
<td>Description</td>
</tr>
<tr>
<td>-------------------------------</td>
<td>--------</td>
<td>-----------------------------------------------------------------------------</td>
</tr>
<tr>
<td>$B_C^t$</td>
<td>m.u.</td>
<td>Benefit of coalition formation at time $t$,</td>
</tr>
<tr>
<td>$C_{\text{Stor}}^{j,t}$</td>
<td>m.u.</td>
<td>Cost of storage component in reserve capacity provision of consumer $j$ at time $t$,</td>
</tr>
<tr>
<td>$C_{\text{Resup}}^{j,t}$</td>
<td>m.u.</td>
<td>Cost of load shedding component in reserve capacity provision of consumer $j$ at time $t$,</td>
</tr>
<tr>
<td>$C_{\text{Resdn}}^{j,t}$</td>
<td>m.u.</td>
<td>Cost of load increasing component in reserve capacity provision of consumer $j$ at time $t$,</td>
</tr>
<tr>
<td>$C_{\text{Total}}^{j,t}$</td>
<td>m.u.</td>
<td>Cost of reserve capacity provision of consumer $j$ at time $t$,</td>
</tr>
<tr>
<td>$C_C^t$</td>
<td>m.u.</td>
<td>Cost of coalition formation at time $t$,</td>
</tr>
<tr>
<td>$\hat{C}_{\text{Resup/dn,cap}}^{j,t}$</td>
<td>m.u.</td>
<td>Estimated cost of reserve capacity provision of consumer $j$ at time $t$,</td>
</tr>
<tr>
<td>$D_{\text{En}}^{j,t}$</td>
<td>MWh</td>
<td>Scheduled energy consumption of consumer $j$ at time $t$,</td>
</tr>
<tr>
<td>$D_{\text{Resup/dn,cap}}^{j,t}$</td>
<td>MW</td>
<td>Scheduled up/down reserve capacity reservation of consumer $j$ at time $t$,</td>
</tr>
<tr>
<td>$D_{\text{Resup/dn,en}}^{j,\tau,s}$</td>
<td>MW</td>
<td>Scheduled up/down reserve energy provision of consumer $j$ at time $\tau$ in scenario $s$,</td>
</tr>
<tr>
<td>$D_{\text{Resup/dn,cap}}^{j,t,qu}$</td>
<td>MW</td>
<td>Scheduled up/down reserve capacity reservation in cost segment $qu$ of consumer $j$ at time $t$,</td>
</tr>
<tr>
<td>$D_{\text{Resup/dn,en}}^{j,\tau,e,s}$</td>
<td>MW</td>
<td>Scheduled up/down reserve energy provision of consumer $j$ at time $\tau$ in cost segment $e$ in scenario $s$,</td>
</tr>
<tr>
<td>$D_{\text{Resup/dn,en}}^{j,\tau,e,s}^*$</td>
<td>MW</td>
<td>Auxiliary variable for scheduled up/down reserve energy provision of consumer $j$ at time $\tau$ in cost segment $e$ in scenario $s$,</td>
</tr>
<tr>
<td>$D_{\text{Resup/dn,cap}}^{k,t}$</td>
<td>MW</td>
<td>Minimum requirements for up/down reserve capacity in contract proposal $k$ provided to consumer $j$ at time $t$,</td>
</tr>
<tr>
<td>$E_{\text{En}}^{j,\tau,s}$</td>
<td>MWh</td>
<td>Charging level of energy storage of consumer $j$ at time $\tau$ in scenario $s$,</td>
</tr>
<tr>
<td>$E_{\text{seg}}^{j,\tau,e}$</td>
<td>MWh</td>
<td>Charging level segment $e$ of energy storage of consumer $j$ at time $\tau$ in scenario $s$,</td>
</tr>
<tr>
<td>$G_{\text{En}}^{i,t}$</td>
<td>MWh</td>
<td>Scheduled energy production of generator $i$ at time $t$,</td>
</tr>
<tr>
<td>$G_{\text{Resup/dn,cap}}^{i,t}$</td>
<td>MW</td>
<td>Scheduled up/down reserve capacity reservation of generator $i$ at time $t$,</td>
</tr>
<tr>
<td>Symbol</td>
<td>Description</td>
<td></td>
</tr>
<tr>
<td>--------</td>
<td>---------------------------------------------------------------------------------------------------------------------------------------------</td>
<td></td>
</tr>
<tr>
<td>(G_{\text{Resup/dn,en}}^{i,\tau,s})</td>
<td>MWh Up/down reserve energy production of generator (i) at time (\tau) in scenario (s),</td>
<td></td>
</tr>
<tr>
<td>(p_{\text{Resup/dn,cap}}^{k,t})</td>
<td>m.u. Offered price for up/down reserve capacity in contract proposal (k) provided to consumer (j) at time (t),</td>
<td></td>
</tr>
<tr>
<td>(Q_{\bar{a},k})</td>
<td></td>
<td></td>
</tr>
<tr>
<td>(r_{\bar{a},k})</td>
<td>Q-value of action (a) chosen at learning round (k),</td>
<td></td>
</tr>
<tr>
<td>(u_{E}^{j,\tau,e,s})</td>
<td>MWh Binary variable for charging level (e) determination of energy storage of consumer (j) at time (\tau) in scenario (s),</td>
<td></td>
</tr>
<tr>
<td>(v_{G}^{i,\tau,s})</td>
<td>Auxiliary variable to differ between up/down reserve energy provision of generator (i) at time (\tau) in scenario (s),</td>
<td></td>
</tr>
<tr>
<td>(v_{D}^{j,\tau,s})</td>
<td>Auxiliary variable to differ between up/down reserve energy provision of consumer (j) at time (\tau) in scenario (s),</td>
<td></td>
</tr>
<tr>
<td>(x_j^{j,t})</td>
<td>MW Storage component in reserve capacity provision of consumer (j) at time (t),</td>
<td></td>
</tr>
<tr>
<td>(y_j^{j,t})</td>
<td>MW Load shedding component in reserve capacity provision of consumer (j) at time (t),</td>
<td></td>
</tr>
<tr>
<td>(z_j^{j,t})</td>
<td>MW Load increasing component in reserve capacity provision of consumer (j) at time (t),</td>
<td></td>
</tr>
<tr>
<td>(\Lambda_{\text{Resup/dn}}^t)</td>
<td>m.u. MWh Up/down reserve capacity price bid from aggregator at time (t),</td>
<td></td>
</tr>
<tr>
<td>(\Delta_{\text{Resup/dn}}^t)</td>
<td>MW Up/down reserve capacity quantity bid from aggregator at time (t),</td>
<td></td>
</tr>
<tr>
<td>(\Pi_{\text{Resup/dn}}^t)</td>
<td>m.u. Up/down reserve capacity price/quantity bid from aggregator at time (t),</td>
<td></td>
</tr>
<tr>
<td>(\alpha_{\text{Contr,Resup/dn,cap}}^t)</td>
<td>m.u. Intercept of linear relationship between price offer and minimum reserve requirements in contract proposals provided to consumers at time (t),</td>
<td></td>
</tr>
<tr>
<td>(\alpha_{\text{Resup,cap}}^b,t)</td>
<td>m.u. MW Offered price bid block (b) of aggregator for up reserve capacity in wholesale auction at time (t),</td>
<td></td>
</tr>
<tr>
<td>Symbol</td>
<td>Definition</td>
<td></td>
</tr>
<tr>
<td>-----------------</td>
<td>---------------------------------------------------------------------------</td>
<td></td>
</tr>
<tr>
<td>$\beta^{t}_{\text{Contr,Resup/dn,cap}}$</td>
<td>Slope of linear relationship between price offer and minimum reserve requirements in contract proposals provided to consumers at time $t$.</td>
<td></td>
</tr>
<tr>
<td>$\beta^{b,t}_{\text{Resdn,cap}}$</td>
<td>Offered price bid block $b$ of aggregator for down reserve capacity in wholesale auction at time $t$.</td>
<td></td>
</tr>
<tr>
<td>$\gamma^{b,\tau,s}_{\text{Resup,cap}}$</td>
<td>Offered price bid block $b$ of aggregator for up reserve energy in wholesale auction at time $\tau$ in scenario $s$.</td>
<td></td>
</tr>
<tr>
<td>$\delta^{b,\tau,s}_{\text{Resdn,cap}}$</td>
<td>Offered price bid block $b$ of aggregator for down reserve energy in wholesale auction at time $\tau$ in scenario $s$.</td>
<td></td>
</tr>
<tr>
<td>$\lambda^{t}_{\text{Resup/dn,cap}}$</td>
<td>Price of up/down reserve capacity at time $t$.</td>
<td></td>
</tr>
<tr>
<td>$\lambda^{\tau,s}_{\text{Resup/dn,en}}$</td>
<td>Price of up/down reserve energy at time $\tau$ in scenario $s$.</td>
<td></td>
</tr>
<tr>
<td>$\kappa^{j,t}_{\text{Resup/dn,cap}}$</td>
<td>Payments for reserve capacity from aggregator to consumer $j$ at time $t$.</td>
<td></td>
</tr>
<tr>
<td>$\kappa^{j,\tau,s}_{\text{Resup/dn,en}}$</td>
<td>Payments for reserve energy from aggregator to consumer $j$ at time $\tau$ in scenario $s$.</td>
<td></td>
</tr>
<tr>
<td>$\phi^{t}_{\text{Resup/dn,cap}}$</td>
<td>Coalition of consumers which provide up/down reserve capacity at time $t$.</td>
<td></td>
</tr>
<tr>
<td>$d \omega_s$</td>
<td>Weighting factor of scenario $s$.</td>
<td></td>
</tr>
</tbody>
</table>
# List of Figures

1.1 General setup power markets .................................. 2

2.1 Centralized electricity market ................................. 15
2.2 Private vs. Public goods ....................................... 18
2.3 Welfare effects of external reserve requirements ............ 19
2.4 Groves-Clarke revelation mechanism I ....................... 22
2.5 Groves-Clarke revelation mechanism II ....................... 23
2.6 Cost allocation for non-event based reserves ................. 26
2.7 Systems costs of reserves ..................................... 27
2.8 Systems costs of ramping ..................................... 29
2.9 Optimization of cost share .................................... 31
2.10 IEEE 9-bus test system ....................................... 36
2.11 Scheduling of energy .......................................... 36
2.12 Scheduling of reserves per time instant ...................... 37
2.13 Scheduling of reserves benchmark ............................ 38
2.14 Costs of abatement ........................................... 40
2.15 Scheduling of reserves/ramping costs R1/R2 ................. 41
2.16 Scheduling of reserves/ramping costs RR .................... 42

3.1 Cost allocation of support policies ............................ 46
3.2 Adaptive feed-in support ...................................... 49
3.3 Influence parameters .......................................... 53
### LIST OF FIGURES

<table>
<thead>
<tr>
<th>Figure</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.4</td>
<td>Probabilistic bounds</td>
<td>56</td>
</tr>
<tr>
<td>3.5</td>
<td>IEEE 24-bust test system</td>
<td>60</td>
</tr>
<tr>
<td>3.6</td>
<td>Scheduling of load and wind</td>
<td>61</td>
</tr>
<tr>
<td>3.7</td>
<td>Stated costs of abatement (low)</td>
<td>62</td>
</tr>
<tr>
<td>3.8</td>
<td>Stated costs of abatement (high)</td>
<td>62</td>
</tr>
<tr>
<td>3.9</td>
<td>Cost share load and wind</td>
<td>63</td>
</tr>
<tr>
<td>3.10</td>
<td>Revenue wind farm one wind site</td>
<td>64</td>
</tr>
<tr>
<td>3.11</td>
<td>Payment load one wind site</td>
<td>64</td>
</tr>
<tr>
<td>3.12</td>
<td>Wind farm W1 in case two wind sites</td>
<td>65</td>
</tr>
<tr>
<td>3.13</td>
<td>Load in case of two wind sites</td>
<td>65</td>
</tr>
<tr>
<td>3.14</td>
<td>Revenue change with scheduled reserves</td>
<td>66</td>
</tr>
<tr>
<td>4.1</td>
<td>Decentralized market framework</td>
<td>70</td>
</tr>
<tr>
<td>4.2</td>
<td>Proposed settlement procedure</td>
<td>73</td>
</tr>
<tr>
<td>4.3</td>
<td>IEEE 9-bus test system</td>
<td>78</td>
</tr>
<tr>
<td>4.4</td>
<td>Scheduling: no congestion case</td>
<td>79</td>
</tr>
<tr>
<td>4.5</td>
<td>Scheduling: congestion case</td>
<td>80</td>
</tr>
<tr>
<td>4.6</td>
<td>Cost recovery capacity whole time horizon</td>
<td>85</td>
</tr>
<tr>
<td>4.7</td>
<td>Cost recovery capacity every time instant</td>
<td>85</td>
</tr>
<tr>
<td>4.8</td>
<td>Highest stated demand curves of BRPs</td>
<td>87</td>
</tr>
<tr>
<td>4.9</td>
<td>Lowest stated demand curves of BRPs</td>
<td>87</td>
</tr>
<tr>
<td>4.10</td>
<td>Cost recovery for reserve capacity</td>
<td>88</td>
</tr>
<tr>
<td>4.11</td>
<td>Ratio BRP payments dependent upon elasticity of BRP</td>
<td>89</td>
</tr>
<tr>
<td>4.12</td>
<td>Total BRP payments in case of no congestion</td>
<td>90</td>
</tr>
<tr>
<td>4.13</td>
<td>Total BRP payments in case of congestion</td>
<td>91</td>
</tr>
<tr>
<td>6.1</td>
<td>Real-time pricing</td>
<td>102</td>
</tr>
<tr>
<td>6.2</td>
<td>Dynamics in real-time pricing</td>
<td>104</td>
</tr>
<tr>
<td>6.3</td>
<td>Individual bidding</td>
<td>105</td>
</tr>
<tr>
<td>6.4</td>
<td>Contract based reward</td>
<td>107</td>
</tr>
<tr>
<td>6.5</td>
<td>Control structure for AGC</td>
<td>110</td>
</tr>
<tr>
<td>6.6</td>
<td>Filtering of PI-controller output</td>
<td>111</td>
</tr>
<tr>
<td>Figure</td>
<td>Description</td>
<td>Page</td>
</tr>
<tr>
<td>--------</td>
<td>-----------------------------------------------------------------------------</td>
<td>------</td>
</tr>
<tr>
<td>6.7</td>
<td>Control signal: power vs. energy</td>
<td>114</td>
</tr>
<tr>
<td>7.1</td>
<td>Interaction of market participants</td>
<td>119</td>
</tr>
<tr>
<td>7.2</td>
<td>Contribution of consumers in AS provision</td>
<td>132</td>
</tr>
<tr>
<td>7.3</td>
<td>Exploitation/reward bilevel model</td>
<td>134</td>
</tr>
<tr>
<td>7.4</td>
<td>Payments with/without incentive compatibility</td>
<td>134</td>
</tr>
<tr>
<td>7.5</td>
<td>Exploitation in cooperative approach</td>
<td>135</td>
</tr>
<tr>
<td>7.6</td>
<td>Reward in cooperative approach</td>
<td>136</td>
</tr>
<tr>
<td>7.7</td>
<td>Cooperative approach dependent upon contracts</td>
<td>136</td>
</tr>
<tr>
<td>7.8</td>
<td>Illustration storage costs for AS</td>
<td>142</td>
</tr>
<tr>
<td>7.9</td>
<td>Exploitation capacity dependent upon storage</td>
<td>146</td>
</tr>
<tr>
<td>7.10</td>
<td>Exploitation energy dependent upon storage</td>
<td>147</td>
</tr>
<tr>
<td>7.11</td>
<td>Cost efficiency capacity dependent upon storage</td>
<td>147</td>
</tr>
<tr>
<td>7.12</td>
<td>Capacity exploitation dependent upon time</td>
<td>148</td>
</tr>
<tr>
<td>7.13</td>
<td>Cost efficiency capacity dependent upon time</td>
<td>149</td>
</tr>
<tr>
<td>7.14</td>
<td>Energy exploitation dependent upon time</td>
<td>149</td>
</tr>
<tr>
<td>7.15</td>
<td>Cost efficiency energy dependent upon time</td>
<td>150</td>
</tr>
<tr>
<td>B.1</td>
<td>Clarke-Groves non-event based reserves</td>
<td>173</td>
</tr>
<tr>
<td>B.2</td>
<td>Two-part pricing</td>
<td>183</td>
</tr>
</tbody>
</table>
## List of Tables

2.1 Incentive payments event-based reserves ................................. 43  
2.2 Incentive payments non event-based reserves ............................. 43  
3.1 Support policies ...................................................................... 47  
4.1 One-price settlement .................................................................. 82  
4.2 Two-price settlement .................................................................. 82  
4.3 Settlement based on price of imbalance energy ............................ 83  
4.4 Swiss imbalance settlement ....................................................... 83  
4.5 Payments for deployed energy benchmark approaches ................. 86  
6.1 Dominant frequency components ................................................. 112  
6.2 Confidence interval for limit of changes ...................................... 114  
6.3 Engineering/Economic pros and cons I ........................................ 116  
6.4 Engineering/Economic pros and cons II ...................................... 116  
7.1 Comparison of bilevel and cooperative approach ......................... 132  
A.1 Technical data generators chapter 2 .......................................... 159  
A.2 Economic data generators chapter 2 .......................................... 159  
A.3 Load data chapter 2 ................................................................... 159  
A.4 Abatement costs reserves and ramping chapter 2 ......................... 160  
A.5 Time series data load chapter 2 .................................................. 160
<table>
<thead>
<tr>
<th>Table Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>A.6 Line data chapter 2</td>
<td>160</td>
</tr>
<tr>
<td>A.7 Abatement cost reserves chapter 3</td>
<td>160</td>
</tr>
<tr>
<td>A.8 Generation data chapter 3</td>
<td>161</td>
</tr>
<tr>
<td>A.9 Generation data chapter 3 continued</td>
<td>162</td>
</tr>
<tr>
<td>A.10 Generation data chapter 3 continued</td>
<td>163</td>
</tr>
<tr>
<td>A.11 Generation data chapter 3</td>
<td>164</td>
</tr>
<tr>
<td>A.12 Generation data chapter 3 continued</td>
<td>165</td>
</tr>
<tr>
<td>A.13 Line data chapter 3</td>
<td>165</td>
</tr>
<tr>
<td>A.14 Technical data generator chapter 4</td>
<td>166</td>
</tr>
<tr>
<td>A.15 Economic data chapter 4</td>
<td>166</td>
</tr>
<tr>
<td>A.16 Economic data BRPs chapter 4</td>
<td>166</td>
</tr>
<tr>
<td>A.17 Data generator chapter 6</td>
<td>166</td>
</tr>
<tr>
<td>A.18 Data demand chapter 6</td>
<td>166</td>
</tr>
<tr>
<td>A.19 Learning data aggregator chapter 6</td>
<td>166</td>
</tr>
<tr>
<td>A.20 Contract proposal aggregator chapter 6</td>
<td>166</td>
</tr>
<tr>
<td>A.21 Time series data demand chapter 6</td>
<td>167</td>
</tr>
<tr>
<td>A.22 Technical data demand chapter 7</td>
<td>167</td>
</tr>
<tr>
<td>A.23 Economic data demand chapter 7</td>
<td>167</td>
</tr>
<tr>
<td>B.1 Test of Relaxation on 24-bus System</td>
<td>180</td>
</tr>
</tbody>
</table>
Chapter 1

Introduction

1.1 Background and Motivation

Since the late 1990’s the focus of electricity market design has shifted. The first phase of electricity market design literature dealt mainly with issues brought up through the liberalization of power markets. Market rules attempt to achieve several goals [1]:

- Create a balance between engineering issues such as reliable and secure physical operation and economic considerations with regards to spot and forward market pricing [2].
- Congestion management and a market setup for transmission property rights.
- Create long term planning functions and enable investments.

However, current electricity market designs have weak spots such as (a) the absence of the load’s willingness to adapt demand in times of supply scarcity, and (b) imperfect competition [3]. Furthermore, renewable energy generation, characterized by a low marginal cost structure and often prioritized feed-in, calls for progressions in market design. As essential part of spot markets, Day-Ahead Markets (DAM), Intra-Day Markets (IDM) and Ancillary Service Markets (ASM) can be distinguished [4]. Fig. 1.1 shows that the common property of spot market
Figure 1.1: General setup of spot power markets: First, in a day-ahead market the planning is realized. In the second phase, an IDM provides the possibility to make adjustment from the day-ahead schedule in order to minimize imbalances. In the last phase, another short term adjustment of demand and supply mismatch and the deployment of reserves at the point of physical delivery is possible.

designs is the minimization of imbalances at the time instant of physical delivery.

Ancillary Services (AS) include frequency support, voltage support and system restoration [5]. The focus of this thesis is ancillary service market design for frequency support. ASM designs for frequency support gain importance for several reasons: First, fluctuating energy feed-in in large scale will likely increase requirements for system services [6, 7]. Second, fluctuating energy feed-in in remote areas, in addition to market-based energy flows, may increase the occurrence of contingencies. Third, the role of demand side participation to support sufficient power system flexibility will increase [8]. ASM for frequency support includes several phases: The determination of the necessary amount of reserve capacity, the procurement by a Transmission System Operator (TSO) or an Independent System Operator (ISO), the deployment in case of mismatches at the time instant of physical delivery, and the financial settlement of costs for reserved capacity and deployed energy. Ref. [9], [10], and [11] summarize the current setups of major AS market-designs. Auction protocols and pricing mechanisms, which facilitate trade have been extensively discussed in the literature [12] and [13]. This thesis primarily deals with the last phase of the market design, namely financial settlement and allocation of costs.
In market design, it is the aim to ensure that market rules improve the overall "efficiency" of system operation, which at first means to compute an equilibrium that maximizes social welfare. Hence, spot market design focuses on "short-term efficiency". However, the transition between "short-term" and "long-term" efficiency is ambiguous. Moreover, in order to improve market designs, the term "efficiency" has to be carefully defined since it comes in several dimensions [1], [5], [14]:

1. **Efficiency in production**: It is desired to achieve the least cost mix of factor inputs to produce a commodity such as electricity.

2. **Efficiency in allocation**: It is desired that only those goods are produced which have the highest demand. In a competitive market framework the point of allocative efficiency is such that the marginal costs are equal to the market price.

3. **Dynamic efficiency**: This form of efficiency is tightly connected to the previous two. Short-term goals have to be compatible with long-term goals of a market. Given a well-functioning market design, this implies that in case of a change in the market conditions, production and allocation change such that they are again efficient.

Together, these notions of efficiency enable markets in the ideal case to fulfill the *First Fundamental Theorem of Welfare Economics* (FFTW) [14]:

"If every relevant good is traded in a market at publicly known prices, and if households and firms act perfectly competitively, then the market outcome is Pareto-Optimal. That is, when markets are complete, any competitive equilibrium is necessarily Pareto-Optimal."

An outcome is said to be Pareto-Optimal, if it is not possible to make some market participants better off in terms of welfare without making other individuals worse off. If market designs fail to achieve the previously mentioned levels of efficiency then the conclusion of FFTW is false. Special attention has to be paid to the requirement "if every relevant good is traded at publicly known prices". Dependent upon if an individual can be excluded from the consumption of a good, excludability, or if the consumption of the good interferes with the desires of other individuals, rivalry, an approximate differentiation can be made:
- **Standard Private Goods**, which are both excludable and rivalrous, i.e. food, or electricity as an input factor to produce certain services, and

- **Public Goods**, which are non-excludable (or only at high costs) and non-rivalrous, i.e. television, or reliable electricity supply.

Both of them, or some intermediate, have to be priced. Further, an externality, which occurs if the economic activity of one market participant (negatively) influences the economic goals of another one and therefore distorts the market outcome, has to be priced. In the course of this thesis, it is argued that Ancillary Service Market (ASM) should incorporate all these different elements. Without a proper pricing and, in case of public goods and externalities, an allocation of costs, market designs fail to reach efficiency. Particular examples of economic inefficiencies, which are dealt with in this thesis, are:

- Socialization of costs of AS.
- Transparent mechanisms for cost recovery of deployed AS.
- Missing market products for demand side participation in ASM.

Socialized costs do not take into account the individual valuation of reliable electricity supply and therefore do not provide incentives for reducing the need for reserves. Furthermore, a market-like integration of costs of Renewable Energy Sources (RES), and Demand Response (DR) involves that fluctuating injection and demand take over responsibility to remain an announced schedule. Finally, externally set requirements for reserves by the system operator provide the opportunity for generators to abuse market power.

In the first part of the thesis, the aim is the improvement of the efficiency in the allocation of Ancillary Services (AS) costs. Since, reliable and secure electricity supply and thus AS are a kind of a public good it is desirable that market entities, which distort a competitive market outcome, are faced with the true costs of reliable and secure electricity supply and thus reveal their preferences on reliable electricity supply. In other words, financial incentives for a) decentralized efforts for a market-based integration of renewable energy, and b) demand side participation are created. A market-like determination of reserves leads simultaneously to more efficiency in production since the reserve requirements are dependent upon a price and are elastic.
1.2. Main Contributions of this Thesis

The second part of the thesis deals with the inefficiency of a missing market framework on a retail level to enable demand side participation for ancillary services. DR refers to the willingness of the consumer to respond to prices of electricity, or to receive incentive payments in times where grid security is jeopardized [15]. The aim of this part is the establishment of a rewarding scheme for consumers to (a) provide an additional source of power system flexibility, and (b) to increase backup capacity for ancillary services [16]. A contract-based perspective is taken, which enables incentive-based payments to reward loads for participation in ASM. Incentive-based means that participants are willing to reveal their true preferences about a market product.

The thesis uses different methods to describe the previously discussed issues. Reference [17] points out the still ongoing trend of using optimization, equilibrium and simulation models in electricity market design. Optimization problems offer the advantage of stochastic modeling. Equilibrium models explicitly try to take multi-agent behavior in a mathematical framework into account. Common approaches are Cournot and supply function equilibria models (e.g. [18], [19] and [20]). Ref. [21] takes the bidding of rival producers by bilevel optimization into account. Ref. [22] and [23] outline the broad field of the application of agent-based modeling frameworks in power systems, which are one possible form of simulation based modeling.

1.2 Main Contributions of this Thesis

This dissertation presents in its first part,

- a mechanism to efficiently allocate costs of reserve capacity and ramping services, which are necessary to keep the system balanced. The mechanism setup is presented on a day-ahead planning basis in the course of a centrally organized power system with an ISO as coordinating entity between market operation and duties of system security. Two methods are presented, where one of them involves robustness against mispresentation of preferences of market participants for reliable electricity supply.

- an application of the proposed cost allocation methodology to achieve higher cost efficiency in supporting renewable energy injection.
• an imbalance settlement mechanism which enables efficient allocation and recovery of costs of reserve capacity and deployed energy in system setup, where the market operation is separated from duties of system security. A comparison with existing imbalance settlement schemes is done.

The second part of the thesis deals with the issues of rewarding demand side participation in ancillary service markets through,

• a qualitative comparison of market-based approaches for achieving higher demand side participation for ancillary service markets.

• the assessment of the role of information in two different methods for contract-based rewards. Reward contracts have to be incentive compatible, which means that the consumers voluntarily reveal their true costs of providing system services.

• the assessment of the role of physical parameters such as storage capacity on the design of contracts.

1.3 Thesis Outline

The thesis is divided into the following chapters:

Chapter II, Cost Allocation in a Centrally Operated Systems, presents the economic mechanisms which are applied to achieve an efficient allocation of balancing costs in a power system.

Chapter III, Performance Based Renewable Energy Support, highlights one application of the mechanisms, presented in Chapter II and presents an adaptive feed-in support, which may enhances a cost-efficient spread of renewable energy sources.

Chapter IV, Cost Allocation in a Decentralized System, extends the range of incentive-based market mechanisms for ancillary services presented in Chapter II. It deals with the issue of cost recovery for ancillary services in a power system setup where the duties of system security are separated from market operation.
Chapter V, Closure Part I, gives conclusions and a perspective for future research for the first part of the thesis.

Chapter VI, Market-like Incorporation of Demand Response, discusses key issues and possible market approaches for the incorporation of demand response in ancillary service markets. On a qualitative basis the advantages of a contract-based setup with direct load control are highlighted.

Chapter VII, Design of Contract-based Rewards, deals with two different approaches to model demand response markets. Both approaches assume an intermediary entity, commonly referred to as aggregator, which acts between the retail level and wholesale electricity markets. However, whereas in the first approach the intermediary is seen as a third-party entity with the aim of profit maximization, it is in the second approach a coordinating entity in a cooperative of consumers aiming for participation in electricity markets.

Chapter VIII, Closure Part II, gives conclusions and a perspective for future research for the second part of the thesis.

Appendix, System data and method details are presented in the appendix.

1.4 List of Publications

The following authored and co-authored papers directly relate to the contents of the thesis:


The contents of the following authored and co-authored papers are not directly related with the thesis, but address related topics:


Chapter 1. Introduction
Part I

Allocation of Balancing Responsibility
Chapter 2

Cost Allocation in a Centrally Operated Systems

Omnium Rerum Principia Parva Sunt - The beginnings of all things are small. M. T. Cicero, De Finibus Bonorum et Malorum, Book V, Chapter 58

Market designs for ancillary services should ensure productive efficiency and efficiency in the allocation of costs. This chapter deals with the allocation of ancillary service costs and financial incentives for decentralized balancing efforts. First, the basic economic concept for allocating costs of ancillary services are introduced. Second, in the course of non-linear optimization, the sensitivity of the proposed framework with respect to design parameters, such as the amount of reserve requirements and stated cost curves for avoiding deviations from the schedule, is assessed. This chapter is based on [24] and [25].

2.1 Introduction and Motivation

In current power market designs the costs of procured reserves and renewable energy feed-in are primarily allocated based on administrative
Chapter 2. Centrally Operated System

rules, i.e. system-wide socialization. As highlighted in the introduction, a rigid ASM design in terms of procurement of reserves and allocation of cost involves disadvantages in short-term and long-term goals of electricity markets:

1. It does not provide financial incentives in the short-term to de-centrally avoid the occurrence of deviations from the schedule. Hence, it decreases financial incentives for demand response programs and market-based integration of renewable energy feed-in.

2. It enables strategic behavior through inelastic demand of reserves capacity due to scarcity conditions on the supply side or limited transmission capacity.

Economic theory suggests to price contingency services like reliable electricity supply based on the individual valuation of it [26]. Further, the allocation of costs of system services is in general not based on cost-by-cause principles. In this chapter, the focus lies on centralized markets. As shown in Fig. 2.1, the main feature of a centralized setting is that market operation and duties of system security are merged into one entity, i.e. the Independent System Operator (ISO).

The definitions of ancillary service products differ across ASM [10, 11]. Throughout the thesis, the following terminology is used:

- **Non event-based reserves**: This type of reserves ensures frequency containment in normal operation, i.e. regulating reserves and ramping services.

- **Event-based reserves**: This type of reserves compensates power plant outages or line outages and contributes to frequency restoration in case of major disruptions, i.e. contingency reserves.

Due to the drawbacks of an inefficient allocation of costs of reserves and ramping services, an ASM framework is proposed which comprises:

1. A market-based allocation of the procurement costs for event-based reserves. For this purpose, the existence of an elastic demand curve for event-based reserves and the incorporation of a locational component is assumed in [26], [27] and [28]. The elasticity of demand for reserve capacity represents an individual valuation of reliable electricity supply. The auction design for event-based reserves requires a special economic method since security
2.2 Literature Review

in power systems can be seen as a public good with aspects of non-rivalry and non-excludeability [29].

2. A market-based allocation of procurement costs for non event-based reserves. These costs are evaluated by assessing the system-wide costs that are incurred by holding reserves and comparison with the costs of avoiding reserve requirements. This approach is similar to the theory of pricing an externality, where the activity of a market participant influences the economic goals of another one, and therefore distorts the market outcome [30]. In this chapter, it is assumed that distorting market participants are primarily characterized by fluctuating demand.

Figure 2.1: An auction process of a typical centrally organized electricity market: The system operator collects relevant market data from load serving entities and generators and proceeds with a security constrained maximization of social welfare. Ancillary services may also be simultaneously optimized. As a result, locational prices and prices for ancillary services are published.

2.2 Literature Review

According to the rules by the European Network of Transmission System Operators for Electricity (ENTSO-E), the demand for event-based reserves depends on the forecasted load level or the largest blocks in operation in the control areas [31]. Some European system operators also consider load uncertainty and renewable feed-in deviations via fixed quantiles from an empiric distribution function derived from historic
forecast errors for non event-based reserve capacity determination [4]. However, the reserve demand determined is inelastic. The procurement costs do not refer to the individual valuation of it, or to the degree of utilization of the grid. Ref. [32], [33] and [34] determine an elastic demand for spinning reserves via a cost/benefit analysis. For example, ref. [32] established a demand curve for spinning reserves via the concept of Expected Energy Not Served (EENS) and a constant Value Of Lost Load (VOLL). The value of the EENS results from the generation schedule with the corresponding Capacity Outage Probability Table (COPT) [35]. Ref. [33] established an elastic demand curve for secondary frequency control reserves by taking into account the probabilistic nature of contingencies and their impact with regards to different cost factors, i.e. costs of frequency deviations. Further, the costs are associated to automatic load shedding, and the costs associated with deviations over the scheduled power exchange. All approaches did not analyse the proper cost allocation of procured reserve capacity. Ref. [36] and [37] address the allocation of costs for procured event, and non event-based reserves. The established metric for cost assignment is based on the analysis of historic data. The model presented in this chapter provides an economically efficient mechanism to allocate costs of system services by means of non-linear optimization.

2.3 Modelling Framework

2.3.1 Cost Allocation of Event-Based Reserves

It is assumed that the individual demand for event-based reserves is decoupled from the amount of energy consumed, since they are from an economic point of view no perfect substitutes [38]. This makes an analysis in terms of cost allocation possible. As stated in the literature review, elastic demand curves for non event-based reserves have already been derived by ref. [32], [33], [34], and [39] and are assumed to be known. The operating points and the elasticities of the demand curves are subject to the effort of the system operator or utility to arrange interruptible load contracts, and the physical capabilities of the demand [40], [41].

Event-based reserves, i.e. contingency reserves, are needed for events which occur, usually with low probability. Therefore these kind of events are hard to predict and even with high cost effort never completely
preventable. Consumers were therefore assumed to have preferences about the amount of reserves they would like to have as backup capacity. The demand curve for event-based reserves is assumed to be of the form:

\[
MB_{\text{Resup/dn}}^{\text{evt,j,t}} = \left( \frac{Q_{\text{Resup/dn}}^{\text{evt,j,t}}}{F_{\text{Resup/dn}}^{\text{evt,j,t}}} \right)^{\epsilon_{\text{Resup/dn}}^{\text{evt,j,t}}},
\]

where \( \epsilon_{\text{Resup/dn}}^{\text{evt,j,t}} = \frac{1}{\eta_{\text{Resup/dn}}^{\text{evt,j,t}}} \) and \( \eta_{\text{Resup/dn}}^{\text{evt,j,t}} \in ]-\infty, 0] \). \( MB_{\text{Resup/dn}}^{\text{evt,j,t}} \) is the marginal benefit of up/down event-based reserve capacity of consumer \( j \) at time \( t \), \( F_{\text{Resup/dn}}^{\text{evt,j,t}} \) is a positive factor, \( \eta_{\text{Resup/dn}}^{\text{evt,j,t}} \) is the elasticity of demand for event-based reserves, and \( Q_{\text{Resup/dn}}^{\text{evt,j,t}} \) is the amount of reserve capacity demanded at time instant \( t \). Generally, also other non-linear benefit curves are possible, e.g. a quadratic benefit. The choice is part of further research and is out of the scope of this thesis. This form has been chosen because it shows characteristics of a quadratic curve, but only has two tuning parameters.

The total demand of event-based reserves capacity is established in two steps: First, the individual demand curves for reserves as shown in Fig. 2.2a are ”vertically” aggregated, which differs from the ”horizontal” aggregation of demand, as shown in Fig. 2.2b, for private goods like traded energy. The established market clearing is called a Lindahl equilibrium and enables the allocation of cost in case of a public good [29], [42]. The equilibrium in Fig. 2.2a enables the determination of price shares, \( \lambda_{\text{Resup/dn,cap}}^{\text{evt,1}} \) and \( \lambda_{\text{Resup/dn,cap}}^{\text{evt,2}} \), for the procured public good dependent upon the individual valuation of it. In the case of marginal pricing in Fig. 2.2b, which is common for the market clearing for private goods, such a cost sharing is not possible.

However, applying the Lindahl equilibrium to allocate costs of public services creates incentives for a mispresentation of the demand for event-based reserves in order to save costs. This gaming behavior may lead to operational security problem, as insufficient reserves are procured in a market based solution.
Figure 2.2: Market clearing for public and private goods and constant marginal costs of supply, $MC$.
(a) Public good clearing: The demand curves $MB_{\text{Resup/dn}}^{evt,1}$ and $MB_{\text{Resup/dn}}^{evt,2}$ are added "vertically" to $\overline{MB_{\text{Resup/dn}}^{evt,*}}$ in order to achieve a Lindahl equilibrium $(\lambda_{\text{Resup/dn}}^{evt,*}, D_{\text{Resup/dn}}^{evt,*})$. The individual price shares, $\lambda_{\text{Resup/dn}}^{evt,2}$ and $\lambda_{\text{Resup/dn}}^{evt,2}$, are in accordance with the individual preferences for the public good $MB_{\text{Resup/dn}}^{evt,1}$ and $MB_{\text{Resup/dn}}^{evt,2}$.
(b) Private good market clearing: The demand curves $MB_{\text{Resup/dn}}^{evt,1}$ and $MB_{\text{Resup/dn}}^{evt,2}$ are added "horizontally" to $\overline{MB_{\text{Resup/dn}}^{evt,**}}$ in order to achieve a competitive equilibrium $(\lambda_{\text{Resup/dn}}^{evt,**}, D_{\text{Resup/dn}}^{evt,**})$. 
2.3. Modelling Framework

Two countermeasures can be set:

1. Minimum reserve requirements are set by the system operator, which ensure that a market-based clearing of reserve capacity does not threaten system security. However, setting limits on the amount of event-based reserve capacity may create inefficiencies as seen in Fig. 2.3: On the one hand, setting too high security requirements destroys market-based incentive mechanisms and creates a surplus loss. On the other hand, too low requirements may do not guarantee system security at all, which includes the loss of social welfare containing parts of the total consumer surplus ($CS$), and producer surplus ($PS$). Hence, the marginal benefit of externally set additional reserve requirements changes from zero to a very high value.

2. A preference revealing mechanism, which ensures that market participants always state their true demand for reserves.

![Diagram](image)

Figure 2.3: In case of an elastic demand curve for event-based reserve capacity, a market clearing ($D^*_{evt, Resup/dn}, \lambda^*_{Resup/dn}$) can be established. The consumer surplus, $CS$, of sufficient supply with reserves is determined by $GEF$, the producer surplus, $PS$, is determined by $EFH$. A market-based solution may not be always feasible in daily operation. Therefore it may be necessary to ensure minimal security requirements in case too low amounts of reserve capacity are contracted, $D^*_{evt, Resup/dn}$. However, too high or too low externally imposed security standards, $D^*_{evt, Resup/dn}$ and $D^*_{Resup/dn}$, eventually create welfare losses of $SL_A$ and $SL_B$.

Referring to the latter option, a preference revealing mechanism, specifically the Clarke-Groves mechanism, is proposed [43]. The mechanism
applied to the cost allocation problem for event-based reserves is illustrated in Fig. 2.4a-2.5b. A general formal motivation is given in the appendix B.1.1. Fig. 2.4a shows that the demand curve for event-driven reserves of $N_L$ loads are aggregated to $MB_{Resup/dn}^{evt}$. The intersection with the supply curve, $MC$, results in $λ_{Resup/dn}^{evt,*}D_{Resup/dn}^{evt,*}$. The demand curve $MB_{Resup/dn}^{evt,min1}$ represents the sum of demand curves excluding individual $j$ with demand $MB_{Resup/dn}^{evt,j}$. If individual $j$ has in the Clarke-Groves framework no preferences for reserve capacity, then no payments occur at point $A$. If the individual demands a certain amount of reserve capacity, e.g. from $D_{Resup/dn}^{evt,1}$ to $D_{Resup/dn}^{evt,2}$, then a marginal compensation of $\int_{D_{Resup/dn}^{evt,1}}^{D_{Resup/dn}^{evt,2}} SS$ for the additional costs which are caused to the other individuals has to be paid. The largest possible surplus for the individual for stating the preferences for the public good comprises the area $ACE$.

Fig. 2.4b shows the case of preference mispresentation by individual $j$. It is shown that the individual loses the surplus $CHG$ in case of stating a too low demand for event-based reserves, $MB_{Resup/dn}^{evt,j'}$. Fig. 2.5a shows the welfare incident of the proposed preference revealing mechanism. The Clarke-Groves tax, $Ar_C$, is the incentive based part of the payments and represents the costs that the individual imposes on other market participants by consuming the public good. Area $Ar_B$ represents the benefit of the individual from consuming the public good. If the individual mispresents its preferences, i.e. by stating a lower marginal benefit by consuming the public good, it is losing welfare. Area $Ar_A$ has the purpose to ensure overall revenue sufficiency for covering the costs of reserves. In order to ensure revenue sufficiency and to avoid that loads can influence the amount of payments, a randomized cost sharing method can be chosen:

$$Ar_A = \sum_j p_j MB_{Resup/dn}^{evt,min1} (D_{Resup/dn}^{evt}),$$  \hspace{1cm} (2.2)

where $\sum_j p_j = 1$ and,

$$p_j \sim U(LB, UB), \forall j.$$ \hspace{1cm} (2.3)

$MB_{Resup/dn}^{evt,min1} (D_{Resup/dn}^{evt})$ is the benefit curve when the demand curve of individual $j$ is removed. For $D$ the interval $[0, D_{Resup/dn}^{evt,1}]$ is assumed
2.3. Modelling Framework

(see also Fig. 2.5a). The weighting factor $p^j$ is drawn from a uniform distribution, where the lower bound, $LB$, and the upper bound, $UB$, are determined by the system operator. The determination should take into consideration that excessive payments to the system operator have to be avoided and therefore may require regulatory observation. Due to a revenue sufficiency part, $Ar_A$, this preference revelation mechanism may charge loads more than necessary to recover balancing energy costs. A mechanism which shows this characteristic is generally referred to as not being budget balanced. Hence, the excess payments have to be redistributed again, which probably lowers the efficiency of the algorithm in terms of preference revelation. An appropriate subsequent redistribution algorithm is out of the scope of this thesis. Finally, the Clarke-Groves incentive based payment, $Ar_C$, is only non-zero as long as the preference of the individual has an influence on the market outcome. Thus, an aggregation of loads with similar preferences for system services is necessary, which is able to influence the market outcome in order to achieve incentive-based payments greater than zero.

Fig. 2.5b shows the case when a market-based clearing of supply and demand for event-based reserves is below an externally set security minimum. Excess costs are forwarded randomly on the market participants via a randomized sharing rule similar to eq. (2.2). This ensures that market participants are not tempted to influence the market clearing and to take advantage of possible arbitrage between socialized costs and individually imposed costs, especially in the border-line case when the market outcome is close to the externally set security minimum.

In total $NL + 1$ optimization problems are solved in order to establish market clearing prices for the generators, and to engage loads to reveal their reliability preferences truthfully. Alternative preference revelation mechanisms are conceivable, but not treated in this thesis.
Figure 2.4: Preference revelation via Clarke-Groves-Mechanism: (a) Starting from the case of no preference for the public good $D_1$, the individual consumer has to pay the marginal compensation of $\int_{D_{\text{Resup/dn}}}^{D_{\text{evt,1}}\text{Resup/dn}} SS = ABC$ for the provision of the public good. The welfare is marked by $ACE$. (b) In case of mispresentation of preferences the consumer looses welfare of $GCH$. 
2.3. Modelling Framework

Figure 2.5: Preference revelation via Clarke-Groves-Mechanism:
(a) The individual gets charged the area $\text{Area}_A$ and $\text{Area}_C$, where size of $\text{Area}_C$ shouldn’t be influenced the action of the respective demand curve and has the purpose to ensure revenue sufficiency for the TSO. $\text{Area}_B$ represents the benefit of the BRP of consuming the public good.

(b) Additional costs, $\text{Area}_{\text{ext}}$, due to high externally set minimal security requirements, $D_{\text{Resup}/dn}^{\text{ext,ext}}$, have to be socialized such that an individual market participant cannot influence the market outcome and create arbitrage effects.
Chapter 2. Centrally Operated System

2.3.2 Cost Allocation of Non Event-Based Reserves

Individual Cost Curve for Non-Event-Based Reserve Capacity

The requirements for non event-based reserves are driven by fluctuations in power injections and extractions. The residual demand of load \( j \) (demand minus non-controllable injection), \( D_{En}^{j,t} \), is decomposed as follows:

\[
D_{En}^{j,t} = D_{d,En}^{j,t} + \tilde{D}_{En}^{j,t},
\]

where \( D_{d,En}^{j,t} \) is the hourly deterministic component of the net consumption of load \( j \) at time \( t \) and \( \tilde{D}_{En}^{j,t} \) is a forecasting error, i.e. a random deviation.

The method of cost allocation for non event-based reserves and ramping efforts differs from the one for event-based reserves. In case of non event-based reserves, it is assumed that demand units or fluctuating injection have the capability of reducing their stochastic component for certain costs. As shown in Fig. 2.6a, the amount of reserves necessary to cover imbalances from fluctuating sources can be reduced to a social optimal outcome if the marginal costs of avoiding imbalances and excessive ramping events are equal to the marginal system costs of providing these services [30]. The equilibrium in Fig. 2.6a is defined by a "clearing quantity", \( \tilde{D}_{Resup/dn}^{noevt,*} \) and a "clearing price", \( \lambda_{Resup/dn}^{noevt,*} \). \( \tilde{D}_{Resup/dn}^{noevt,*} \) states the optimal amount of unscheduled deviations, which have to be covered by reserves provided by the system operator. In case of ramping services, the equilibrium represents the optimal share of ramping efforts which have to be undertaken by conventional generators and by the market participants with fast changes in their net consumption. \( \lambda_{Resup/dn}^{noevt,*} \) may be interpreted as a tax on suboptimal feed-in/demand behavior. It is assumed that the marginal costs of demand \( j \) for avoiding neg./pos. imbalances from the schedule, \( Q_{Resup/Resdn,ab}^{noevt,j,t} \), are of the form:

\[
MC_{Resup/dn,ab}^{noevt,j,t} = \left( \frac{Q_{Resup/dn,ab}^{noevt,j,t}}{F_{Resup/dn,ab}^{noevt,j,t}} \right) \epsilon_{Resup/dn,ab}^{noevt,j,t},
\]

where \( \epsilon_{Resup/dn,ab}^{noevt,j,t} = \frac{1}{\eta_{Resup/dn,ab}^{noevt,j,t}} \). \( F_{Resup/dn,ab}^{noevt,j,t} \) is a positive factor, \( \eta_{Resup/dn,ab}^{noevt,j,t} \in [0, \infty] \) is the elasticity of supply for abating deviations,
2.3. Modelling Framework

\( MC_{\text{Resup/dn,ab}}^{\text{noevt,j,t}} \) is the marginal costs of abatement for centrally procured up/down non event-based reserve capacity by participant \( j \), and \( Q_{\text{Resup/dn,ab}}^{\text{noevt,j,t}} \) is the abated amount of non event-based reserves at time instant \( t \). Only the resulting fluctuations are relevant in a pooled system, which is valid in case of one market participant who creates negative market externalities such as unscheduled deviations as shown in Fig. 2.6a. However, scheduled non event-based reserves are also a public good. Therefore, as shown in Fig. 2.6b, a market design that determines the cost shares of individuals for the provision of a public good is proposed. The concept shown in Fig. 2.6b includes the aspects of efficient cost allocation in presence of public goods discussed in section 2.3.1.

System Cost Curve for Non Event-Based Reserve Capacity

A decisive parameter in the proposed method is the amount of reserves scheduled by the system operator assuming that no balancing efforts are undertaken by the market participants. There exists a rich literature on the determination of the amount of non event-based reserves demanded by the system operator in case of no decentralized balancing efforts. Due to a possible intra-day market operation, the amount of reserves needed is not only determined by the analysis of day-ahead forecast deviations. In this chapter, for the sake of simplicity, it is assumed to be an external parameter. Further, in order to keep parameters of freedom low, we consider equal requirements for up and down reserve capacity \( R_{\text{Req,}c}^{\text{noevt,t}} \), where

\[
R_{\text{Req,}c}^{\text{noevt,t}} = [R_{\text{Req,Resup,c}}^{\text{noevt,t}}, R_{\text{Req,Resdn,c}}^{\text{noevt,t}}]^+. \tag{2.6}
\]

In order to determine the costs of different levels of reserve requirements the system operator has to hold, a cost curve is established using an iterative procedure as shown in Fig. 2.7a. Reserve requirements are increased from the point where the exclusion of one cost curve of abatement has the highest impact, to the point where the aggregated cost curves of abatement is in place. Fig. 2.6b shows that the advantage of this procedure is that only a certain part of the cost curve has to be determined. The costs comprise the costs of procured reserve capacity plus the opportunity costs of generators. The proposed procedure for determining the incentive payments in a Clarke-Groves setting for the externality problem as shown in Fig. 2.6 is illustrated in appendix B.1.3.
Figure 2.6: Cost allocation for non event-driven reserves:
(a) In case of an equilibrium point \( \tilde{D}_{\text{Resup/dn}}^{\text{noevt}}, \lambda_{\text{Resup/dn}}^{\text{noevt},*} \) and competitive market conditions, the total cost \( C_{\text{noevt}}^{\text{abate}} + C_{\text{sys}}^{\text{noevt}} \) is a minimum. In case of competitive markets, the producer will reveal his true marginal costs.
(b) In case several market entities causing externalities (wind feed-in and demand) which influence the amount of non event-driven reserves, the equilibrium is achieved via vertical addition of \( MC_{\text{Resup/dn,ab}}^{\text{noevt},1} \) and \( MC_{\text{Resup/dn,ab}}^{\text{noevt},2} \). \( \lambda_{\text{Resup/dn}}^{\text{noevt},*} \) is shared according to the stated marginal abatement curves of the market participant \( (MC_{\text{Resup/dn,ab}}^{\text{noevt},1}) \) and \( (MC_{\text{Resup/dn,ab}}^{\text{noevt},2}) \). Therefore preference revelation incentives will be necessary.
2.3. Modelling Framework

2.3.3 Cost Allocation of Ramping Services

The costs of ramping have been treated in literature in several ways [44], [45], and [46]. The approach of ref. [44] is generalized to distinguish costs for up ramping operation from costs for down ramping operation:

\[ C^i_{\text{Ramp}} = C^i_{\text{Rup}} \sum_{t=1}^{N_T} EP^i_{\text{Rup}} + C^i_{\text{Rdn}} \sum_{t=1}^{N_T} EP^i_{\text{Rdn}}. \]  

(2.7)

Parameter \( C^i_{\text{Rup/Rdn}} \) is the cost of ramping for generator \( i \), and \( EP^i_{\text{Rup/Rdn}} \) is the energy content of up/down ramping of generator \( i \) at time \( t \):

\[ EP^i_{\text{Rup}} = \frac{\tau^i_{\text{Rup}}}{2GR^i_{\text{Rup}}} (G^i_{\text{En}} + G^{i,t-1}_{\text{En}}), \]  

(2.8)

\[ EP^i_{\text{Rdn}} = \frac{\tau^i_{\text{Rdn}}}{2GR^i_{\text{Rdn}}} (G^{i,t-1}_{\text{En}} + G^{i,t}_{\text{En}}), \]  

(2.9)

where \( GR^i_{\text{Rup/Rdn}} \) is the ramp rate of unit \( i \) at time \( t \). This value may be dependent upon the operating point of the generation unit. Variable \( G^i_{\text{En}} \) is the generation of unit \( i \) at time \( t \). Variable \( \tau^i_{\text{Rup/Rdn}} \) is the time
duration of the up/down ramping:

\[
\tau_{i,t}^{\text{Rup}} = \max(0, G_{i,t}^{i,t} - G_{i,t}^{i,t-1}) \frac{G_{Rup}^{i,t}}{G_{Rup}^{i,t}}, \tag{2.10}
\]

\[
\tau_{i,t}^{\text{Rdn}} = \max(0, G_{i,t}^{i,t-1} - G_{i,t}^{i,t}) \frac{G_{Rdn}^{i,t}}{G_{Rdn}^{i,t}}, \tag{2.11}
\]

For the consideration of ramping costs, the system energy balance has to be considered:

\[
\sum_{i=1}^{N_G} E_{i,t} = \tau \left\{ \left( \sum_{j=1}^{N_L} D_{j,t} \right) + P_{Rup,ab}^t - P_{Rdn,ab}^t \right\}, \tag{2.12}
\]

where \(E_{i,t}\) is the total energy production of generating unit \(i\) at time \(t\):

\[
E_{i,t} = ER_{Rup}^{i,t} + ER_{Rdn}^{i,t} + (\tau - \tau_{i,t}^{\text{Rup}} - \tau_{i,t}^{\text{Rdn}})G_{En}^{i,t}. \tag{2.13}
\]

Finally, up and down shifting of energy cannot be done simultaneously

\[
P_{Rup,ab}^t \geq 0, \quad P_{Rdn,ab}^t \leq \omega_{Rupdn}^j M, \]

\[
P_{Rdn,ab}^t \geq 0, \quad P_{Rup,ab}^t \leq (1 - \omega_{Rupdn}^j) M,
\]

where \(\omega_{Rupdn}^j \in [0, 1]\) is a binary auxiliary decision variable, and \(M\) is a large constant. Further, it is required that the energy shifted for ramping requirements is netted out over a specific time horizon:

\[
0 = \sum_{t=1}^{N_T} \tau (P_{Rup,ab}^t - P_{Rdn,ab}^t). \tag{2.14}
\]

\(P_{Rup/Rdn,ab}\) is the up/down shift of consumption or production by market participants over the optimization horizon.

**Individual Costs of Ramping Effort Abatement**

The marginal costs of shifting demand and production in order to reduce up/down ramping requirements are modeled as,

\[
MC_{Rup/Rdn,ab}^{j,t} = \left( \frac{Q_{Rup/Rdn,ab}^{j,t}}{F_{Rup/Rdn,ab}^{j,t}} \right) \frac{\epsilon_{Rup/Rdn,ab}^{j,t}}{\epsilon_{Rup/Rdn,ab}^{j,t}}, \tag{2.15}
\]
where \( \epsilon_{Rup/Rdn,ab}^{j,t} = \frac{1}{\eta_{Rup/Rdn,ab}^{j,t}} \). \( F_{Rup/Rdn,ab}^{j,t} \) is a positive factor and \( \eta_{Rup/Rdn,ab}^{j,t} \in [0, \infty[ \) is the elasticity of supply for abating excessive ramping and \( Q_{Rup/Rdn,ab}^{j,t} \) is the amount of energy shifted by the demand and the fluctuating injections in order to reduce ramping requirements at time \( t \).

**System Cost Curve of Ramping Effort**

System costs of ramping are determined using eqs. (2.7)-(2.14). The iterative procedure, illustrated in Fig. 2.8, starts from a schedule which serves the median demand of the whole day and then increases iteratively the ramping efforts up to the original schedule.

![System Cost Curve of Ramping Effort](image)

Figure 2.8: Iterative procedure to determine system costs of ramping: Starting from the median of the total demand over the day, \( D^{Med}_{En} \), the ramping requirements are increased in every iteration round \( (n_1, n_2, ..., n_x) \) up to \( n_x \) rounds.

**2.3.4 Non-Linear Optimization**

As shown in Fig. 2.9, the determination of the share of balancing responsibility is done in three steps:

1. In the course of a unit commitment problem, locational marginal prices (LMPs) are determined. Further, ramp rates of the generation units are determined following [45].

2. A co-optimization problem is solved, which clears the market for both, traded energy and reserves. In order to determine the lost opportunity costs of providing reserves, the LMPs from the
energy-only unit commitment problem are used. The ramp rates for the determination of ramping costs are fixed in this problem to the values from the energy-only problem.

3. The previously presented cost allocation mechanism is applied.

In order to determine the incentive payments for preference revelation, further steps are necessary:

1. The optimization problem (2.18)-(2.20) has to be solved $N_L$ times in order to determine the quantities abated if one demand unit is removed.

2. In order to apply a preference revelation mechanism the system costs of non event-based reserves and ramping have to be approximately reconstructed using the iterative procedures described in sections 2.3.2 and 2.3.3.

Energy-Only Unit Commitment

The energy-only market is modeled using piece-wise constant marginal costs from the generators and assumes a fixed demand [47, 48]:

$$
\max_{\vartheta_1} \sum_{t=1}^{N_T} \left\{ - \sum_{i=1}^{N_G} (u^{i,t} C_{noload}^{i,t} + C_{Start}^{i,t}) - \sum_{i=1}^{N_G} \sum_{s=1}^{N_S} MC_{En,seg}^{i,s,t} G_{En,seg}^{i,s,t} \right\},
$$

subject to

$$
\begin{align*}
    h_1(a, x, u) &= 0, \\
    g_1(a, x, u) &\leq 0,
\end{align*}
$$

where

$$
\vartheta_1 = \{u^{i,t}, G_{En,seg}^{i,s,t}; x, u\}.
$$

Indices $i, s, t$ denote cost segments $s$ of generator $i$ at time $t$. Parameter $N_G$ denotes the number of controllable (conventional) generators. $C_{noload}^{i,t}$ is the no-load costs of generator $i$ and $C_{Start}^{i,t}$ is its start-up costs. $G_{En,seg}^{i,s,t}$ is the generation in cost segment $s$. $MC_{En,seg}^{i,s,t}$ is the $s^{th}$ segment of the marginal costs of producing power. $g_1(a, x, u)$ and $h_1(a, x, u)$ are the power balance, generator up- and down-times, generator ramping limits, generator upper and lower limits. $x$ and $u$ denote continuous
and binary variables respectively and \( a \) is a parameter vector which contains generation limits, demand, line limits, start-up and shut-down times, and ramping limits. The marginal benefit of consumer \( j \) at time \( t \) is based on a demand function with constant price elasticity. The simplified version of the fitting problem for a piece-wise linear representation of the continuous cost functions is used [49, 50]. Subsequently, a the piece-wise linear curve is transformed into a step-wise one.

**Figure 2.9:** Proposed multistage framework: In a first stage, demand and supply \((MC_{En})\) for energy are matched in a unit commitment. In a second stage, a Pareto-efficient share of balancing and ramping efforts is done in the course of a co-optimization problem of traded energy and reserves \((MC_{En}, MC_{Resup/dn}, MC_{noevt})\).

**Co-Optimization of Traded Energy and Reserves**

Co-optimization of traded energy and reserves has been shown to be an efficient form of energy and reserve power scheduling [51] and [52]. The objective function includes the start-up and no-load costs of the power plants, the market clearing price for energy, event-driven up and down reserves, the lost opportunity costs (LOC) of the generators, the procurement costs of the event and non-event driven reserves, the costs of deployed reserve energy and the costs of abating fluctuations:

\[
\max_{\vartheta_2} \sum_{t=1}^{NT} \left\{ \sum_{i=1}^{NG} \left[ u^{i,t} C_{noload}^{i} + C_{Start}^{i} \right] + MC_{En,seg}^{i,s,t} G_{En,seg}^{i,s,t} \right\}
\]

Commitment costs and costs of energy production
Chapter 2. Centrally Operated System

\[
\begin{align*}
&\sum_{i=1}^{N_G} (LOC_{RV,i,t}^{evt} + LOC_{RV,i,t}^{noevt}) \\
&\text{Lost opportunity costs of reserve provision} \\
&\sum_{p=1}^{N_P} (MB_{RV,seg}^{evt,p,t} D_{RV,seg}^{evt,p,t} + MB_{RV,seg}^{evt,p,t} D_{RV,seg}^{evt,p,t}) \\
&\text{Aggregated benefit of event-based reserves} \\
&\sum_{i=1}^{N_G} \sum_{s=1}^{N_S} (MC_{RV,seg}^{evt,i,s,t} G_{RV,seg}^{evt,i,s,t} + MC_{RV,seg}^{evt,i,s,t} G_{RV,seg}^{evt,i,s,t}) \\
&\text{Costs of event-based reserve capacity} \\
&\sum_{i=1}^{N_G} \sum_{s=1}^{N_S} (MC_{RV,seg}^{noevt,i,s,t} G_{RV,seg}^{noevt,i,s,t} + MC_{RV,seg}^{noevt,i,s,t} G_{RV,seg}^{noevt,i,s,t}) \\
&\text{Costs of non event-based reserve capacity} \\
&\sum_{i=1}^{N_G} \sum_{s=1}^{N_S} (MC_{RV,seg}^{evt,i,s,t} G_{RV,seg}^{evt,i,s,t} + MC_{RV,seg}^{evt,i,s,t} G_{RV,seg}^{evt,i,s,t}) \\
&\text{Costs of event-based reserves energy} \\
&\sum_{i=1}^{N_G} \sum_{s=1}^{N_S} (MC_{RV,seg}^{noevt,i,s,t} G_{RV,seg}^{noevt,i,s,t} + MC_{RV,seg}^{noevt,i,s,t} G_{RV,seg}^{noevt,i,s,t}) \\
&\text{Costs of non event-based reserve energy} \\
&\sum_{q=1}^{N_Q} (MC_{RV,seg}^{noevt,q,t} P_{RV,seg}^{noevt,q,t} + MC_{RV,seg}^{noevt,q,t} P_{RV,seg}^{noevt,q,t}) \\
&\text{Aggregated costs of abating non event-based reserve capacity} \\
&\sum_{qr=1}^{N_Qr} (MC_{RV,seg}^{qr,t} P_{RV,seg}^{qr,t} + MC_{RV,seg}^{qr,t} P_{RV,seg}^{qr,t}) \\
&\text{Aggregated costs of abating ramping requirements} \\
&\sum_{i=1}^{N_G} C_{Ramp}^i \\
&\text{Costs of ramping for generators}
\end{align*}
\]
subject to

\[ h_2(a, x, u) = 0, \quad (2.19) \]
\[ g_2(a, x, u) \leq 0, \quad (2.20) \]

where

\[ \psi_2 = \{ u^{i,t}, G_{\text{En,seg}}, LOC_{\text{Resup},i,t}, LOC_{\text{noevt},i,t}, G_{\text{Resup,cap,seg}}, G_{\text{Resup/dn,en,seg}}, G_{\text{Resup/dn,cap,seg}}, P_{\text{Resup/Resdn,ab,seg}}, P_{\text{Rup/Rdn,ab,seg}}, x, u \}. \]

Indices \( i, s, t \) denote segment \( s \) of generator \( i \) at time \( t \). Index \( p \) refers to segment \( p \) of the marginal benefit curve for event based reserves. Indices \( q \) and \( qr \) denote the segment of the marginal costs of abatement curves for imbalances and ramping. \( MB_{\text{En,seg}}^{i,t} \) is the marginal benefit function for energy. \( MC_{\text{En,seg}}^{i,s,t}, MC_{\text{Resup/dn,ab,seg}}^{(no)evt,i,s,t} \) are the marginal costs of providing energy and (non) event-based up/down-reserves respectively. \( LOC_{\text{Resup}}^{\text{evt/evt},i,t} \) are the lost opportunity costs of generators in case of provision of event/non event-based reserve capacity. \( MB_{\text{Resup/dn,cap,seg}}^{\text{evt,p,t}} \) is the aggregated marginal benefit of event-based reserves. \( MC_{\text{Resup/dn,ab,seg}}^{\text{noevt,q,t}} \) is the piecewise sum of the marginal costs of abatement bids of all demand units and fluctuating injections for non-event up/down imbalances [50]. \( MC_{\text{Rup/dn,ab,seg}}^{qr,t} \) is the \( qr^{th} \) segment of the piecewise sum of the marginal costs of abatement bids for up/down ramping. \( G_{\text{En,seg}}^{i,t}, G_{\text{Resup/dn,cap,seg}}^{i,s,t} \) and \( G_{\text{Resup/dn,en,seg}}^{i,s,t} \) are the energy production, the scheduled amount of up/down reserve capacity, and the scheduled amount of up/down reservoir energy production of generators. \( P_{\text{Resup/dn,ab,seg}}^{\text{noevt,q,t}} \) is the \( q^{th} \)-segment of the avoided amount of fluctuating consumption or injection by non-conventional producers or loads. \( P_{\text{Rup/Rdn,ab,seg}}^{\text{qr,t}} \) is the \( qr^{th} \)-segment of the aggregated shifting efforts of consumers and fluctuating injections to avoid excessive ramping. \( x \) and \( u \) denote the continuous and binary variables, and \( a \) is a parameter vector. The constraints \( h_2(a, x, u) \) and \( g_2(a, x, u) \) comprise the constraints on power balance, start-up and shut down times, capacity limits of generators, demand and lines [47, 53, 24] and appendix B.1.4. The ramping costs are included using eqs. (2.7)-(2.14).

Equations (2.7)-(2.14) include (non-convex) quadratic terms. Therefore the problem is a mixed integer non linear programming problem (MINLP), which is generally hard to solve. In order to keep the problem computationally tractable we apply a relaxation of the quadratic terms as shown in the appendix B.1.5.
Chapter 2. Centrally Operated System

2.4 Simulation Setup

The proposed method is tested using the IEEE-9 bus system as shown in Fig. 2.10 [54]. Technical and economic generation and load data are given in the appendix A.1. The minimum amount of event-based reserves is assumed to be a fixed share of 20% of the highest output of the generator in operation. The amount of non event-based reserves is assumed to be five times the requirements according to an ENTSO-E formula [31]. The approach was implemented in Matlab using the interface YALMIP and IBM ILOG CPLEX as solver [55],[56].

Different market designs were investigated in order to determine the incidence of an efficient sharing of costs of ramping and reserve provision:

- **Benchmark Approach BM, BM_R**: No mechanism to reduce balancing or ramping requirements is implemented. The system operator has the sole balancing responsibility. In case of consideration of ramping costs a separate benchmark approach, BM_R, is used.

- **Market Design R_1**: Only the costs of reserves are shared among market participants. The ramping capabilities are set by the unit commitment in the first stage.

- **Market Design R_2**: Only the costs of ramping are considered in the cost sharing mechanisms. Reserves are provided only by the system operator.

- **Market Design RR**: Both ramping and reserves are considered in the cost sharing mechanism.

All market designs are simulated with and without the presented preference revelation mechanism, which results in eight different cases.

2.5 Results

Fig.2.11 shows the schedule for traded energy with, $G_{En,R}^{1,t}$, $G_{En,R}^{2,t}$, $G_{En,R}^{3,t}$, and without ramping costs, $G_{En,nR}^{1,t}$, $G_{En,nR}^{2,t}$, $G_{En,nR}^{3,t}$. As seen for generator $G_2$ and $G_3$ between times steps 5h-9h and 20h-24h, the consideration of ramping costs reduces the magnitude of ramping events in order to save costs.
2.5. Results

Fig. 2.12a shows the scheduling of generation units to provide event-based reserve capacity for the benchmark approach, and in case of inelastic demand and elastic demand for event-based reserves. Generator 1 and 2 are primarily involved with the reservation of event-based reserve capacity. Fig. 2.12b shows the scheduling of generation units to provide non event-based reserves in the benchmark approach without decentralized efforts to reduce the amount of non event-based reserves. The requirements follow the demand which is due to the applied formula for reserve requirements.

Fig. 2.13a shows the considered change in the bidding structure for event-based reserve capacity. The parametrization of the demand curve for event-based reserves is chosen for numerical reasons. The denominator of the individual curves in eq. (2.1) is multiplied with a factor to change the individual valuation of event-based reserve capacity. As shown in Fig. 2.13b, the amount of procured reserves increases with higher elasticity of the reserve demand curve in absolute terms. However, the relative growth is decreasing.

As seen from eqs. (2.5) and (2.15), also the costs of abating fluctuating injection/demand or ramping events vary with time and are dependent upon several parameters. Due to the parametrization, the costs vary in the different scenarios between the lower bound shown in Fig. 2.14a, and the upper bound as shown in Fig. 2.14b. The same costs of abatement are assumed for ramping events and fluctuations.

The elasticity of the marginal abatement costs for reserves of demand and fluctuating injection $\eta^{\text{noevt},j,t}_{\text{Resup/dn,cap}}$ are linearly modified by adding the term

$$\eta^{\text{noevt},j,t}_{\text{Resup/dn,cap}} + (a + n \cdot b), \quad (2.21)$$

where $a = -0.16$ and $b = 0.04$ were chosen out of numerical reasons. $\eta^{\text{noevt},j,t}_{\text{Resup/dn,cap}}$ is defined in the appendix A.1. $n$ is a tuning variable. The higher $n$, the more elastic is the marginal abatement cost curve.
Figure 2.10: Considered 9 bus system: All loads are assumed to have a pre-defined demand for event-based reserves and a pre-defined marginal cost function to avoid the need for non event-based reserves and ramping.

Figure 2.11: Temporal schedule of generation units \((G_{1,\text{En},t}, G_{2,\text{En},t}, G_{3,\text{En},t})\) in the assumed test system. \(G_{1,\text{En},nR}, G_{2,\text{En},nR}, \text{ and } G_{3,\text{En},nR}\) show the scheduling without consideration of ramping costs. \(G_{1,\text{En},R}, G_{2,\text{En},R}, \text{ and } G_{3,\text{En},R}\) show the scheduling with consideration of ramping costs. Costly large ramping events are reduced in the latter case.
2.5. Results

Figure 2.12: Scheduling of generators $G_{Resup}^{\text{noevt},1,t}$, $G_{Resup}^{\text{noevt},2,t}$, and $G_{Resup}^{\text{noevt},3,t}$ for (a) Event-based reserve capacity: $G_{Resup,b}^{\text{evt},1,t}$, $G_{Resup,b}^{\text{evt},2,t}$, and $G_{Resup,b}^{\text{evt},3,t}$ show the generator scheduling for the benchmark case where the event-based reserve requirements are determined as a fixed share of generation. $G_{Resup,s}^{\text{evt},1,t}$, $G_{Resup,s}^{\text{evt},2,t}$ and $G_{Resup,s}^{\text{evt},3,t}$ show the generator scheduling for case when event-based reserve capacity is valued at most from the demand side. Due to the setup of eq. (2.1), the demand for reserves is lowest during high demand times.

(b) Non event-based reserve capacity scheduling of generators $G_{Resup}^{\text{noevt},1,t}$, $G_{Resup}^{\text{noevt},2,t}$, and $G_{Resup}^{\text{noevt},3,t}$.
Chapter 2. Centrally Operated System

\[ P_{\text{evt}, j, t}^{\text{Resup/dn}} = \max_t \left( \sum_{i=1}^{N_G} G_i, t E_n \right) \]

Segments of event-based reserve demand

Figure 2.13: (a) Aggregated marginal benefit curves for event-based reserve capacity. A higher \( z \) leads to a higher valuation for event-based reserves. The range of the segments depends on the generation schedule and the demand at time \( t \), where \( \max_t(\cdot) \) defines the maximal generation output over the total time horizon.

(b) Scheduled amount of reserve capacity in the market-based approach (Market) in relation to the base case with fixed event-based reserve requirements (Benchmark). A higher valuation leads to an increase in the procured amount of event-based reserves. However, because of a market-based solution, there exists a saturation point at around 5.5 times the amount of procured reserves in the base case.
2.5. Results

2.5.1 Shared Balancing and/or Ramping Effort

Fig. 2.15a shows the ratio of non event-based reserve capacity which has to be available on the demand side in case of shared balancing responsibility in case of market design $R_1$ compared with the benchmark approach. The share is dependent upon the amount of event-based reserves scheduled and the elasticity of the demand side. It is shown that with an increasing demand for event-based reserve requirements, the costs of procurement for non event-based reserve rise and therefore it is more cost efficient to leave balancing responsibility to the demand side. A lower demand side elasticity, and hence higher costs of demand side participation, reduces the share of non event-based reserve capacity by the demand side.

Fig. 2.15b shows the costs of ramping in case of shared ramping efforts compared with costs of ramping in the benchmark approach. It is shown, that higher event-based reserve requirements lead to a relative increase of the ramping costs also in case of energy shifting efforts on the demand side. Improvements in the elasticity of the demand side do not lead to significant improvements in terms of reduced ramping costs. This could mean that the flexibility of the demand is already at a very high level. However, this is also dependent upon the assumed costs of ramping of conventional power plants.

Fig. 2.16a and 2.16b show the amount of abated reserve capacity and ramping costs for the case of shared balancing and ramping responsibility in market design $RR$. The first digit of control variable $n$ refers to the elasticity of abatement costs for reserve capacity. The second digit refers to the control variable for ramping efforts. It is shown in Fig. 2.16a that despite of low ramping flexibility and relatively high costs of abating reserves, $n = (1, 1)$, the amount of decentrally hold reserves increases. Further, it is shown that the cases, $n = (8, 1)$, $n = (1, 8)$, and $n = (8, 8)$, give the same results. This means that either trough demand shifting flexibility, or lower costs of decentralized reserve capacity requirements the same results can be achieved considering a reduction of centrally procured reserves. Results may change with a change in the parameter values.

In Fig. 2.16b it is found that through an additional reduction of centrally procured reserve requirements the costs of ramping are further reduced compared with Fig. 2.15b. Further, the costs of ramping do not rise with an additional demand for event-based reserves as in design $RR$. 
Figure 2.14: Stated marginal costs of abating balancing and ramping effort
(a) Low cost case,
(b) High cost case.
2.5. Results

Event-based reserve elasticity

(a)

(b)

Figure 2.15: Dependent upon tuning variable $n$ from eq. (2.21) and $z$ which influences the demand for event-based reserves, (a) shows the share of the total non event-based reserves taken over by the demand side in design $R_1$, $P_{ab}^{n_{\text{noevt},R_1}}$, compared with the total reserve requirements from the benchmark approach $BM$, $P_{\text{Req}}^{n_{\text{noevt},BM}}$. If 100% of the reserve capacity requirements are decentralized provided, the system costs for non event-based reserves are zero. (b) shows the amount of total ramping costs in design $R_2$, $C_{R_{\text{Ramp}}}^{R_2}$, compared with the costs from the benchmark approach $BM_R$, $C_{R_{\text{Ramp}}}^{BM}$. The higher $z$, the more elastic is the event-based reserve demand. An increase in the scheduled amount of event-based reserves slightly alleviates the cost reduction in design $R_2$. The higher $n$, the more elastic are the non event-based reserve/ramping abatement cost curves respectively.
Figure 2.16: Dependent upon tuning variable \( n \), which modifies the abatement cost elasticities for balancing and ramping, and \( z \), which influences the demand for event-based reserves,

(a) shows the share of the total non event-based reserves taken over by the demand side in design \( RR \), \( P_{ab}^{noevt,RR} \), compared with the total reserve requirements from the benchmark approach \( BM_R \), \( R_{Req}^{noevt,BM_R} \). If 100% of the reserve capacity requirements are decentralized provided, the system costs for non event-based reserves are zero.

(b) shows the amount of total ramping costs in design \( RR \), \( C_{Ramp}^{RR} \), compared with the costs from the benchmark approach \( BM_R \), \( C_{Ramp}^{BM_R} \). The higher \( z \), the more elastic is the event-based reserve demand. The higher \( n \), the more elastic are the non-event based reserve/ramping abatement cost curves respectively.
2.5. Results

2.5.2 Cost Impact of Preference Revelation

The financial impact of a preference revelation mechanism is investigated. Table 2.1 shows the incentive payments per market participant $L_1$, $L_2$, and $L_3$ following Clarke-Groves in comparison to the payments in a Lindahl equilibrium for the considered market designs $R_1$, $R_2$, and $RR$. Since all loads have the same preferences with regards to event-based reserve capacity, the deviations of the payments are small. Further, it can be seen that an additional revenue sufficiency payment is necessary in order to cover the costs of reserve capacity. However, this revenue sufficiency payments depend highly on the choice of the demand curve for event-based reserves and excess payments from the demand side are possible.

Table 2.1: Incentive payments following Clarke-Groves for event-based reserves in relation to payments from the Lindahl equilibrium.

<table>
<thead>
<tr>
<th></th>
<th>$L_1$</th>
<th>$L_2$</th>
<th>$L_3$</th>
</tr>
</thead>
<tbody>
<tr>
<td>$R_1$</td>
<td>0.1</td>
<td>0.113</td>
<td>0.093</td>
</tr>
<tr>
<td>$R_2$</td>
<td>0.095</td>
<td>0.103</td>
<td>0.085</td>
</tr>
<tr>
<td>$RR$</td>
<td>0.100</td>
<td>0.119</td>
<td>0.093</td>
</tr>
</tbody>
</table>

Table 2.2 shows the incentive payments following Clarke-Groves in the setup for non event-based reserves. Different to event-based reserves the share is significantly higher, which is due to the change in the determination of these payments and the change in the shape of the cost curves.

Table 2.2: Incentive payments following Clarke-Groves for non event-based reserves in relation to payments from a Lindahl solution. The first digit in the elements of row $RR$ is the payment for non event-based reserves, the second digit for ramping efforts.

<table>
<thead>
<tr>
<th></th>
<th>$L_1$</th>
<th>$L_2$</th>
<th>$L_3$</th>
</tr>
</thead>
<tbody>
<tr>
<td>$R_1$</td>
<td>1.01</td>
<td>1.01</td>
<td>1.01</td>
</tr>
<tr>
<td>$R_2$</td>
<td>0.223</td>
<td>0.223</td>
<td>0.223</td>
</tr>
<tr>
<td>$RR$</td>
<td>0.192/0.209</td>
<td>0.241/0.209</td>
<td>0.151/0.209</td>
</tr>
</tbody>
</table>

Revenue sufficiency payments are again highly dependent upon the choice of the cost curves for abating reserves. The first number in the row $RR$ shows the relation for non event-based reserves and the second number for ramping costs for the respective loads.
2.6 Summary

This chapter presented a mechanism to efficiently allocate costs of system services, which can provide incentives for decentralized efforts to reduce balancing and ramping services. Market participants, which cause fluctuations in the power balance and excessive ramping requirements, are individually charged according to their willingness to avoid these market disturbances. Due to the public good characteristic of reserves and ramping efforts, a preference revelation mechanism has been applied to ensure truthful statement of the marginal abatement cost curves. Simulation results show that the cost reduction is greater for reduction of ramping requirements than for reserves. However, a comprehensive comparison to assess the advantageousness of either avoiding balancing or ramping efforts requires a relatively large amount of data of the system. Further, excess charges paid by the market participants are possible when a preference revelation mechanism is applied. The method opens new research directions for the market-based incorporation of renewable energy injections and demand side participation. Examples of these applications are shown in the following chapters.
Chapter 3

Performance Based Renewable Energy Support

Public services are never better performed than when their reward comes in consequence of their being performed, and is proportioned to the diligence employed in performing them. A. Smith, The Wealth Of Nations, Book V, Chapter 1, Part II, p. 719, para. b20.

The previous chapter presented the theoretic foundations of a mechanism to share costs of keeping system balance. In this chapter, the proposed methodology is applied to the issue of financial support for fluctuating renewable sources. In specific, how financial incentives can be set, to achieve an overall minimization of support and system costs if renewable energy generation is introduced in large scale. This chapter is based on ref. [57].

3.1 Introduction and Motivation

Financial support for renewable energy injection in the past decade resulted in a significant increase of the total installed capacity. Existing
support schemes can be split into two parts [58]: Capacity-driven and price-driven. Capacity driven policies, i.e. tradable green certificates, describe policies which focus on the quantity regulation (for example the quantity of consumed electricity produced by RES). Price-driven policies, i.e. feed-in tariffs, regulate the market price of the RES production, which is currently the prevailing instrument applied by European countries. Tables 3.1 shows the applied support schemes in different European states. Experience to date confirms that a feed-in tariff (FIT) policy has been the most successful approach for a rapid expansion renewable generation capacity, as demonstrated in countries with high renewable feed-in penetration [59].

However, promoted RES-injection with rigid feed-in support, which only takes into account the quantity of electricity produced without any balancing responsibility, creates several challenges for different entities:

1. From a system operator’s perspective it creates high costs of system operation: In order to deal with the occasionally rapid and hard to predict changes in the power production of renewable energy sources, the system operators must provide additional reserve capacity [7], and ensure that the other generating units have enough inter- and intra-hour ramping capabilities [60, 61, 62]. Procuring these flexible generation resources can be expensive because transmission constraints may hinder access to large pumped-hydro storage facilities, or other less expensive flexible plants.

2. From a market participant’s perspective it creates wrong invest-
### 3.1. Introduction and Motivation

Table 3.1: Support Policy to enhance renewable energy integration in power systems by country, Source: [59], pp. 16-17

<table>
<thead>
<tr>
<th>Member state</th>
<th>Hydro</th>
<th>Wind</th>
<th>Biomass &amp; Waste</th>
<th>Biogas</th>
<th>Photovoltaic</th>
<th>Geothermal</th>
</tr>
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<td>Green Certificates with guaranteed minimum price</td>
<td>Green Certificates with guaranteed minimum price</td>
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</table>
ment incentives: Schemes designed to support production from RES distort the market and decrease incentives for investments in flexible generation by other market participants [63]. Rigid feed-in tariffs do not require RES owners to keep their production in line with their forecast and give them no incentive to firm up their output using investment in flexible resources or through bilateral contractual agreements with owners of such resources.

3. From a policy maker's perspective it conflicts with other policy instruments to reduce CO\(_2\)-emissions: These schemes may also conflict with other policy instruments to reduce CO\(_2\)-emissions, such as an emission certificate market [64, 65]. A fast growth in the share of renewable energy sources suppresses prices for emission allowances and weakens the effectiveness of this instrument. Moreover, Fig. 3.1 shows that the costs of renewable energy support are primarily socialized via surcharges. The resulting welfare incident is dependent upon the income level of households, and may create concerns with regards to the general public acceptance of reducing CO\(_2\)-emissions [64, 65].

One possibility to reduce the negative impact of price-driven support schemes is to introduce a penalty system, which is proportional to the costs that fluctuating energy injection incurs. In this chapter (a) an adaptive support scheme is proposed, which rewards renewable generation units based on their performance to reduce additional system costs incurred through high reserve capacity requirements, and (b) the role of flexible demand (DR) which states its marginal costs of abating fluctuations supplementary to an adaptive support scheme is assessed. The proposed adaptive support scheme is a compromise between a full market integration of renewable energy sources and a respective financial risk exposure, and a feed-in tariff scheme without balancing responsibility. The cost allocation mechanism for non event-based reserves, as presented in chapter 2, is applied. It is assumed that fluctuating injection affects the costs associated with the provision of non event-based reserve capacity.

3.2 Literature Review

To the best of knowledge no similar approaches have been presented which modify existing feed-in support policies to a more market-based
3.2. Literature Review

Figure 3.2: Schematic illustration of a performance based component, $T_P$, in the support of renewable fluctuating energy sources in monetary units (m.u.). In case the allocated system costs of balancing, $C(I^w)$, decrease due to decentralized investments $I^w$ made by wind farm $w$ the adaptive component, $\overline{T}_P$, increases. A lower bound, $T_P$, may provide some sort of financial hedge and is independent from investments done in higher operability. Both components add to a total revenue $T_P$.

framework. Ref. [62] and [66] estimate the system costs of adding wind generation and the costs of wind prediction errors respectively. The results show that the benefits are highly sensitive to how much of the inherent variability of wind generation is mitigated. Ref. [67] gives a detailed review about RES support in Spain and recommendations with regard to possible locational and operational economic signals. Ref. [68] summarizes current policy instruments for the European Union and how they converge. Ref. [69] highlights major principle design options with regard to renewable feed-in policy such as the static efficiency or cost effectiveness, dynamic efficiency, the compatibility with other market principles, and distributional effects. Moreover, the authors of ref. [69] conclude that a successful policy includes:

- A detailed knowledge of generation costs when designing support schemes: With regard to the presented approach this is ensured through an augmented co-optimization problem.

- Cost control for price-driven support schemes: This would primarily effect the fixed part of the proposed support scheme.

- Clear and fair burden-sharing rules: The cost allocation mechanism for non event-based reserves, as presented in chapter 2, is applied in this framework. Hence, a cost-share is established, which is based on the individual preferences to avoid negative externalities in the system.
Ref. [70] presents the most convincing arguments in favor of support for renewable energy besides a pure market-based integration.

### 3.3 Structure of a Performance Based RES Support

The aim of a performance-based RES support scheme is to encourage RES owners to mitigate the costs of imbalances that they create. The financial incentives that they provide should therefore be a function of the balancing performance of the various plants. These incentives might involve two components and Fig. 3.2 shows how these components might vary as a function of a measure of performance of each plant (in monetary units, m.u.): First, a fixed component, $T_P$, which reduces investment risks due to uncertain wind availability. The determination of $T_P$ requires the consideration of i.e. investment risks for the investor, the societal desires on renewable energy feed-in and hence CO$_2$ emissions.

Second, an adaptive support component, $\overline{T_P}$, which considers the system costs that fluctuating in-feed causes. The performance stated in Fig. 3.2 is based on the system costs that presumably occur due to higher balancing requirements in case of the renewable energy in-feed. The lower the share of the system costs allocated to the market participants, the higher his performance. Therefore efforts to avoid deviations are decentralized. Thus, the total revenue for the wind-farm operator, $T_P$, can be written as:

$$T_P + \overline{T_P} = T_P. \quad (3.1)$$

If the operator of a renewable energy source $w$ wants to avoid random deviations from the schedule, supplemental investments in onsite storage, auxiliary generation, or the establishment of third party agreements to improve the operational performance have to be made. These investments are denoted with $I^w$. This chapter focuses on the determination of $\overline{T_P}$ from the perspective of power system operation, in order to achieve a certain desired scheduling performance from renewable energy in-feed. The adaptive component, $\overline{T_P}$, is determined by allocating the costs of system operation efficiently to the market participants and subtract them from a predetermined fixed value such as a feed-in tariff, or a grid tariff.
3.3. Structure of a Performance Based RES Support

The determination of $T_P$ requires the consideration of investment risks for the investor, and the societal desires on renewable energy feed-in, and hence CO$_2$-emissions. One possibility to evaluate renewable energy support policy is from the point of political economy, since legislation of renewable energy support comes from governments, which aim to be reelected. Ref. [71] is used in order to formally motivate the consideration of this macroeconomic perspective. Assume that the environmental quality, $EQ$, is a function of the regulatory efforts to keep the environment clean, $RE$, and the national income of a country, $Y$,

$$EQ = eq(RE,Y),$$

where the national income is the income earned by the residents of a country, whether in the home country or abroad. Regulatory efforts include an feed-in subsidy, where the costs are allocated to the residents of the country. The median voter has a share $a$ of the national income $Y$, $Y^m$,

$$Y^m = a \cdot Y.$$

Hence, the national income is a function of the regulatory effort to remain the environmental quality:

$$Y = y(RE),$$

where

$$y(RE)' \leq 0, \quad \text{and}$$

$$y(RE)'' \geq 0.$$

Eqs. (3.4)-(3.6) comprise that the higher the regulatory stringency, the less income the residents get. The median voter’s utility can be defined as,

$$U^m = (a \cdot y(RE), eq(RE, y(RE))).$$

The ideal stringency of environmental policy $RE^*$ can now be derived by differentiation:

$$U_Y^m aY_{RE} + U_{EQ}^m \cdot (EQ_{RE} + EQ_Y Y_{RE}) = 0,$$

where $U_Y^m$ is the derivative of utility $U^m$ with regard to $Y$, $Y_{RE}$ is the derivative of $Y$ with regards to $RE$, $U_{EQ}^m$ is the derivative of the utility with regard to environmental quality $EQ$, $EQ_{RE}$ is the derivative of the
environmental quality with regard to regulatory stringency, and $EQ_Y$ is the derivative of the environmental quality with regard to national income. The first term can be interpreted as the marginal costs of an environmental policy and the second term as the marginal benefit of the environmental policy.

With regard to the presented approach it is possible to determine the term $EQ_{RE}$, which is environmental quality, or the amount of emitted CO$_2$-emissions, due to a higher share of supported renewable injection. However, a detailed macroeconomic analysis of a fixed feed-in support component with regard to the parametrization of a model, including game theoretic considerations due to the necessary multinational efforts of emission avoidance, is out of the scope of this thesis. This chapter focuses on the determination of $TP$ from the perspective of power system operation, in order to achieve a certain desired scheduling performance from renewable energy feed-in.

3.4 Adaptive In-feed Support Component

The costs of system operation in presence of fluctuating injection comprise additional costs through non event-based reserve capacity reservation. A co-optimization of reserves and traded energy is performed, similar to chapter 2, in order to determine the optimal amount of traded energy, event-based and non event-based reserve capacity. Additionally the optimization considers costs of emissions, i.e. due to the existence of some form of emission certificate trading system. The costs of ramping are neglected in this chapter, but the approach can be extended in this direction as shown in chapter 2.

3.4.1 Costs of Abating Fluctuating In-feed/Demand

The marginal costs of abating deviations may comprise maintenance costs of storage operation, auxiliary generation, or transactions costs in bilateral trade. For simplicity, only the cost curves for up-reserves are shown. Similar considerations can be done for down-reserves.

Fluctuating In-feed

Generators with fluctuating injection state their costs of avoiding random deviations from the announced schedule to the system operator.
The marginal costs of renewable feed-in of site \( w \) for avoiding imbalances from the schedule at time \( t \), \( Q_{\text{Resup,ab}}^{\text{noevt},w,t} \), are of the form:

\[
MC_{\text{Resup,ab}}^{\text{noevt},w,t} = \left( \frac{Q_{\text{Resup,ab}}^{\text{noevt},w,t}}{F_{\text{Resup,ab}}^{\text{noevt},w,t}} \right)^{\epsilon_{\text{Resup,ab}}^{\text{noevt},w,t}},
\]

(3.9)

where \( \epsilon_{\text{Resup,ab}}^{\text{noevt},w,t} = \frac{1}{\eta_{\text{Resup,ab}}^{\text{noevt},w,t}} \). \( F_{\text{Resup,ab}}^{\text{noevt},w,t} \) is a positive factor and \( \eta_{\text{Resup,ab}}^{\text{noevt},w,t} \) is the elasticity of supply for abating deviations and \( Q_{\text{Resup,ab}}^{\text{noevt},w,t} \) is the abated amount of fluctuations at time instant \( t \). Fig. 3.3 shows the influence of the design parameters on the shape of the cost curve. The shown cost function gives a constant price elasticity for abated reserves. This means that the percentage change of the marginal costs of abatement in response to the abated amount of fluctuations stays constant. However, other forms, such as a quadratic cost function, or linear cost function, are conceivable but they give changing price elasticities dependent upon the point of operation. An evaluation which cost function fits best depending upon the technology for balancing assumed is out
of the scope of this chapter.

It is assumed that the elasticity $\eta_{\text{Resup,ab}}^{w,t}$ and the scaling factor $F_{\text{Resup,ab}}^{w,t}$ are dependent upon the investment in onsite flexibility, $I_w$, and the average wind feed-in per day $G_w^f$. The elasticity $\eta_{\text{Resup,ab}}^{w,t}$ is a function of the average wind injection forecast as follows:

$$\eta_{\text{Resup,ab}}^{\text{noevt},w,t} = \min\left(\eta_{\text{Resup,ab}}^{\text{noevt},w,t}, a_{\text{Resup,ab}}^{\text{noevt},w,t} + b_{\text{Resup,ab}}^{\text{noevt},w,t} G_w^f\right),$$

(3.10)

and the scaling factor is determined via,

$$F_{\text{Resup,ab}}^{\text{noevt},w,t} = (a_{\text{Resup,ab}}^{\text{noevt},w,t} + a_{\text{Resup,ab}}^{\text{noevt},w,t} + b_{\text{Resup,ab}}^{\text{noevt},w,t} G_w^f) F_{\text{Resup,ab}}^{\text{noevt},w,t},$$

(3.11)

where $a_{\text{Resup,ab}}^{\text{noevt},w,t}$ and $b_{\text{Resup,ab}}^{\text{noevt},w,t}$ are fixed factors. $a_{\text{Resup,ab}}^{\text{noevt},w,t}$ is introduced for numeric reasons. Eqs. (3.10)-(3.11) state that wind-farms already have a certain inherent flexibility. This is because high wind availability allows for easier control of wind farm production. In this paper, the linear dependence in eq. (3.11) does not change over time $t$.

With regards to the dependency upon the amount of investment in onsite flexibility, $I_w$, factor $a_{\text{Resup,ab}}^{\text{noevt},w,t}$ is equal to,

$$\cdots = a_{\text{Resup,ab}}^{\text{noevt},w,t} + \beta_{\text{Resup,ab}}^{\text{noevt},w,t} I_w - \gamma_{\text{Resup,ab}}^{\text{noevt},w,t} I_w^2, \text{ for } I_w \leq \frac{\beta_{\text{Resup,ab}}^{\text{noevt},w,t}}{2 \gamma_{\text{Resup,ab}}^{\text{noevt},w,t}},$$

(3.12)

$$\cdots = a_{\text{Resup,ab}}^{\text{noevt},w,t} + \frac{\beta_{\text{Resup,ab}}^{\text{noevt},w,t} I_w^2}{4 \gamma_{\text{Resup,ab}}^{\text{noevt},w,t}}, \text{ for } I_w > \frac{\beta_{\text{Resup,ab}}^{\text{noevt},w,t}}{2 \gamma_{\text{Resup,ab}}^{\text{noevt},w,t}},$$

(3.13)

where $a_{\text{Resup,ab}}^{\text{noevt},w,t}$, $\beta_{\text{Resup,ab}}^{\text{noevt},w,t}$, and $\gamma_{\text{Resup,ab}}^{\text{noevt},w,t}$ are cost factors which determine the impact of a change in the investments on the flexibility of the wind site. Eqs. (3.12)-(3.13) include that the flexibility cannot be increased over a certain threshold. The dependency upon the amount of investments has decreasing returns to scale, which means that a large investment into a certain technology does not linearly map into an increase of the balancing performance. All parameters are dependent upon the applied technologies on the wind farm site with regards to balancing technology, and the market environment the wind-farm is faced with, i.e. the amount of contractible flexible resources in the system.
3.4. Adaptive In-feed Support Component

Demand

The marginal costs of load \( j \) for avoiding imbalances from the schedule at time \( t \), \( Q_{\text{Resup,ab}}^{j,t} \), are of the form:

\[
MC_{\text{Resup,ab}}^{\text{noevt},j,t} = (Q_{\text{Resup,ab}}^{\text{noevt},j,t} F_{\text{Resup,ab}}^{\text{noevt},j,t} \epsilon_{\text{Resup,ab}}^{\text{noevt},j,t}),
\]

(3.14)

where \( \epsilon_{\text{Resup,ab}}^{\text{noevt},j,t} = \frac{1}{\eta_{\text{Resup,ab}}^{\text{noevt},j,t}} \) is fixed. \( F_{\text{Resup,ab}}^{\text{noevt},j,t} \) is also a fixed positive factor. For simplicity, it is assumed that the marginal costs of abating fluctuations for demand are not coupled with the marginal costs functions of abating fluctuating feed-in. This interaction is part of future research.

3.4.2 Reserve Requirements

The system operator determines the amount of reserves in case of no decentralized efforts of fluctuating feed-in and demand to reduce deviations from the schedule. With regard to the amount of reserves necessary, chance-constraints are applied to determine probabilistic bounds for the amounts of up and down reserve \( R_{\text{Req,Resup/dn,cap}}^{\text{noevt},t} \) required in order to guarantee the netting of the negative and positive imbalances, \( \tilde{x}^t_{\text{neg/pos}} \), at every time instant \( t \) with a probability \( 1 - \gamma \):

\[
\min_{R_{\text{Req,Resup,cap}}^{\text{noevt},t}, R_{\text{Req,Resdn,cap}}^{\text{noevt},t}} \sum_{t=1}^{N_T} R_{\text{Req,Resup,cap}}^{\text{noevt},t} + R_{\text{Req,Resdn,cap}}^{\text{noevt},t},
\]

(3.15)

subject to

\[
P(\tilde{x}^t_{\text{neg}} \leq R_{\text{Req,Resup,cap}}^{\text{noevt},t}) \geq (1 - \gamma), \quad (3.16)
\]

\[
P(\tilde{x}^t_{\text{pos}} \leq R_{\text{Req,Resdn,cap}}^{\text{noevt},t}) \geq (1 - \gamma). \quad (3.17)
\]

In order to solve this chance constraint optimization problem, the scenario approach using the Markov-Chain-Monte-Carlo scenario generation is applied [72, 73]. The main idea of [72] is to consider only a finite number of instances (scenarios) of the uncertain parameter, and then solve a corresponding linear program. Following [72] and [74] a lower bound for the number of scenarios that should be extracted to provide the desired probabilistic guarantees with high confidence is provided.
Chapter 3. Renewable Energy Support

A formal representation is given in appendix B.2.1. The main advantage of this method is that it does not require knowledge about the distribution function of the uncertain parameters. The formulation is an approximation because the uncertainties associated with each time period are considered to be independent.

3.4.3 Co-Optimization

A co-optimization of energy, event/non event-based reserves including the costs of $CO_2$ emissions is performed. The objective function includes the start-up and no-load costs of the power plants, the market clearing price for energy, event-based up and down reserves, the lost opportunity costs (LOC) of generators, the procurement costs of the event and non-event driven reserves, the costs of abating fluctuations in generation and demand, and the costs of avoiding ramping efforts:

$$\max_\vartheta \sum_{t=1}^{N_T} \left\{ - \sum_{i=1}^{N_G} (u_{i,t}^t C_{noload}^i + c_{Start}^i) + MC_{En,seg}^i \right\} + G_{En,seg}^i$$

Commitment costs and costs of energy production

$$- \sum_{i=1}^{N_G} (LOC_{Resup}^{evt,i,t} + LOC_{Resup}^{noevt,i,t})$$

Lost opportunity costs of reserve provision

Figure 3.4: Scenarios drawn from historical data of all considered uncertainties are bounded by $R_{Req,Resdn,cap}^{noevt,t}$ and $R_{Req,Resup,cap}^{noevt,t}$ with a certain probability $\gamma$. 

A formal representation is given in appendix B.2.1. The main advantage of this method is that it does not require knowledge about the distribution function of the uncertain parameters. The formulation is an approximation because the uncertainties associated with each time period are considered to be independent.
3.4. Adaptive In-feed Support Component

\[
- \sum_{i=1}^{N_G} \sum_{s=1}^{N_S} \left( MC^{\text{evt},i,s,t}_{\text{Resup},\text{cap},\text{seg}} G^{\text{evt},i,s,t}_{\text{Resup},\text{cap},\text{seg}} + MC^{\text{evt},i,s,t}_{\text{Resdn},\text{cap},\text{seg}} G^{\text{evt},i,s,t}_{\text{Resdn},\text{cap},\text{seg}} \right)
\]

Costs of event-based reserve capacity

\[
- \sum_{i=1}^{N_G} \sum_{s=1}^{N_S} \left( MC^{\text{noevt},i,s,t}_{\text{Resup},\text{cap},\text{seg}} G^{\text{noevt},i,s,t}_{\text{Resup},\text{cap},\text{seg}} + MC^{\text{noevt},i,s,t}_{\text{Resdn},\text{cap},\text{seg}} G^{\text{noevt},i,s,t}_{\text{Resdn},\text{cap},\text{seg}} \right)
\]

Costs of non event-based reserve capacity

\[
- \sum_{i=1}^{N_G} \sum_{s=1}^{N_S} \left( MC^{\text{evt},i,s,t}_{\text{Resup},\text{en},\text{seg}} G^{\text{evt},i,s,t}_{\text{Resup},\text{en},\text{seg}} + MC^{\text{evt},i,s,t}_{\text{Resdn},\text{en},\text{seg}} G^{\text{evt},i,s,t}_{\text{Resdn},\text{en},\text{seg}} \right)
\]

Costs of event-based reserve energy

\[
- \sum_{i=1}^{N_G} \sum_{s=1}^{N_S} \left( MC^{\text{noevt},i,s,t}_{\text{Resup},\text{en},\text{seg}} G^{\text{noevt},i,s,t}_{\text{Resup},\text{en},\text{seg}} + MC^{\text{noevt},i,s,t}_{\text{Resdn},\text{en},\text{seg}} G^{\text{noevt},i,s,t}_{\text{Resdn},\text{en},\text{seg}} \right)
\]

Costs of non event-based reserve energy

\[
- \sum_{q=1}^{N_Q} \left( MC^{\text{noevt},q,t}_{\text{Resup},\text{ab},\text{seg}} P^{q,t}_{\text{Resup},\text{ab},\text{seg}} + MC^{\text{noevt},q,t}_{\text{Resdn},\text{ab},\text{seg}} P^{q,t}_{\text{Resdn},\text{ab},\text{seg}} \right)
\]

Aggregated costs of abating non event-based reserve requirements

\[
- \sum_{w=1}^{N_W} MC^{w}_{\text{Spill}} G^{w,t}_{\text{En}} - \sum_{e=1}^{N_E} MC^{e,t}_{\text{Em,seg}} E^{e,t}_{\text{seg}}
\]

Costs of wind spillage Costs of emissions

\[
(3.18)
\]

subject to

\[
h(a, x, u) = 0,
\]

\[
g(a, x, u) \leq 0,
\]

where

\[
\vartheta = \{ u^{i,t}, G^{i,s,t}_{\text{En,seg}}, LOC^{\text{evt},i,t}_{\text{Resup}}, LOC^{\text{noevt},i,t}_{\text{Resup}}, G^{i,s,t}_{\text{Resup,\text{cap},\text{seg}}}, G^{i,s,t}_{\text{Resdn,\text{cap},\text{seg}}}, G^{i,s,t}_{\text{Resup,\text{en},\text{seg}}}, G^{i,s,t}_{\text{Resdn,\text{en},\text{seg}}}, P^{q,t}_{\text{Resup/dn,ab,seg}}, G^{w,t}_{\text{En}}, E^{e,t}_{\text{seg}}, x, u \}.
\]

Indices \(i, s, t\) denote segment \(s\) of generator \(i\) at time \(t\). Indices \(j, k, t\) denote segment \(k\) of load \(j\) at time \(t\). Indices \(q/qr\) denote the segment of the marginal costs of abatement curves for imbalances/ramping. \(MC^{(\text{no})\text{evt},i,s,t}_{\text{Resup/dn,\text{cap,\text{seg}}}}\) and \(MC^{(\text{no})\text{evt},i,s,t}_{\text{Resup/dn,\text{cap,\text{seg}}}}\) are the marginal
Chapter 3. Renewable Energy Support

costs of providing energy and event and non-event driven up/down-reserve capacity and energy respectively. $LOC_{\text{Resup}}^{(\text{no})\text{evt},i,t}$ are the lost opportunity costs of generators in case of provision of non-event driven reserve capacity. $MC_{\text{Resup/}dn,\text{ab,seg}}^{\text{noevt},q,t}$ is the piecewise sum of the marginal costs of abatement bids of all demand units and fluctuating injections for non-event up/down imbalances [50]. $G_{\text{En,seg}}^{i,s,t}, G_{\text{Resup/}dn,\text{cap,seg}}^{\text{noevt},i,s,t}$ and $G_{\text{Resup/}dn,\text{en,seg}}^{\text{noevt},i,s,t}$ are the energy production and the scheduled amount of up/down reserve capacity and energy deployed of the generators. $P_{\text{Resup/}dn,\text{ab,seg}}^{q,t}$ is the avoided amounts of fluctuating consumption or injection by non-conventional producers or loads. $Em_{e,t}^{\text{seg}}$ is the $e^{th}$-segment of the amount of emissions which arise with the production of traded energy, event-based reserve energy, and non event-based reserve energy [75]. A quadratic cost curve to determine the costs of emissions is assumed:

$$MC_{Em}^{t} = a_{Em}^{t} + b_{Em}^{t}Em^{t} + c_{Em}^{t}Em^{t2},$$ (3.21)

where $a_{Em}^{t}, b_{Em}^{t}, c_{Em}^{t} \geq 0$, and $Em^{t}$ is the amount of emissions at time $t$.

Different from the model in chapter 2, the demand for event-based reserves is assumed to be a fixed fraction of the capacity of the largest generator in operation at time $t$. Parameter $MC_{Em,seg}^{t}$ is the segment $e$ of the cost curve of emissions. $x$ and $u$ denote the continuous and binary variables and $a$ is a parameter vector. The constraints $h(a, x, u)$ and $g(a, x, u)$ comprise the constraints on power balance, energy balance, start-up and shut down times, capacity limits of generators, demand and lines [24], [25], [47, 53]. It is assumed that the need of reserve energy is a certain fraction of the determined reserve capacity of the system operator.

3.5 Simulation Setup

A simulation study using an IEEE 24-bus system as shown in Fig. 3.5 is performed [75]. The following costs of abatement parameters for wind farm $W_1$ are assumed: $F_{\text{Resup,ab}}^{\text{noevt},w,t} = 0.5, \alpha_{\text{Resup,ab}}^{\text{noevt},1,t} = \eta_{\text{Resup,ab}}^{\text{noevt},1,t} \beta_{\text{Resup,ab}}^{\text{noevt},1,t} = 0.0003, \gamma_{\text{Resup,ab}}^{\text{noevt},1,t} = 4 \times 10^{-9}, \alpha_{\text{Resup,ab}}^{\text{noevt},1,t} = 3 \times 10^{-4}$. The costs of abatement parameters for wind farm $W_2$ are the same.
3.6. Results

It is assumed that wind farm $W_1$ initially invests $I^1 = 1000$ m.u. into flexibility and linearly increases this amount in the scenarios by another 1000 m.u. Wind farm $W_2$ starts from $I^2 = 500$ m.u. dollar investment and increases in equally distant steps of 500 m.u. The costs of abatement of non event-based reserve requirements on the demand side are varied by multiplying the nominal value $F_{\text{noevt},j,t}^{\text{Resup/dn,ab}}$ with a factor of 0.5 in five equally distant steps up to 1.5. This means that the abatement costs for fluctuations on the demand side get lower. The base case scenario in this simulation study assumes the initial investments sums for the wind-farms and the initial factors in the demand side abatement cost curve.

Load data for energy demand are taken from [76]. Technical and economic generation data, and line data are given in [48] and [77]. Further data for demand and generation are given in the appendix A.2. For the simulation of renewable feed-in uncertainty real data of forecasted and measured in-feed from wind sites in the U.S. for the years 2004-2007 were used [78]. 25 different wind/load scenarios were simulated.

In Fig. 3.6a-3.6c the red line corresponds to the median value of the scheduled load and the wind injection of the wind farms at bus 103 and 120 respectively. The box corresponds to the 25th and 75th percentiles of the injection scenarios. 25 different scenarios were assumed. Outliers (red +) are drawn if they are larger than $q_2 + 1.5(q_2 - q_1)$ or smaller than $q_2 - 1.5(q_2 - q_1)$, where $q_1$ and $q_2$ are the 25th and 75th percentiles. In Fig. 3.7 and 3.8 the costs of abating non event-based reserve capacity are shown for wind farm $W_1$. As in the previous chapter, costs of abating fluctuating feed-in vary between these two cost settings.

3.6 Results

3.6.1 Impact of Balancing Performance

In the following the impact of different costs of abating non event-based reserve requirements with regard to the wind sites and the demand is assessed. Fig. 3.9 shows the relationship between the share on the total costs in case of one wind farm $W_1$ and the demand, dependent upon the investments in flexibility from the wind site and the flexibility of the demand (the elasticity of the cost curves for abating non event-based reserve requirements). The flexibility of demand is stated as
Figure 3.5: Considered IEEE 24-bus system with wind farm $W_1$ at bus 103 and wind farm $W_2$ at bus 120.
Figure 3.6: Distribution of the schedule for load and wind in the different scenarios, (a) Distribution of the total load in the considered scenarios, (b) Distribution of wind injection at wind site $W_1$ in the considered scenarios, (c) Distribution of wind injection at wind site $W_2$ in the considered scenarios.
Figure 3.7: Stated costs of abating decentrally fluctuations from wind site 1, low cost case. $\Delta P^w$ defines the difference between the forecast and a worst case actual feed-in scenario.

Figure 3.8: Stated costs of abating decentrally fluctuations from wind site 1, high cost case. $\Delta P^w$ defines the difference between the forecast and a worst case actual feed-in scenario.
3.6. Results

$DR1 - DR5$ where $DR1 < DR2 < DR3 < DR4 < DR5$. It is shown that in case of a very flexible demand side, the cost share of the wind site rises significantly. However, this can be alleviated through additional investments in the wind site flexibility.

![Diagram showing share on total cost of wind site $W_1$, $Share^{W_1}$, dependent upon investments in flexibility and different increasing levels of demand side flexibility $DR1$-$DR5$, compared with share on total costs of the demand side, $Share^{D}$. Only one wind site is assumed in the system.](image)

Figure 3.9: Share on total cost of wind site $W_1$, $Share^{W_1}$, dependent upon investments in flexibility and different increasing levels of demand side flexibility $DR1$-$DR5$, compared with share on total costs of the demand side, $Share^{D}$. Only one wind site is assumed in the system.

In Fig. 3.10, the payments of the wind-farm relative to the base case are shown dependent upon the investments in the wind farm flexibility. Different case studies show the effect of demand response which may also be promoted. It is shown that the relative gain of investment in flexibility is alleviated in case of low flexibility of the demand side. Fig. 3.11 shows the payments of the demand side dependent upon the investments of the wind farm in flexibility, where a higher demand response leads to lower payments compared with the base case scenario where the initial investments sums for the wind-farms and the initial factors in the demand side abatement cost curve (DR1) are assumed.

Fig. 3.12 shows the ratio of the payments of the wind farm 1, if one wind farm is connected to the system compared with the case of an additional second wind farm $W_2$. The payments in case of one wind farm are significantly higher. This is due to several reasons: First, in case of two wind farms, the netting of imbalance takes place which leads to a lower additional need for non event-based reserve capacity. This is important if the application of the approach has to consider a strong correlation between different sources of fluctuating supply or if the correlation is weak. Second, the price for reserve capacity is
Figure 3.10: Revenue of wind farm $W_1$ dependent upon investments in flexibility and different increasing levels of demand side flexibility DR1-DR5 compared with the base case scenario. Only one wind site is assumed in the system.

Figure 3.11: Payment of the aggregated demand side dependent on its own flexibility DR1-DR5 and level of investment of the wind farm compared with the base case scenario. Only one wind site is assumed in the system.

lower since production from conventional power plants is substituted by wind injection. In case of higher investments in wind site flexibility the difference between the cost shares is reduced. This means that the marginal return of additional investments in case of only one wind farm is higher.

Fig. 3.13 shows the ratio of the payments of the demand side in case of one and two wind sites connected to the system. Payments are generally
higher in case of a low flexibility of demand, DR1. If wind farms are investing in flexibility, payments of the demand side in case of two wind farms attached are relatively higher compared to the case with only one wind farm. If demand is more flexible, DR2-DR5, the relative return of additional flexibility is in this simulation higher in case of only one wind-farm attached. Therefore, in case of a higher wind penetration, the investments for the demand side have to be relatively higher in order to avoid higher payments.

![Graph showing payments of wind farm W1](image1)

**Figure 3.12:** Payments of wind farm W1 in case it is the only wind farm in the system in relation to the payments if there exists a second wind farm.

![Graph showing payment of the demand side](image2)

**Figure 3.13:** Payment of the demand side in case of only one wind farm in the system in relation to two wind farms in the systems.
3.6.2 Impact of Reserve Requirements

The amount of scheduled non event-based reserve capacity is crucial for the financial impact of the cost allocation mechanism. In case of non event-based reserve capacity it is considered that deviations from the day ahead-forecast are compensated via an additional market mechanism, i.e. an intra-day market. Therefore, additional trading activity is approximated by a reduced demand for non event-based reserve capacity. Fig. 3.14 shows the decrease in the revenue in case of higher demand for reserve capacity compared to the base case where 30% of the day ahead reserve capacity determined via eqs. (3.15)-(3.17) is used for the co-optimization. The revenue of the wind-farm is averaged over all demand response scenarios DR1 – DR5. The decreasing revenue can be explained by higher costs in holding reserve capacity. However, investments in flexibility lead to an increase in the revenue, though with decreasing return.

Figure 3.14: Revenue averaged over all cases of demand response compared with base case where 30% of the predetermined day ahead reserve capacity is scheduled. I$^1_1$-I$^1_6$ refer to linearly increasing investments in wind site flexibility from I$^1_1$ = 1000 m.u. to I$^1_6$ = 6000 m.u. .

3.6.3 Impact of Preference Revealing Mechanism

In this simulation the Clarke-Groves mechanism was also applied. It could be observed that the incentive-based payments resulting from the mechanism vastly exceed the payments from the Lindahl clearing. This
is due to the significant difference in value between the iteratively determined system cost curves, and the marginal cost of abatement curves. The system curve exceed the marginal cost of abatement curves to a great extent. This leads to a further conclusion that it has to be considered that on the one hand loads do have an impact on the market outcome for the public good clearing to achieve non zero incentive-based payments, but also limitations regarding the other extreme case of high payments because of a high discrepancy between marginal abatement costs and system costs may appear.

3.7 Summary

In this chapter an adaptive support scheme for renewable energy feed-in, based on the efforts to remain the announced schedule of production has been proposed. The overall costs of system operation can be reduced due to decentralized balancing efforts by the market participants. Further, new market participants’, such as storage owners, find indirectly financial opportunities for offering their services to fluctuating generators. However, it has been shown, that additional external support schemes for flexibility on the demand side may counteract the financial impact of the proposed support scheme. With regard to incentive-based payments it has to be considered that high payments may occur in case of a high discrepancy between system costs of non event-based reserve and the marginal costs of abating them. Additional policies for emission abatement, i.e. emission certificates, interact with a renewable energy support since the costs of fossil-based flexible generation units for balancing the system are influenced.
Chapter 4

Cost Allocation in a Decentralized System

The difficulty lies not so much in developing new ideas as in escaping from old ones. J. M. Keynes, The General Theory of Employment, Interest and Money, Preface

In European power markets, the imbalance settlement market provides the possibility to achieve a market-based match between generation and consumption. The settlement is managed by the system operator. In this chapter a settlement design is presented, which is based on a charge for ancillary service capacity and deployed energy in a system setup, where market operation is separated from the system operator’s duty to remain system security. Thereby, principles of mechanism design, non-linear pricing, and public good theory for truthful revelation of preferences are combined. This chapter is based on ref. [79] and [80].

4.1 Introduction and Motivation

As part of their responsibility to ensure system security, system operators must ensure that generation and consumption remain in balance at all times. As shown in Fig. 4.1, different from the previously investigated frameworks where one entity combined market operation and duties of system security, in European systems, a TSO determines the
amount of AS capacity necessary for secure system operation. The procurement of AS products is done via an one buyer auction, independent from other market operations. Further, the TSO is responsible for the AS deployment with a balancing market as settlement framework. Thereby, the TSO is supported by a Balance Responsible Party (BRP) or several BRPs.

BRPs have the task of keeping their own portfolio balanced over a given timeframe (i.e. the settlement period) via the so called imbalance settlement mechanism. Each market participant can decide for itself whether to be a BRP. Besides grid tariffs, the imbalance market frameworks are a source of income for the TSO to cover the expenses of system services. However, these markets are exposed to several weak spots [81], [82], and [83]: First, non-market based components and prices from energy trade lead to an intransparent remuneration of AS capacity and deployed balancing energy. Socialization of costs through grid tariffs and a non market-based penalty system in the imbalance settlement without a locational component do not reflect the principles of cost causality and do not price reliable energy supply according to the individual valuation of it. Second, in a non market-based imbalance settlement setup, market participants may exploit market power through strategic action and market arbitrage. Market participants may find it beneficial to shift demand from energy trade to the imbalance market in order to save pro-
4.1. Introduction and Motivation

curement costs. Further, market participants may withhold own generation capacity in the energy market in order to avoid any imbalances in real-time. Both processes reduce energy market liquidity and give the possibility to exploit market power through scarcity conditions. Third, well-functioning intra-day and balancing management schemes are beneficial to ensure the economic efficient integration of renewable-energy sources [84]. A market-based integration of renewable energy sources requires the possibility to price imbalances according to the costs that they incur on the system. Further, BRPs with high shares of fluctuating renewable energy injection should not be penalized per se for the absolute value of deviations from the schedule but according to their willingness to pay to avoid fluctuations.

It can be argued that an economically efficient settlement mechanism for reserve capacity and reserve energy should be based on the following principles:

1. It should cover the true costs of the different types of AS capacity.

2. It should reflect the locational value of AS capacity when the grid is heavily loaded.

3. Charges should be based on the individual valuation of system services.

4. System participants who create imbalances should pay more giving them an incentive to reduce their contribution to these imbalances via investments in e.g. storage or demand response.

5. It should not include energy market components in order to avoid gaming behavior by the market participants.

In this chapter, an imbalance settlement market setup design, which covers these points is proposed. It uses the individual elasticity of demand for reserve capacity as proposed in ref. [82], and allocates charges for non event-based reserve capacity according to a Ramsey-type rule [85, 86]. This means that the payments are related to individual preferences. Balancing energy costs are recovered via a real-time market for balancing energy with the goal to reduce imbalance deviations. Additional fairness considerations, which modify the Ramsey-rule, e.g. in [87] and [88], are not considered.
4.2 Literature Review

As proposed in ref. [82, 89], the amount of procured reserve capacity is a function of the individual valuation of it. The authors of [90] highlight design issues of a market for energy imbalances based on real-time prices signals, such as the real-time dispatch method, the ancillary service auctions, and the settlement. Ref. [91] and [92] stress the necessity of reliability differentiated real-time pricing in order to achieve efficient market outcomes. A mostly descriptive discussion of the need for proper imbalance pricing based on market based components can be found in [93] and [94]. The authors of [80] and [82] develop a game theoretic framework to analyze the possible negative consequences of suboptimal incentive mechanisms in the balancing market. Reference [95] investigates the possibilities for strategic behavior in the Nordic balancing market using an agent-based model. The authors of [96] and [97] apply a cost-based method for the valuation of AS capacity and balancing energy and allocate fixed and usage costs using a non-linear tariff system.

4.3 Modeling Framework

4.3.1 Overview

Figure 4.2 puts the proposed settlement mechanism in the context of the electricity market. Energy, as well as event-based and non event-based reserves are traded on the day-ahead market and the prices for these ancillary services are determined. After the closure of an optional intraday market, which is not considered explicitly, the real-time balancing market determines the price of short-term balancing energy. BRPs take part in this process because of the need for non event-based reserve capacity and deployed reserve energy to compensate for deviations between their scheduled and their actual performance. A Balancing Service Provider (BSP) provides system services to the TSO. The TSO determines the amount of AS capacity needed based on security standards and procures this reserve capacity and the required deployed energy in a single buyer auctions. The BRPs get charged the costs of reserve capacity on the basis of a non-linear pricing scheme, which differentiates between the costs of event-based and non event-based reserves. Each BRP requires a different amount of balancing energy and
this amount is determined in part by the amount of flexibility resources (e.g. fast ramping generation, storage, and demand response) that it can muster.

![Diagram of Modeling Framework](image)

Figure 4.2: Modeling framework: First the procurement of traded energy and AS capacity in a day-ahead market takes place. The costs of event-based and non-event based AS capacity are settled. After a possible intraday trading period, a real-time balancing market is in effect. The costs of balancing energy for the consumer depend upon short-term balancing energy auctions which gives real time price signals.

This approach differs from the clearing framework proposed in chapter 2 in several ways:

1. The imbalance settlement framework for reserve capacity is independent from the amount of reserves procured by the TSO. Thus, the TSO still procures the amount of reserve capacity which is necessary for a secure system operation.

2. In the course of the settlement it only requires a willingness to pay curve for non event-based reserve capacity, and not for event-based reserve capacity. The latter one might be hard to establish due to the problem of dealing with low probability contingencies.

3. The market clearing is independent of the individual preferences of the balance responsibility parties for reserves.

The costs of deployed reserve energy are shared following the method in chapter 2. The demand for reserve energy of every BRP may vary, for example it depends upon the amount of storage or onsite generation the BRP has access to. Different from chapters 2 and 3, where the expected amount of deployed reserve energy is assumed to be a fixed share of the procured reserve capacity, the amount of deployed energy in this approach is uncertain.
4.3.2 Allocation of Reserve Capacity Costs

Following [86], an incentive compatible charge for event-based and non-event-based reserve capacity is achieved through a non-linear tariff system. The primal market outcome from a co-optimization problem of reserves and traded energy is used to calculate the optimal two-part capacity charge for event-based and non-event-based AS capacity, which ensures sufficient revenue for the TSO as a monopolistic service provider.

The costs that the TSO has to cover include the procurement cost of event-based AS capacity, $C^{\text{evt}}_{\text{cap}}$, the cost of non-event-based capacity, $C^{\text{noevt}}_{\text{cap}}$, and the additional commitment costs, $C^{\Delta\text{commit}}_{\text{Res}}$. A change in the commitment costs may result from the co-optimization of energy and reserves. For brevity, only the problem formulation for up-reserve capacity is stated. Similar formulations can be done for down-AS capacity. Different to chapter 2 and 3, the BRP is not stating its cost of avoiding deviations from the schedule. Instead, the BRP $j$ has a willingness to pay for non-event-based AS capacity at time $t$ of the form:

$$B^{\text{noevt},j,t}_{\text{Resup,cap}} = a^{\text{noevt},j,t}_{\text{Resup,cap}} + b^{\text{noevt},j,t}_{\text{Resup,cap}} Q^{\text{noevt},j,t}_{\text{Resup,cap}} - c^{\text{noevt},j,t}_{\text{Resup,cap}} Q^{\text{noevt},j,t}_{\text{Resup,cap}}^2,$$

(4.1)

where $a^{\text{noevt},j,t}_{\text{Resup,cap}} \geq 0$, $b^{\text{noevt},j,t}_{\text{Resup,cap}} \geq 0$, $c^{\text{noevt},j,t}_{\text{Resup,cap}} \geq 0$, and $Q^{\text{noevt},j,t}_{\text{Resup,cap}}$ is the quantity of non-event-based reserves demanded by BRP $j$ at time $t$. It implies a decreasing return of relying on services provided by the TSO. Therefore, as in the previous chapters, the BRP has a diminishing demand for externally provided backup capacity, either because of a low valuation of possible outages, flexible demand processes, or due to the installation of onsite backup capacity. The derivative of (4.1) with respect to $Q^{\text{noevt},j,t}_{\text{Resup,cap}}$ gives,

$$MB^{\text{noevt},j,t}_{\text{Resup,cap}} = Q^{\text{noevt},j,t}_{\text{Resup,cap}} = b^{\text{noevt},j,t}_{\text{Resup,cap}} - 2c^{\text{noevt},j,t}_{\text{Resup,cap}} Q^{\text{noevt},j,t}_{\text{Resup,cap}}^2.$$

(4.2)

A reformulation of (4.2), with $\frac{dB^{\text{noevt},j,t}_{\text{Resup,cap}}}{dQ^{\text{noevt},j,t}_{\text{Resup,cap}}} = \lambda^{\text{noevt},j,t}_{\text{Resup,cap}}$ gives:

$$MB^{\text{noevt},j,t}_{\text{Resup,cap}} = Q^{\text{noevt},j,t}_{\text{Resup,cap}} = b^{\text{noevt},j,t}_{\text{Resup,cap}} - 2c^{\text{noevt},j,t}_{\text{Resup,cap}} Q^{\text{noevt},j,t}_{\text{Resup,cap}}^2.$$

(4.3)

Eq. (4.2) states the inverse marginal willingness to pay for AS capacity as a function of the quantity demanded, $MB^{\text{noevt},j,t}_{\text{Resup,cap}}^{-1}$. On the other
hand, eq. (4.3) shows the marginal willingness to pay for capacity as a function of price, $MB_{Resup,cap}^{noevt,j,t}$.

The problem of cost allocation in case of AS capacity is stated as a weighted maximization of the profit of the TSO, $S_{TSO}$, and the surplus of the BRPs, $S_{BRP}$:

$$\max_{\vartheta_1 = \{x,u\}} (1 - \beta)S_{TSO} + \beta S_{BRP},$$

subject to

$$h_1(a, x, u) = 0,$$  \hspace{1cm} (4.5)

$$g_1(a, x, u) \leq 0,$$  \hspace{1cm} (4.6)

where $\beta$ is a weighting factor $\in [0,1]$. Eqs. (4.5)-(4.6) include no-loss constraint for the TSO, and the individual rationality of the BRP dependent upon its individual willingness to pay for event-based and non event-based reserves. Further, the amount of procured reserves is matched with the demand. Incentive compatibility is ensured, so BRPs reveal their true preferences about non event-based system services. Each BRP is therefore better off by stating its true valuation of AS capacity. All continuous decision variables in the set of decision variable $\vartheta_1$, $x$, are greater or equal to zero. Variable vector $u$ contains discrete variables and $a$ is a parameter vector. The complete formulation including the constraints (4.5)-(4.6), $h_1(a, x, u)$ and $g_1(a, x, u)$, is given in appendix B.3.3.

### 4.3.3 Allocation of Reserve Energy Costs

#### Imbalance Settlement in a Real-Time Energy Market

Real-time energy balancing can be modeled as a re-dispatch at time $t$ [90]:

$$\min_{\vartheta_2} \sum_{i=1}^{N_G} \sum_{s=1}^{N_S} MC_{Resup/dn,en,seg}^{noevt,i,s,t} G_{Resup/dn,en,seg}^{noevt,i,s,t},$$  \hspace{1cm} (4.7)

subject to

$$h_2(a, x, u) = 0,$$  \hspace{1cm} (4.8)

$$g_2(a, x, u) \leq 0,$$  \hspace{1cm} (4.9)
where

\[ \mathcal{G}_2 = \{ G_{\text{Resup/dn,en,seg}}^{\text{noevt,i,s,t}} \} . \]

The most recent re-dispatch prices or the average of the most recent prices are used for the imbalance settlement at the time instant of physical delivery [98]. This pricing scheme is ex-post and the demand for balance energy is inelastic. Variable \( G_{\text{Resup/dn,en,seg}}^{\text{noevt,i,s,t}} \) states the real-time up/down balancing energy production. Parameter \( MC_{\text{Resup/dn,en,seg}}^{\text{noevt,i,s,t}} \) states the marginal costs of up/down balancing energy production. Parameter \( MC_{\text{Resup/dn,en,seg}}^{\text{noevt,i,s,t}} \) states the marginal costs of up/down balancing energy in segment \( s \), of BSP \( i \), at time \( t \). Constraints \( h_2(x,u) = 0 \) includes the balance of the instructed and uninstructed deviations of all BRPs. Constraints \( g_2(x,u) \) include the capacity constraints for the generators resulting from the day-ahead clearing.

**Imbalance Settlement in a Reserve Energy Market**

In contrast to the pricing of imbalances based on energy market information, we propose a remuneration of reserve energy based on the BRP’s valuation of it. The system operator matches demand and supply for balancing energy and determines the prices of real-time balancing energy for the point of physical delivery. The difference to the real-time energy market framework presented in eqs. (4.7)-(4.9) is that,

- it differs explicitly between market operation and operations to keep system security, where the latter is the duty of the TSO. The framework therefore allows the separation of these two goals as currently done in most of the European market frameworks.

- it uses as a supply curve the offers from the BSPs which provide balancing energy. The balancing energy bid block of a BSP is bounded by the amount of AS capacity scheduled on a day-ahead basis.

- it considers an expected demand for balancing energy by the BRPs.

It is assumed that an individual BRP \( j \) has a demand for up/down balancing energy at time \( t \), \( MB_{\text{Resup/dn,en}}^{j,t} \), of the form:

\[
MB_{\text{Resup,en}}^{j,t} = \left( \frac{Q_{\text{Resup,en}}^{j,t}}{F_{\text{Resup,en}}^{j,t}} \right) e_{\text{Resup,en}}^{j,t} \quad (4.10)
\]
4.3. Modeling Framework

where $\epsilon_{j,t}^{\text{Resup,en}} = \frac{1}{\eta_{j,t}^{\text{Resup,en}}}$ with $\eta_{j,t}^{\text{Resup,en}} \in [-\infty, 0]$. Parameter $Q_{j,t}^{\text{Resup,en}}$ is the expected real-time deviation of BRP $j$ from the schedule at time $t$, $F_{j,t}^{\text{Resup,en}}$ is a positive factor and $\eta_{j,t}^{\text{Resup,en}}$ is the price elasticity for balancing energy. Formally, eqs. (4.7)-(4.9) can be extended as:

$$
\min_{\vartheta_3} \sum_{i=1}^{N_G} \sum_{s=1}^{N_S} MC_{i,s,t}^{\text{Resup,en,seg}} G_{i,s,t}^{\text{Resup,en,seg}} - \sum_{q=1}^{N_Q} MB_{q,t}^{\text{Resup,en,seg}} D_{q,t}^{\text{Resup,en,seg}},
$$

subject to

$$
\begin{align*}
&h_3(a, x, u) = 0, \quad (4.12) \\
&g_3(a, x, u) \leq 0, \quad (4.13)
\end{align*}
$$

where

$$
\vartheta_3 = \{ G_{i,s,t}^{\text{Resup,en,seg}}, D_{q,t}^{\text{Resup,en,seg}} \}.
$$

Parameter $MB_{q,t}^{\text{Resup,en,seg}}$ represents segment $q$ of the sum of all BRP balancing energy demand curves at time $t$, and $D_{q,t}^{\text{Resup,en,seg}}$ is the market clearing demand. The shown benefit function gives a constant price elasticity for deployed energy. This means that the percentage change of the marginal benefit of deployed energy in response to the amount of deployed energy stays constant. Other forms such as a quadratic cost function, or linear cost function are conceivable. It has to be noted that those demand functions have different price elasticities depending upon the point of operation. This function has been chosen because it combines aspects of a quadratic benefit functions with a lower number of parameters of freedom, namely two. The evaluation of which cost function fits best depending upon the assumed technology for balancing and the market environment, is out of the scope of this thesis. Constraints $h_3(x, u) = 0$ and $g_3(x, u) \leq 0$ represent the balance of generation and demand, and the generation limits for balancing energy respectively. Given this framework, it has to be considered (a) how the demand for reserve energy is determined, and (b) that physically only the aggregation of all deviations matter in terms of deployed reserve energy. Therefore, the method for settling costs of public goods in a Lindahl equilibrium and preference revelation as presented in chapter 2 is applied. For every BRP a demand function for reserve energy with constant price elasticity is assumed.
4.4 Simulation Setup

4.4.1 Test System

The 9-bus test system as shown in Fig. 4.3 is used. Three BRPs at nodes 5, 7, and 9 are assumed. The BSPs are located at busses 1, 2, and 3. A small system has been chosen in order to be able to highlight how payments change with the preferences the BRP. However, bigger test systems are conceivable but do not change the argument of the chapter. The BRPs have predefined preferences for AS capacity and balancing energy. Further data are given in the appendix A.3. The approach was implemented in Matlab using the interface YALMIP and IBM ILOG CPLEX as the solver [55], [56].

![Diagram of considered test system with BRPs at busses 5, 7, and 9, BSPs at busses 1, 2, and 3.](image)

Figure 4.3: Considered test system with BRPs at busses 5, 7, and 9, BSPs at busses 1, 2, and 3. In the course of the simulations, we consider transmission limits between 4-5 and 8-7.

Fig. 4.4a, 4.4b, and 4.4c show the scheduling in case of no congestion in the network. As shown Fig. 4.4b and 4.5b it is assumed that the demand for event-based reserves by the system operator is 20% of the unit with the largest production. The demand for non event-based reserve capacity, $R_{\text{noevt},t}^{\text{Req},\text{Resup/dn,cap}}$, is determined via chance constrained optimization as shown in (3.17). The scenarios for the deviations with are then covered by probabilistic bounds are drawn form a normal distribution function with zero-mean and a standard deviation of 5% of the total load. As shown in Fig. 4.5a, 4.5b, and 4.5c, congestion leads to a higher utilization of the most expensive generator $G_3$ for energy production. Additionally $G_2$ is not contributing to reserve capacity. This has an impact on the cost recovery.
4.4. Simulation Setup

Figure 4.4: Schedule of generators in case of no congestion,
(a) Traded Energy,
(b) Event-based up reserves,
(c) Non event-based up reserves
Figure 4.5: Schedule of generators in case of congestion,
(a) Traded Energy,
(b) Event-based up reserves,
(c) Non event-based up reserves
4.4.2 Benchmark Approaches

The approach is compared with versions of one- and two-price systems as explained in the following. All benchmark mechanisms are ex-post pricing mechanisms and do not give a real-time price signal to the BRP. In one-price schemes, payments for deployed reserve energy are independent from the imbalance status of the system. They are in general preferable to two-price schemes, which pursue an asymmetric imbalance penalization dependent upon if the system’s net power balance is positive or negative. An example of an one-price scheme is the imbalance settlement mechanism in Switzerland [99]. Further, capacity remuneration is important in terms of a long-term supply of adequate AS capacity [82]. Different from the approach in section 4.3.3, the remuneration can also be done either via a uniform cost socialization and grid tariffs, a periodical fee, or as an additional component to the balancing energy payments. For example, the imbalance settlement schemes in Austria and Germany incorporate an additive component dependent upon the extend of real-time deviations [100, 101]. However, these forms of remuneration are not transparent since they are established on heuristic rules and may create too few or excess payments to the TSO for capacity reservation.

All approaches are evaluated given the same set of imbalances. The physical imbalances of every BRP $j$, are drawn from a normal distribution function,

$$Q_{Resup, en}^j \sim max(0, \mathcal{N}(\mu, \sigma^2)),$$

$$Q_{Resdn, en}^j \sim abs(min(0, \mathcal{N}(\mu, \sigma^2)))$$

where $\mu = 0$ and $\sigma^2 = 1\%$ of the actual demand of the BRP, $D_{En,seg}^{j,t}$. A simple Monte-Carlo simulation for all the approaches is done and the expected payments in case of imbalances are assessed.

**Symmetric-Settlement (Sym)**

Table 4.1 shows that the imbalance charge is computed depending upon the net position of the BRP and the overall system [82]. For example, in the upper left box, the TSO pays the BRP for excess production. In the lower left box the BRP has to pay a penalty for a negative generation demand mismatch. The settlement does not include additional penalty factors.
Chapter 4. Decentralized System

Table 4.1: One price system with no additional penalty factors.

<table>
<thead>
<tr>
<th>BRP/System</th>
<th>Long</th>
<th>Short</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long</td>
<td>0.5(\lambda^{n,t}<em>{\text{En,DA}}Q</em>{\text{Resup,en}}^j)</td>
<td>0.5(\lambda^{n,t}<em>{\text{En,DA}}Q</em>{\text{Resup,en}}^j)</td>
</tr>
<tr>
<td>Short</td>
<td>-1.5(\lambda^{n,t}<em>{\text{En,DA}}Q</em>{\text{Resdn,en}}^j)</td>
<td>-1.5(\lambda^{n,t}<em>{\text{En,DA}}Q</em>{\text{Resdn,en}}^j)</td>
</tr>
</tbody>
</table>

Parameter \(\lambda^{n,t}_{\text{En,DA}}\) is the day-ahead clearing price for traded energy at node \(n\) and time \(t\), and \(Q_{\text{Resup/dn,en}}^j\) is the real-time up/down imbalance, where \(Q_{\text{Resup/dn,en}}^j \geq 0\). The approach Sym has the advantages of a one-price system as stated previously. However, it includes components from energy market operation and is therefore prone to gaming.

Asymmetric-Settlement (Asym)

Table 4.2 shows the case of an asymmetric settlement [82]. Additional penalty factors depending upon the contribution to the overall system balance are assumed.

Table 4.2: Two price system with distinction between supporting and counteracting balance state of the BRP.

<table>
<thead>
<tr>
<th>BRP/System</th>
<th>Long</th>
<th>Short</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long</td>
<td>(\lambda^{n,t}<em>{\text{En,DA}}\frac{Q</em>{\text{Resup,en}}^j}{(1+0.25)})</td>
<td>(\lambda^{n,t}<em>{\text{En,DA}}Q</em>{\text{Resup,en}}^j)</td>
</tr>
<tr>
<td>Short</td>
<td>-(\lambda^{n,t}<em>{\text{En,DA}}Q</em>{\text{Resdn,en}}^j)</td>
<td>-(\lambda^{n,t}<em>{\text{En,DA}}(1+0.4)Q</em>{\text{Resdn,en}}^j)</td>
</tr>
</tbody>
</table>

The approach Asym has the characteristics of a two-price system as stated previously. This approach also incorporates energy market components and due to its weighting factors creates additional incentives to use the balancing market as a mechanism to circumvent high costs in the energy market trading.

Settlement based on Costs of Deployed Energy (En, EnCap)

The previous settlement schemes (a) did not include the price of balancing energy, but the day-ahead price for traded energy, and (b) did not include the remuneration of the AS capacity. In the imbalance settlement scheme shown in Table 4.3, the price for up/down balancing energy is considered (En). Further, reserve capacity costs are considered
4.4. Simulation Setup

through an additive component (EnCap). The additive component does not depend upon the net position of the BRP or the control area. The capacity component per BRP and time instant $t$ comprises the commitment costs of providing reserves, the AS capacity costs for event-based AS, and the costs non event-based AS which are socialized among all BRPs,

$$cap^{j,t} = \frac{1}{N_L} \left( C_{\Delta \text{commit}} + C_{\text{AScap}}^{\text{evt}} + C_{\text{AScap}}^{\text{noevt}} \right) \frac{1}{N_T}. \tag{4.16}$$

However, this setup still does not fulfill the economic requirements of cost allocation according to cost causality.

Table 4.3: Imbalance settlement with additional capacity remuneration.

<table>
<thead>
<tr>
<th>BRP/System</th>
<th>Long/Short</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long</td>
<td>$\lambda_{\text{Resup/dn,en}}^t Q_{\text{Resup,en}}^j (-cap^{j,t})$</td>
</tr>
<tr>
<td>Short</td>
<td>$-\lambda_{\text{Resup/dn,en}}^t Q_{\text{Resdn,en}}^j (-cap^{j,t})$</td>
</tr>
</tbody>
</table>

Swiss-System Settlement (Swiss)

In Table 4.4 a simplified version of the imbalance settlement framework of the Swiss TSO is used. As in the previous symmetric settlement schemes, the imbalance charge is independent of the net position of the overall system, however it still incorporates traded energy prices and in a small market may be prone to gaming.

Table 4.4: Simplified imbalance settlement scheme of Switzerland. The BRPs settlement is independent from the net position of the TSO.

<table>
<thead>
<tr>
<th>BRP/System</th>
<th>Long/Short</th>
</tr>
</thead>
<tbody>
<tr>
<td>Long</td>
<td>$(A + P_1)\alpha_1 Q_{\text{Resup,en}}^j$</td>
</tr>
<tr>
<td>Short</td>
<td>$(B - P_2)\alpha_2 Q_{\text{Resdn,en}}^j$</td>
</tr>
</tbody>
</table>

where

$$A = \min(\lambda_{\text{En,DA}}^{n,t}, \lambda_{\text{Resup,cap}}^{n,t}), \tag{4.17}$$

$$B = \min(\lambda_{\text{En,DA}}^{n,t}, \lambda_{\text{Resdn,cap}}^{n,t}). \tag{4.18}$$
Parameter $\lambda_{Resup/dn, cap}^{n,t}$ is the day-ahead clearing price for non-event up/down-reserve capacity at node $n$ at time $t$. The parameters values $P_1 = 100 \frac{\text{m.u. MWh}}{\text{MWh}}$, $P_2 = 50 \frac{\text{m.u. MWh}}{\text{MWh}}$, $\alpha_1 = 1.1$, and $\alpha_2 = 0.9$ follow from [99].

## 4.5 Results

### 4.5.1 Recovery of Capacity and Energy Costs

The approach is tested in terms of recovery of costs of procured reserve capacity and reserve energy. Fig. 4.6-4.7 shows the ratio between the charges imposed in total on the BRPs and the costs of procured up/down reserve capacity comprising event-based reserves, non event-based reserves, and additional commitment costs, dependent upon the factor $\beta$ in eq. (4.4). The shown scenarios include,

- no congestion in the network (Upcap$_{nc}$ and Dncap$_{nc}$),
- no congestion and no incentive compatibility constraints (Upcap$_{ncnI}$ and Dncap$_{ncnI}$),
- congestion in lines 4-5 and 7-8 (Upcap$_c$ and Dncap$_c$).

Fig. 4.6 shows the case where the TSO is not allowed to make a loss given the sum of all payments and charges over the whole time period of 24 hours. Fig. 4.7 shows the case where the TSO is not allowed to make a loss in every time period of the optimization horizon. As seen at $\beta = 0.5$, the BRPs are therefore getting charged slightly more conservative. In both cases, an increase of the weighting factor $\beta$ greater than 0.5 leads to a reasonable cost recovery for AS capacity. However, the existence of an incentive compatibility mechanism circumvents an efficient cost recovery. An intuitive trade-off between the amount of truthful information exchange and efficiency in the market solution can be seen. The existence of network congestion additionally leads to efficiency losses in case of incentive compatibility constraints. The extent of these losses is dependent upon the system setup.

Table 4.5 lists the ratio of imbalance payments to costs of balancing energy in the benchmark approaches in case of no congestion (nc) and congestion (c) (nodal pricing framework). The costs of approaches EnCap$_{nc/c}$ also include the costs of reserve capacity (event-based reserves, non event-based reserves and additional commitment costs). The
4.5. Results

Figure 4.6: Cost recovery of AS capacity dependent upon a weighting of the TSO surplus and BRP surplus. The TSO is not allowed to make a loss in sum over the whole optimization horizon. The shown scenarios comprise up and down reserve capacity and no congestion in the network (Upcap_{nc} and Dncap_{nc}), no congestion and no incentive compatibility constraints (Upcap_{ncnI} and Dncap_{ncnI}), and congestion in lines 4-5 and 7-8 (Upcap_{c} and Dncap_{c}).

Figure 4.7: Cost recovery of AS capacity dependent upon a weighting of the TSO surplus and BRP surplus. The TSO is not allowed to make a loss in every time period of the optimization horizon. The shown scenarios comprise up and down reserve capacity and no congestion in the network (Upcap_{nc} and Dncap_{nc}), no congestion and no incentive compatibility constraints (Upcap_{ncnI} and Dncap_{ncnI}), and congestion in lines 4-5 and 7-8 (Upcap_{c} and Dncap_{c}).
outcome for the proposed method is shown in Fig. 4.10. The proposed approach is in terms of cost recovery for reserve energy comparable to approaches of symmetric and asymmetric settlement. However, the benchmark approaches do not assure payments dependent upon the individual preference of the BRP and its willingness to avoid real-time deviations. Further, the ex-post settlement of the benchmark approaches does not contain any real-time price component.

Table 4.5: Sum of payments of BRPs in % to the total costs of balancing energy (...∗ comprises also the costs of AS capacity).

<table>
<thead>
<tr>
<th>% Cost Recovery</th>
<th>no congestion</th>
<th>congestion</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sym</td>
<td>89.64</td>
<td>7.36</td>
</tr>
<tr>
<td>Asym</td>
<td>104.32</td>
<td>8.44</td>
</tr>
<tr>
<td>Swiss</td>
<td>182.78</td>
<td>106.91</td>
</tr>
<tr>
<td>En</td>
<td>300.00</td>
<td>299.88</td>
</tr>
<tr>
<td>EnCap</td>
<td>152.96∗</td>
<td>153.72∗</td>
</tr>
</tbody>
</table>

Further, whereas EnCap also covers part of the costs for reserved capacity, compared with Fig. 4.6 and Fig. 4.7, it does not do it efficiently and not incentive compatible with the preferences of the BRP. Clearly, the stated ratios vary quantitatively with the assumed cost structure of the system and the assumed congestion.

4.5.2 Impact of Preferences on Energy Payments

The demand for energy $MB_{\text{Resup/dn,en}}^{j,t}$ is parameterized as follows: Scaling factor $F_{\text{Resup/en}}^{j,t}$ is constant over time and is 0.0166 times the maximum of the sum of generation over the entire time horizon. The term $Q_{\text{Resup/dn,en}}^{j,t} \times \frac{1}{F_{\text{Resup/dn,en}}^{j,t}}$ varies between $\frac{1}{F_{\text{Resup/dn,en}}^{j,t}}$ MWh and five MWh. These values are chosen to be numerically comparable to the benchmark approaches. It is assumed that BRP one changes its elasticity of demand according to,

$$\eta_{\text{Resup/dn,en}}^{1,t} = 0.035 \times (n - 1),$$

for every time instant $t$ where $n$ is a tuning variable. Fig. 4.8 and 4.9 show the demand curves for balancing energy where BRP 1 changes its preferences. Fig. 4.10 shows the total recovery of costs for balancing
4.5. Results

Figure 4.8: Highest stated marginal willingness of BRPs, BRP\(_1\), BRP\(_2\), and BRP\(_3\) to pay curves to pay for energy in 20 segments. The sum of these demand curves gives \( \overline{MB} \). \( \max_t \) states the maximum over all time instants \( t \). The rise in the last segment is due to numerical inaccuracy but has no influence on the simulation results.

Figure 4.9: Lowest stated marginal willingness of BRPs to pay curves to pay for energy. \( \max_t \) states the maximum over all time instants \( t \).

energy dependent upon the individual elasticity of demand of balancing energy per BRP. \( \text{Li}_{\text{nc}} \) and \( \text{Cl}_{\text{nc}} \) are the total payments in case of a Lindahl clearing, \( Li \), or a Clarke mechanism, \( Cl \), in presence of no congestion, \( nc \), or congestion, \( c \). An incentive payment via Clarke-Groves leads in general to higher payments in case of imbalances. However,
total payments stay more or less constant independent of the preference change of BRP 1. Note that no nodal-pricing scheme for balancing energy was assumed since network congestion has already been priced in connection with the AS capacity reservation.

![Figure 4.10: Cost recovery of costs of deployed reserve energy dependent upon a change in preferences via the control variable n for reserve energy by BRP 1. The higher n the higher the higher the elasticity of the willingness to pay curve of BRP 1. Li, and Cl, stand for a Lindahl or Clarke type clearing in presence of no congestion, nc, no congestion and no incentive compatibility constraints 4.4 - 4.6, ncnI, or congestion, c.](image)

Fig. 4.11a and 4.11b show the change of BRP-wise payments in case BRP 1 changes its preference for balancing energy. Since the total payments stay constant as seen in Fig. 4.10, the payments of the other BRP have to rise. This may lead to a general tendency that BRPs try to avoid the use of balancing energy in a non-cooperative setting.

### 4.5.3 Impact of Congestion on BRP Payments

Fig. 4.12 and 4.13 show the absolute BRP-wise change in payments for balancing energy and AS capacity in case with and without congestion. The Clarke-Groves mechanism leads to a reduction of preference misrepresentation and leads to relatively higher payments of BRP 2 and 3 compared with the Lindahl payments. Costs of non event-based and event-based reserve capacity are in case of no congestion carried by BRP 1 and 2. The share of payments for non event-based reserves shift in case of congestion and the resulting change in nodal prices to BRP 1.
4.5. Results

Figure 4.11: Ratio of payments compared with base case ($n = 1$ is equal to lowest elasticity) of BRPs dependent upon a rising price elasticity of BRP 1 in case of (a) Lindahl clearing, (b) Clarke Payment.

However, due to the rationality constraints for the BRPs, BRP 2 has to carry the major share of event-based reserves. BRP 3 has the lowest payments for both capacity and energy, which gives it the lowest priority if the system runs out of reserves and interruptions may be necessary.
Figure 4.12: BRP payments for deployed energy and reserve capacity dependent upon BRP: (a) Per Unit, (b) Fixed
4.5. Results

Figure 4.13: BRP payments for deployed energy and reserve capacity dependent upon BRP in case of congestion: (a) Per Unit, (b) Fixed. Due to congestion and the change in the LMP prices the variable payments change. However, due to budget constraints fixed payments are also swapped between BRPs.
4.6 Summary

This chapter proposed a novel mechanism to allocate costs of ancillary service capacity and balancing energy based on the willingness of balance responsible parties to pay for reserve capacity and reserve energy. A cost recovery mechanism for reserve capacity costs was presented where excess charges may be paid due to incentive compatibility considerations. However, the proposed approach enhances market efficiency since balancing services are remunerated and provided based on the individual valuation of reserves. In this market framework two different entities such as a market operator and a system operator can operate and it is therefore also valid for power market setups in continental Europe. However, different from current setups in European power systems, it provides

- a real-time price signals for balancing energy. It therefore may be seen as a hybrid form of centrally organized markets with a system operator, as in US power systems, and a decentralized self-scheduling scheme which is predominant in continental Europe.

- financial incentives for decentralized netting of imbalances and simultaneously performs at least as good to various benchmark approaches tested in this chapter.

- no incentives to game the imbalance settlement market and the market for traded energy since no energy market components are included in the settlement process for imbalances.

Finally, the proposed approach is able to deal with locational price signals, which is a crucial market design feature when it comes to limited capacity in transmission.
Chapter 5

Closure Part I

Whereof one cannot speak, thereof one must remain silent. Ludwig Wittgenstein, Tractatus Logico-Philosophicus

This chapter concludes the first part of the thesis by summarizing the work, drawing conclusions and suggesting open issues for future work

5.1 Summary

The first part of the thesis proposed a mechanism which allows the efficient allocation of ancillary service costs based on the theory of public goods, and externalities. The general concepts were illustrated by classification of the type of reserves in event-based reserves and non event-based reserves.

Event-based reserves, i.e. contingency reserves, are needed for events, which occur with low probability. These kind of events are hard to predict, and are even with high cost effort never completely preventable. Consumers were assumed to have different preferences about the amount of reserves they would like to have as backup capacity in order to determine an economic efficient cost sharing rule. Non event-based reserves are needed for events, which occur with high probability and market participants can have possibilities to avoid the reservation and deployment of such reserves. Therefore these reserves may be treated as an
externality, which has to be priced. Several applications of the proposed cost sharing rule were shown, including market designs with a centralized entity, which handle market operation and duties of system security, and a decentralized setup, where market operation and system security are accomplished by two different entities. Additionally, a practical application for a market-like integration of renewable energy in-feed has been shown.

5.2 Conclusion

Simulation results and the assessment of different market setups have disclosed several issues. General results are that:

- The socialization of costs of reserve capacity and deployed energy does not provide financial incentives for a decentralized treatment of system imbalances. However, a cost allocation mechanism is an essential part to create a more efficient and complete market in a system setup with a high penetration of low marginal cost fluctuating feed-in. An efficient cost sharing mechanism raises significantly the complexity of the market design and exchange of, possible sensitive, information. Further, the tuning of a preference revelation mechanism requires extensive tests with system data. In case of low costs of reserve power provision, these efforts, and hence the transaction costs of implementing such a market, may exceed the benefits. However, as observed in several European countries, the costs of system services is rising compared with the costs of energy.

- A promotion of renewable energy generation has to consider market aspects. Thereby, the welfare impact of an adaptive support scheme has to be individually assessed. The support of renewable energy production via an adaptive support scheme and externally triggered demand response may counteract and jeopardize the financial impact of one or the other.

From a modeling perspective:

- Cost sharing mechanisms require a significant number of intermediate steps in order to evaluate the individual preference of a
public good such as secure electricity supply. However, the proposed methodology is decomposable and parallelizable which can reduce the computational effort for large systems.

- The theoretic validity of a preference revelation mechanism has to be assessed in models in order avoid too low or high incentive-based payments.

5.3 Outlook

Several starting points for future research are provided. A chapter-wise overview of the first part of the thesis including further aspects with regard to the applied methods, the numerical assessment, and the practical implementation is presented below. This list is not exhaustive but highlights immediate points of open research:

- **Chapter 2:** The method in the thesis is based on the theoretic foundations of private goods and public goods. Concept-wise an extension of the method according to the theory of club goods is conceivable. Club goods are essentially only free for a certain class or fraction of individuals, which means that they are excludable. However, as more members of the club use the good it becomes rivalrous/congestible.

  An essential extension would be the application of the proposed framework to a real system. In particular the implementation of preference revealing mechanisms in practice and the comparison with approximations is of interest and requires tests with data from real systems. The validation of the numerous parameters, which are necessary for simulation purposes requires assessments from practice.

  It has been assumed that loads are aggregated in order to influence the market outcome through the aggregated flexibility in terms of reserve requirements. Therefore an extension of the model in terms of assessment of optimal aggregation to make the market mechanism work is of interest.

  From a computational point of view, an enhancement of the computational speed of the proposed mechanism through its decomposable structure is necessary to be applicable for large systems.
• **Chapter 3**: Besides changes in the cost structure, also changes in the system structure, e.g. numerical assessment of contingency considerations, are of interest.

A comparison with other support schemes such as direct marketing, and other feed-in premiums under consideration of a proper intra-day market design is of high interest in order to assess further advantages, disadvantages, and limits of the proposed approach.

• **Chapter 4**: From a methodological point of view, the large scale approximation of combinatorial optimization problems is subject to future research. Further, similar to chapter 2, real-world tests of the approach with regard to its practicability in behavioral experiments is of high interest.
Part II

Demand Response for System Services
Chapter 6

On Market-Like Incorporation of Demand Response

*Make everything as simple as possible, but not simpler.* Albert Einstein

*People from distinct disciplines view demand response differently. In this chapter options for demand response are reviewed and the engineering and economic implications associated with three specific cases, (1) real time pricing, (2) dispatch-based control via an aggregator participating in wholesale markets, and (3) direct participation in energy markets are considered. This chapter is based on ref. [102], [103] and [104].*

### 6.1 Introduction and Motivation

The previous chapters focused on the wholesale market design of ancillary service markets. Thereby, the influence of demand flexibility in avoiding imbalances in the system has been highlighted without making more specific statements about how this flexibility can be achieved. In the following chapters, the market design for ancillary service provision on a retail-level is investigated. In particular, the design of the interface between the consumer and the wholesale level, in order to balance
Engineers and economists view demand response (DR) differently: either seeing DR as a mechanism to improve electricity markets or seeing it as a new control variable that can enhance power system reliability and security. Clearly the engineering and economic issues are related. DR is defined by the U.S. Department of Energy (DOE) as “a tariff or program established to motivate changes in electric use by end-use customers in response to changes in the price of electricity over time, or to give incentive payments designed to induce lower electricity use at times of high market prices or when grid reliability is jeopardized” [15]. Within each of these categories, price of electricity and incentive payments, there are many ways to design a DR program, and there is disagreement about which designs fit ”best” to fulfill a specific purpose.

In this chapter, options for approaching electric loads for DR for ancillary services are qualitatively assessed. Three examples are presented, giving engineering and economic arguments for and against each. Different from chapters 2-4, DR is in the following defined as the active provision of reserves from the demand side. In other words, system services are sold as an additional supply in an auction process. However, this straightforward form of demand side participation can also be translated into the DR concept used in the previous chapters, specifically into,

- the establishment of a marginal benefit curve for reserves, which is the result of a loss of welfare due to unscheduled interruptions of supply,

- the establishment of an individual marginal cost curve for reserve capacity to reduce fluctuations in injection or demand.

In the following, some key issues which relate to engineering as well as economic aspects are mentioned with regards to a DR market framework for ancillary services [102] and [105]:

1. Speed of Response: A key issue is the frequency and lead-time of the DR signal and the speed of the response. In case of peak load shedding, loads usually have to shift demand for several hours. However, to provide frequency response, loads needs to receive continuous frequency signals and respond quickly and
6.1. Introduction and Motivation

continuously. The timescale of the signal and response is related to the service provided. Slow DR does not have to be perfectly predictable or reliable since other power system resources could be called upon to compensate for unexpected DR results.

2. Privacy Concerns: The deployment of digital meters has raised a number of privacy concerns with consumers. Detailed traces of their time series of electricity consumption are considered to be private information. Participation in certain types of DR programs requires exchange of information with other DR actors [106]. In contrast to digital metering, DR contracts can incorporate user preferences for privacy.

3. Decision and Choice Processes: Another consumer concern is freedom of choice; different DR program designs give participants different levels of choice. For example, direct load control involves up front choice in contract design but little choice in real-time (unless some level of choice is part of the contract). Pricing and market participation give more real-time choice, though market outcomes can be undesirable for customers and a system operator. Thus the dynamics and incentive compatibility of social choices in case of real-time pricing is a complex issue.

4. Rewards: One major concern with regard to incorporation of consumers in market operation is fairness, which can take many forms. For example, with locational prices (either via dynamic pricing or as a result of bidding) two customers with exactly the same economic preferences may face different prices because of grid congestion, a physical power system issue that they have little potential to affect, at least in the short-term.

5. Complexity: The costs associated with economic interactions between many players are transaction costs. In case of a commodity good in a competitive framework, the willingness to pay for it is equal to the marginal cost of provision in equilibrium. The overconsumption of reliability, a public good, creates market distortions as discussed in the previous chapters. Both, centralized and decentralized market frameworks require a bundle of additional arrangements to keep them working, and therefore might come with high transaction costs.
6.2 Price Signals

Fig. 6.1 shows schematically that loads receive flat fixed rates, the retailer, utility, balance responsible parties, or aggregator sends customers dynamic prices that reflect system conditions. Prices are formed based on the outcome of the wholesale markets and sent to the loads on the same interval as the market closing, which could be hourly to practically instantaneously. Prices could differ by location or be the same for the whole system. The customers respond (or not) to the prices in any way they want.

Price signals give customers the opportunity to pursue their own optimization, which is based on their own utility functions, allowing decentralized decision processes. This is efficient since, in theory, the decentralized entity knows itself and its environment best and this assumption is usually the basis of a market. Price signals have two major advantages. First, demand units are not obliged to make any private information public. The communication is one-directional. Second, demand units can individually take into account short- and long-term decisions in their price response, which creates efficient consumption and investment behavior. However, customers which are exposed to highly volatile prices could experience financial losses if they are unable to respond properly, creating high risk to individuals.

Power systems require planning since traditional resources take time to respond to dispatch commands. If it can be assumed that customers have quasi-linear utility functions (i.e. linear in one argument), resulting in an inverse demand function that is also a marginal willingness-to-pay
function, then a well defined response exists. However, this assumption may be not valid for two reasons: First, the primary concern of the consumer is not the good electricity itself but the service it provides, and second, price signals may have positive feedback effects leading to chaotic system behavior and bifurcations in prices. It is questionable if individual preferences for services, which have electricity as input factor, fulfill rationality, monotonicity, local non-satiation, convexity, and continuity [14]. It could be argued that uncertainty in the individual decision making is flattened out through aggregation, which leads to a probability distribution and an expected answer. However, the assumption about some form of aggregation leads to the question of how big such an aggregation unit is ideally and how such an aggregation again enables the financial reward for the individual. This has several further implications, which affect power system operation in terms of financial risk management and operational security. The entity sending the price signals faces the problem that it has to assume a certain consumption behavior from the demand side without the possibility of accurately predictable adjustment processes via price signals. This imposes high financial risks for the entity, i.e. the TSO, since in the worst case it faces uncertainty in procurement and deployment of system services. Operational security of power systems implies reliable countermeasures in case of emergency events. Given these concerns, price signals may not fulfill these requirements.

The second concern requires a dynamic economic analysis. Based on [107] an illustrative example is presented: Assume that demand at time $t$, $D_t$, depends on the actual price at time $t$, $\lambda^t$. Further, assume that supply is based on expected prices and these expectations are based on prices in the previous period $\lambda^{t-1}$. The demand (D)/supply (S) model then becomes:

$$D_t = a - b\lambda^t,$$
$$S_t = c + d\lambda^{t-1}, \quad (6.1)$$

with the equilibrium condition: $D_t = S_t$. After reformulation this system of equation can be rewritten as:

$$\lambda^t = \frac{a - c}{b} - \frac{d}{b}\lambda^{t-1}, \quad (6.2)$$

where dependent upon the system parameters $a, b, c, d$ the slope of $L = -\frac{d}{b}$ in Fig. 6.2 is different and hence the process of price convergence. Fig. 6.2 shows three different cases of price behavior for the
Figure 6.2: Price dynamics in case of different mappings of the supply/demand curve, $L$. $E$ represents the equilibrium condition $\lambda_t = \lambda_{t-1}$:
(a): Stable price movement,
(b): Instable price movement,
(c): Cycling price movement, Source: [107], p. 339.

case that price expectation relies on past information [107]. As shown, even simple systems can experience price limit cycles and instabilities. Of course, if this model is augmented with non-linear characteristics as done in [108], chaotic behavior is even more likely to occur. The presented model only comprises past information about price signals. Dampening effects through the inclusion of more information in the price signal are possible. Nevertheless, recent work has found that DR via price signals can lead to instabilities, which could lead to power system instability [109, 110, 111]. The dissemination and processing of necessary amounts of information results in costs with regard to the system design, and may lead to a rise in transaction costs.

On the one hand, responding to price signals requires loads to be capa-
able of making economic decisions, likely via optimization and controls software. For residential consumers to minimize their costs, they need good load models and forecasts of ambient conditions, energy usage, etc. Since households solve relatively small individual optimization and control problems, they can use high fidelity models that take into account their specific preferences, while still keeping the problem computationally tractable. This allows customers to use the full flexibility of their resources. As mentioned above, if loads do not behave as expected when participating in slow DR other resources can step in; however, if fast DR resources are unpredictable and unreliable there may be a problem, because other resources may be too slow to compensate. Price response gives essentially no reliability guarantee and so, from an engineering perspective, it is best suited to slow DR.

6.3 Price/Quantity Bidding by Individual Loads

As shown in Fig. 6.3, individual loads submit price/quantity bids directly to the ISO/TSO for optimization against all other resources in the market. The dispatch problem considers the physical constraint of the power system. The timescale of the markets could be days to minutes to instantaneous.

![Diagram](image)

Figure 6.3: Consumers optimize their energy consumption and submit price/quantity bids for reserves to the market platform.

At first sight, individual decentralized bidding processes should result in efficient electricity markets. Decentralized optimization achieves the
same benefits as discussed for price signals. In presence of a functioning legal and regulatory framework loads bidding into markets lead to market efficiency.

However, there are several concerns with this approach. First, the implementation and enforcement of rules and responsibilities in the case of undesired market behavior, for example the lack of an equilibrium, may not be easy to achieve. Complete markets through additional market products like hedging and insurance may be required to keep the market liquid. Second, even though a complete decentralized market process may reduce current concerns in power systems operation like imperfect competition, their impact on other forms of possible market failures must be investigated. Third, customers with the same economic preferences may experience different outcomes, because of the physical constraints of the power grid and this could cause feelings of unfairness. Finally, DR units which can shift energy consumption over time operate as storage units, with an energy capacity. Conventional generators do not have or only have large binding energy constraints, i.e. hydro storage, and so they usually bid in terms of power only. For a complete market in short term operation, loads should be able to bid both in terms of power and energy. As with real time price signals, individual bidding allows loads to do their own optimization. However, in this case, they also need to set their own bidding strategies. The price/quantity bids would reflect real DR capabilities since the loads themselves make the bids. Therefore, the loads must be capable of making forward-looking bids. These tasks may make market participation for some types of individual loads difficult. Further, communication requirements will be "extensive" to send individual load bids to markets, especially for fast-timescale markets. Additionally, from a system perspective, it would be difficult and perhaps impossible to optimize the generator and load bids because the dispatch formulation including all bids and physical system constraints would be enormous and likely unsolvable [112].

6.4 Direct Load Control and Contract-Based Rewarding

6.4.1 General Analysis

Fig. 6.4 shows that this approach assumes existing power market structures but here individual loads do not receive dynamic prices. Instead,
an aggregator participates in a market run by the ISO and the aggregator coordinates the behavior of the loads via direct load control (DLC). DLC broadly means that control actions (set point variations, switching commands, etc.) are pre-defined via a financial contract. In this thesis the aggregator may constitutes as intermediate in two different ways, as an additional third-party entity, or as coalition of loads.

DLC reduces financial risks for individual consumers, BRPs, and ISO/TSO, because it enables well-defined response to critical systems states. Therefore, it reduces the transactions costs induced by near real-time market frameworks. While customers have some choice in the contract design, this set-up removes the customer’s ability to make real-time choices, unless they are allowed within the contract.

From an economics perspective there are several concerns with this set-up. First, it would be desirable to minimize the amount of private information required to enable contract enforcement, while at the same time encourage truthful statement of individual preferences. These issues can be addressed through mechanism design as shown in the following chapters. Second, DR contracts should provide both sufficient incentives for high consumers participation and profitable aggregator business models. Sufficient incentives for participation relates directly to the problem of potential free-riders, who gain from a reliable power system without loss of comfort and low prices. Further, the amount of DR supplied, without external enforcement (via measurement and validation) by the aggregator, is a crucial cornerstone for a wide acceptance rate. Since the aggregator controls the loads it has to have an understanding of their capabilities, and how those capabilities change over
Chapter 6. Incorporation of Demand Response

time. Therefore, it is likely that selected information will need to be sent to the aggregator periodically, to ensure observability and adequate contracting. Even with this information exchange the aggregator knows less about specific load capabilities unless all information is exchanged in near real-time. Additionally, for tractable optimization and control, the aggregator may have to use simplified models. So DR via aggregator may be less optimal than that via optimization by individual loads. Engineering tools including system identification, state estimation, and control can help reduce communications, costs, and privacy issues, etc.

A final concern with this approach is that it generally requires the use of baselines. The choice of a baseline can be contentious, if customers are given incentive payments by comparison of actual load to baseline load. Most predictive baseline models have significant error [113]. Moreover, baselines can be gamed by customers. However, there are a number of ways to get around these issues including contracting for the baseline in advance, also known as “build your own baseline” [114]. Additionally, when DR provides short timescale services the primary issue is high frequency differences in consumption and the baseline may not be necessary [111].

6.4.2 Provision of Adequate Control Signals

In the previous section, it was highlighted that a control signal can enable a reliable exploitation of DR resources. In the following an adaption of current control schemes in continental Europe is presented. Existing control structures are kept to show that the proposed form of demand side participation via contracts is implementable. In order to enable devices with limited energy capacity to participate in the current framework, it is necessary to do a refinement of the control structure. Therefore, the secondary control signal is decomposed into different components, with distinct ramping characteristics. The presented approach is not exhaustive in a sense that it presents a new market structure including new auction procedures. It gives also no recommendation about the optimal decomposition of the AGC signal. This is beyond the scope of this thesis.

Automatic Generation Control in Europe

Maintaining the frequency at its target value requires that the active power produced and consumed is controlled to keep the load and the
generation in balance. A certain amount of active power, called frequency control reserve, is kept available to perform this control. The TSO tenders the three above mentioned types of control (primary, secondary and tertiary) in specified quantities for its respective control area, both as positive (generation increase and load decrease) and negative (generation decrease and load increase) reserves. The amounts mainly depend on the size and generation portfolio of the control area [10].

The automatic control system consists of the primary control and the secondary control, while the tertiary control is activated manually in order to release the used primary and secondary control reserves after a disturbance. After the occurrence of a disturbance, the primary frequency control is activated in order to contain the frequency to an acceptable value. Subsequently, secondary frequency control is activated to restore the frequency to the nominal value and finally, tertiary frequency control in order to free the activated secondary reserves. In the secondary frequency control, which is also called Load Frequency Control, Automatic Generation Control (AGC) and (frequency) regulation, the power setpoints of the generators are adjusted in order to compensate for the remaining frequency error after the primary control has been activated. Apart from that, it counters the effect of the change in the load flows on the tie-lines to other areas that is caused by the active power imbalances and primary control actions. So the goals of AGC are the following [10]:

- Release primary control,
- Restore the frequency in the interconnected power system close to the nominal value,
- Restore the scheduled interchanges between different areas.

Secondary control reserves are activated by a PI-controller operated by the TSO. The AGC signal is transmitted by the TSO to the providing units in its control zone and it is dependent upon the Area Control Error (ACE), which should be controlled to zero. The power reference values of the generators participating in the AGC in an interconnected area will be adjusted accordingly.

The ACE in continental Europe is calculated according to [115]:

\[
ACE_i = P_{T_i} - P_{T0_i} + B(f - f_0),
\]  
(6.3)
where $P_{Ti}$ is the measured value of the total power exchange with the other control areas, $P_{T0i}$ is the scheduled power exchange with the other control areas, $B_i$ is the frequency bias factor of the controlled area, $f$ is the measured frequency and $f_0$ is the set value of the frequency. Fig. 6.5 shows a block diagram of the scheme.

**Decomposition of Automatic Generation Control for Demand Response**

Loads which are capable to provide demand response and distributed energy storages are potentially small and distributed and have storage constraints that have to be managed. In continental Europe, power imbalances that have to be covered by the automatic generation control at time $t$, can be calculated as:

$$ACE_{open\ loop}^t = -ACE^t + AGC^{t-1},$$

(6.4)

where $ACE_{open\ loop}^t$ is the area control error at time $t$ that would be observed if no automatic generation control is performed in the control area by the TSO. $ACE^t$ is the closed loop error at time $t$ observed by the system and $AGC^{t-1}$ is the already activated automatic generation control, thus the PI output at time $t - 1$. For providing possibilities for loads to participate in ancillary service markets, one possibility is a split of the AGC signal into slow and fast changing components, taking into account:
6.4. Direct Load Control and Contract-Based Rewarding

- Energy constraints,
- Ramping capabilities,
- Switching on/off cycles, in relation to the duty cycle that have to be fulfilled [116].

The ramping requirement is defined as the difference between two consecutive signal values. The number of changes of the signal direction within 1 hour is important especially for some types of loads managed by an aggregator, which have to respect a duty cycle e.g. 15 min, between switching on/off [116]. The bid-volume of the provider is limited when the signal changes the direction too often.

In order to split the signal in several components, real-time filtering with causal digital filters is applied [104]. The output of causal filters is only dependent upon past or present input data. The general setup is shown in Fig. 6.6. The AGC signal from the PI-controller is decomposed, where the filter can be either a Highpass/-or Lowpass-filter which results into an output (Signal A) which has either a high or low frequency component respectively. Signal B is the residual between the PI output and the filter output and contains the high frequency components in case of a Lowpass-filter, and the low frequency component in case of a Highpass-filter. A low frequency component corresponds to low ramping requirements, but a high energy content of the signal. Therefore it may be suited for conventional power generation with high inertia. A high frequency component corresponds to fast ramping requirements, but has low energy content. This means the fast devices with low energy capabilities, e.g. flywheels or batteries, are better suited to respond to this signal. This approach differs from the dynamics of the real-time security-constrained economic dispatch, because the dispatch decisions, even if scheduled with a short time interval, have discrete steps and values which do not vary within the scheduling period, whereas in this
Chapter 6. Incorporation of Demand Response

Proposal both slow and fast changing signals are part of the AGC and vary with its control cycle. The decomposition of the power imbalances handled by the AGC signal is accomplished using the Discrete Fourier Transform (DFT) [117]:

$$ACE_{\text{open loop}}^k = \sum_{t=0}^{N-1} ACE_{\text{open loop}}^t \cdot \exp^{-j\left(\frac{2\pi}{N}\right)t\cdot k}, k = 0, 1, \ldots, N - 1$$

(6.5)

where $x^t$ is the input sequence, N is the signal length, and $X^k$ is the output sequence of complex coefficients. By applying eq. (6.5) the dominant frequency components existing in the AGC signal are identified and can be used to establish proper system service products. Historical data for ACE and activated AGC with 10 seconds granularity are provided by the Swiss TSO for the months of July 2012 till January 2013. The Fast Fourier Transform (FFT) is applied on the averaged data for a whole day, and then on the average data of the 3-hour time slots 00-03, 06-09 and 21-24. The average imbalance is calculated out of the values of the same time step for every day of a month.

Table 6.1: Dominant frequency components resulting from the analysis of historic data.

<table>
<thead>
<tr>
<th>Frequency [Hz]</th>
<th>Period</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.00278</td>
<td>1 hour</td>
</tr>
<tr>
<td>0.000556</td>
<td>30 min</td>
</tr>
<tr>
<td>0.001111</td>
<td>15 min</td>
</tr>
<tr>
<td>0.001617</td>
<td>10 min</td>
</tr>
<tr>
<td>0.003333</td>
<td>5 min</td>
</tr>
<tr>
<td>0.01667</td>
<td>1 min</td>
</tr>
</tbody>
</table>

From Table 6.1 it can be seen that the predominant frequency corresponds to the 1 hour component, as a result of the hourly energy market operator, and also, cyclic components of 30 min, 15 min and less are observed. These can be attributed to ramping and fluctuations of load and generation [118].

For the design of the filter in Fig. 6.6, several types of causal filters can be assessed [104]. In [104], results for,

- Finite Impulse Response filters (FIR),
- Infinite Impulse Response filters (IIR),
• Exponential Weighted Moving Average filter (EWMA),

are presented. In this thesis, results for IIR and EWMA filters are presented. The general transfer function of an IIR is defined as [117]:

\[
H(z) = \frac{\sum_{n=0}^{P} b_n \cdot z^{-n}}{1 + \sum_{m=1}^{Q} a_m \cdot z^{-m}},
\] (6.6)

where \( b_n \) are the feedforward filter coefficients and \( a_m \) are the feedback filter coefficients, \( P \) is the feedforward and \( Q \) the feedback filter order, \( z^{-1} \) is a unit delay. IIR filters have both feedback and feedforward coefficients in eq. (6.6) and can be distinguished from the FIR-filters, where the denominator in eq. (6.6) is 1. On the one hand, the primary advantage of IIR filters over FIR filters is that they typically need much lower order for the same specifications. Apart from the filter type, the filter order is important since there is a trade off between the delay on the output and the fast frequency attenuation [119]. Simulations showed that FIR filters impose higher delay for the same frequency roll-off than the IIR due to their higher order [104]. On the other hand, IIR have a nonlinear phase, which means that the delay is a function of frequency (not a constant value as in the case of FIR Filters). In general a delay can cause problems when filters are used in real-time operation. The EWMA filter is a low-pass filter and is related to a 1st order IIR filter. The respective coefficients of the filters were determined in Matlab using predefined functions, a sampling rate of 10s and as the cutoff frequencies the dominant frequency components from Table 6.1. The order of the filters has been varied for test reasons.

Fig. 6.7 shows the average absolute ramping of the slow-changing signal generated by IIR filters, namely a 3rd order lowpass/highpass Chebyshev filter (CH\text{Low}/\text{High}), and the EWMA filters for cutoff frequencies of 1 hour, 30 min, 15 min, 10 min and 1 min as a function of the absolute energy content of the fast signal for the above filters and cutoff frequencies [104]. This form of representation is similar to [119]. It can be observed that the higher the delay of the filter due to its order and type, the more energy is required from the fast signal, because the time delay between the slow-changing signal and the initial one must be covered from the fast signal. The EWMA filter that has the lowest time delay (due to lower order) appears to have a moderate ramp-rate requirement for the slow signal and a low energy requirement for the units following the fast signal. Further, it can be observed that:
1. the lower the cutoff frequency, the lower the ramp-rate requirement of the slow signal, and

2. the lower the cutoff frequency, the higher the energy storage requirement of the fast signal.

Table 6.2 gives an overview of the signal’s changes in direction within one hour for each filter and cutoff frequencies, with 95% probability of not exceeding these values [103].

![Figure 6.7: Mean absolute ramping rate vs maximum energy for three filter types. The cutoff frequencies are the same for every filter and their values are marked in the diagrams for 1 h, 30 min, 15 min, 10 min, 5 min, 1 min, from left to right respectively](image)

Table 6.2: Upper limit of changes in direction with 95% probability of not exceeding these values

<table>
<thead>
<tr>
<th>Period</th>
<th>Lowpass</th>
<th>Highpass</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 h</td>
<td>4</td>
<td>60</td>
</tr>
<tr>
<td>30 min</td>
<td>5</td>
<td>72</td>
</tr>
<tr>
<td>15 min</td>
<td>10</td>
<td>87</td>
</tr>
<tr>
<td>10 min</td>
<td>15</td>
<td>96</td>
</tr>
<tr>
<td>5 min</td>
<td>27</td>
<td>111</td>
</tr>
<tr>
<td>1 min</td>
<td>106</td>
<td>162</td>
</tr>
</tbody>
</table>

Time domain simulations including the presented splits and an alternative method using optimization are presented in [103, 104].
6.5 Summary

Tables 6.3 and 6.4 summarize the main engineering and economic pros and cons associated with each DR program design example. The choice of a DR program design is a complex tradeoff between market efficiency, customer choice, and system reliability. As the tables show, there is an overlap between the engineering and economic arguments for and against each example; however, the terminology used is different. For example, both perspectives list decentralized decision making as a pro: For engineers, it means better modeling, control, and optimization. For economists, it means customers can make the decisions that they are better suited to make than any other entity. Additionally, price instability is a concern from both an economic and technical perspective, as are issues of complexity.

The appropriate choice of a DR program design depends on the objective, which is related to the timescale of the response. Both engineering and economic tools can be used to mitigate some of the disadvantages of the various designs, but certain set-ups have inherent limitations for certain applications. For example, consideration of timescales is especially important in power markets since the power system has very little storage capacity and many power system resources need significant time to respond to control signals. Reliable fast timescale response may require DLC since fast DR needs to be predictable and reliable, and to achieve that through markets would require high transaction costs. Price signals and markets are more suitable for slow DR, which usually supports economic objectives and is not critical for system reliability and security.

For a contract based rewarding with proper products and an efficient direct load control, a method of decomposing the existing control signals in Europe for frequency response has been presented. Dependent upon the tuning of the filter parameters, different desired combinations between ramping requirements and energy content of the control signal can be achieved. This allows the development of additional products for frequency response, which enable market participation of units with low energy capacity, but fast response time.
### Table 6.3: Engineering pros and cons for each example, Source: [102], p.8

<table>
<thead>
<tr>
<th></th>
<th>Engineering pros</th>
<th>Engineering cons</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Price Signals</strong></td>
<td>individual modeling, control, &amp; optimization</td>
<td>uncertain consumer behavior</td>
</tr>
<tr>
<td></td>
<td>no market bidding</td>
<td>possible instabilities</td>
</tr>
<tr>
<td></td>
<td>no baselines</td>
<td></td>
</tr>
<tr>
<td><strong>Price/Quantity</strong></td>
<td>predictable customer behavior</td>
<td>aggregate modeling, control &amp; optim-</td>
</tr>
<tr>
<td><strong>Bidding</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>controllability</td>
<td>baselines may be needed</td>
</tr>
<tr>
<td></td>
<td>aggregate market bidding</td>
<td></td>
</tr>
<tr>
<td><strong>Direct Load</strong></td>
<td>individual modeling, control, &amp; optimization</td>
<td>individual market bidding</td>
</tr>
<tr>
<td><strong>Control</strong></td>
<td>no baselines</td>
<td>market optimization via OPF non-</td>
</tr>
<tr>
<td></td>
<td></td>
<td>tractable</td>
</tr>
</tbody>
</table>

### Table 6.4: Economic pros and cons for each example, Source: [102], p.8

<table>
<thead>
<tr>
<th></th>
<th>Economic pros</th>
<th>Economic cons</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Price Signals</strong></td>
<td>customer optimize own consumption/investments</td>
<td>possible financial losses for customers</td>
</tr>
<tr>
<td></td>
<td>no privacy issues</td>
<td>uncertain consumer behavior</td>
</tr>
<tr>
<td></td>
<td></td>
<td>with fast-DR, high transaction costs with locational prices, fairness</td>
</tr>
<tr>
<td><strong>Price/Quantity</strong></td>
<td>low financial risk to consumer</td>
<td>true costs/benefits requires mechanism design</td>
</tr>
<tr>
<td><strong>Bidding</strong></td>
<td></td>
<td>privacy issues</td>
</tr>
<tr>
<td></td>
<td>low financial risk to BRP, ISO, TSO</td>
<td>requires self-enforcing contracts</td>
</tr>
<tr>
<td></td>
<td>easy to implement</td>
<td>no real-time customer choice</td>
</tr>
<tr>
<td><strong>Direct Load</strong></td>
<td>customer optimize own consumption/investments</td>
<td>incomplete markets must be addressed</td>
</tr>
<tr>
<td><strong>Control</strong></td>
<td>economically efficient</td>
<td>with fast-DR, high transaction costs with locational prices, fairness</td>
</tr>
</tbody>
</table>
Chapter 7

Design of Contract-Based Rewards

For a solitary animal egoism is a virtue that tends to preserve and improve the species: in any kind of community it becomes a destructive vice. Erwin Schrödinger

Chapter 6 highlighted the advantages of contract-based rewarding of direct load control for the provision of ancillary services. In this chapter, three different frameworks, which enable the design of contracts are presented. The main tasks of contract design is the consideration of the consumer welfare and the possibility that the consumer tries to act myopic and cheat on his capabilities in order to achieve higher rewards. Therefore contract design has to ensure that consumers are willing to reveal their true preferences. This chapter is based on [120] and [121].

7.1 Aggregation and the Role of Information

7.1.1 Introduction and Motivation

The incorporation of an aggregator as an intermediary in a market framework has so far not been investigated with regard to the amount of
information exchanged with the consumers. To the best of knowledge, in the context of contract design for DR, there does not exist a direct comparison, which evaluates the application of mechanism design and decentralized frameworks in terms of cost efficiency and the value of information exchange. The aggregator seeks to obtain as much private information as possible in a DR framework in order to operate efficiently. As highlighted in the previous chapter, the consumer’s desire is to keep as much information as possible private which may jeopardizes the goal of exploiting DR resources efficiently. A realistic market design for DR contracts has to strike a balance between these two conflicting objectives [16, 102, 106].

In the first section of this chapter, the impact of privacy considerations in several modeling frameworks for contract design in terms of economic performance of an aggregator and exploitation of existing demand resources is assessed. Three different methods to dispatch load for DR are investigated and compared:

- **Benchmark**: The cost effective demand response contracts are determined via a central optimization problem. The dispatching entity has full knowledge about the system, which helps to assess the value of information exchange and communication (see also Fig. 7.1a). In other words, the benchmark assumes that there exists no market friction in terms of information exchange between consumers and a central dispatch.

- **Central**: An aggregator determines cost effective demand response contracts by applying mechanism design. Mechanism design is a field which studies solution concepts for a class of games with private information [122]. Additionally the aggregator is participating non-cooperatively with the aggregated amount of reserve capacity provided by the consumers in a wholesale market platform (see also Fig. 7.1b).

- **Decentralized**: This approach has three steps: First, the consumers individually accept or reject a contract proposal provided by an aggregator, based on an explicit cost/benefit analysis. Second, consumers cooperatively pool their reserve power capacity via the aggregator, which acts as a mediator. Finally, the aggregator participates again with an aggregated amount of reserve capacity in a wholesale market platform (see also Fig. 7.1c). Therefore the
7.1. Aggregation and the Role of Information

![Diagram showing interaction of market participants]

(a) Benchmark: The centralized framework assumes full information exchange between the system operator and the consumer.
(b) Central: The centralized framework has an intermediate which aims to have as much information exchange as possible, whereas the consumer only reveals as much information as necessary.
(c) Decentralized: In a decentralized framework with cooperating agents, the aggregator acts as a mediator to facilitate a cooperative response from the consumers.

aggregator does not primarily manage loads but gathers information in a learning procedure, and acts as communication interface in order to enable cooperation among consumers.

7.1.2 Literature Review

Various approaches for a market-based DR participation in electricity markets have been proposed. As an example of a centralized framework, [53] proposes a complex bidding scheme for energy market participation of demand units. The bidding structure contains the private information.

Ref.[41] uses stochastic dynamic programming to value interruptable load contracts from a retailer’s perspective. Centralized incentive compatible contract design for local system services was proposed in [123, 124]. The authors apply mechanism design to ensure that customers reveal their true preferences about the costs of load curtailment. However, the central authority does not need to know details about the consumer’s costs of DR.
Decentralized approaches for demand side management are presented in [125, 126]. In [125] consumers communicate and engage in a non-cooperative game to adapt their individual energy schedule. The approach does not study the possible provision of system services. Applications of cooperative game theory to power systems were presented in [127, 128, 129, 130, 131]. Rather than focus on the rules of interaction like in non-cooperative approaches, cooperative game theory emphasizes the scope for mutual benefit [132]. The coalition formation process in this chapter is stylized with incentives supporting cooperation as well as factors which limit it. For example, one benefit of cooperation could be the higher robustness of pooled DR and therefore additional payment from an aggregator to the customers.

### 7.1.3 The Benchmark: Centralized Dispatch

The proposed contract design approaches are compared with a centralized dispatch problem. The aim of this problem is to minimize the procurement costs for ancillary services.

\[
\min_{\vartheta_1} J_1, \quad (7.1)
\]

where

\[
J_1 = \sum_{t=1}^{N_T} \left\{ \sum_{i=1}^{N_G} \left[ MC_{En} G_{En}^{i,t} + MC_{Resup,cap} G_{Resup,cap}^{i,t} \right] + MC_{Resdn,cap} G_{Resdn,cap}^{i,t} \right\} + \sum_{j=1}^{N_L} \left( C_{Stor}^{j,t} + C_{Resup}^{j,t} + C_{Resdn}^{j,t} \right),
\]

subject to

\[
\sum_{i=1}^{N_G} G_{En}^{i,t} - \sum_{j=1}^{N_L} D_{En}^{j,t} = 0, \forall t \quad (7.2)
\]

\[
\sum_{j=1}^{N_L} D_{Resup,cap}^{j,t} + \sum_{i=1}^{N_G} G_{Resup,cap}^{i,t} - R_{Req,Resup,cap}^t = 0, \forall t \quad (7.3)
\]

\[
\sum_{j=1}^{N_L} D_{Resdn,cap}^{j,t} + \sum_{i=1}^{N_G} G_{Resdn,cap}^{i,t} - R_{Req,Resdn,cap}^t = 0, \forall t \quad (7.4)
\]
7.1. Aggregation and the Role of Information

\[ D_{En}^{j,t} + D_{Resdn,cap}^{j,t} \leq \overline{D}^{j,t}, \forall j, t \]  
(7.5)

\[ D^{j,t} + D_{Resup,cap}^{j,t} \leq D_{En}^{j,t}, \forall j, t \]  
(7.6)

\[ G_{En}^{i,t} + G_{Resup,cap}^{i,t} \leq \overline{G}^{i,t}, \forall i, t \]  
(7.7)

\[ G^{i,t} + G_{Resdn,cap}^{i,t} \leq G_{En}^{i,t}, \forall i, t \]  
(7.8)

where \( \vartheta_1 \) is a vector of decision variables,

\[ \vartheta_1 = \{ G_{En}^{i,t}, G_{Resup,cap}^{i,t}, G_{Resdn,cap}^{i,t}, D_{Resup,cap}^{j,t}, D_{Resdn,cap}^{j,t} \}, \forall i, j, t, \]

which are all greater than or equal to zero, and defined as follows: \( G_{En}^{i,t} \) is the scheduled energy production of generator \( i \) at time \( t \), \( G_{Resup,cap}^{i,t} \) is its scheduled up-reserve capacity, and \( G_{Resdn,cap}^{i,t} \) is its scheduled down-reserve capacity, while \( D_{Resup,cap}^{j,t} \) is the scheduled up-reserve capacity of consumer \( j \) at time \( t \), and \( D_{Resdn,cap}^{j,t} \) is its scheduled down-reserve capacity.

Parameters \( N_G \), \( N_L \), \( N_B \) are the number of generators, loads, and buses, respectively; and \( N_T \) is the number of time steps. Parameters \( MC_{En}^{i,t} \), \( MC_{Resup,cap}^{i,t} \), and \( MC_{Resdn,cap}^{i,t} \) denote the cost of generator \( i \)'s energy production, up-reserves, and down-reserves, respectively, while \( C_{Stor}^{j,t} \), \( C_{Resup}^{j,t} \), and \( C_{Resdn}^{j,t} \) denote the cost of load \( j \)'s reserves, which are defined below. The objective function (7.1) minimizes the costs of procured energy and reserves.

Constraint (7.2) ensures power balance, where \( D_{En}^{j,t} \) is the forecasted electricity consumption of load \( j \) at time \( t \). Equations (7.3) and (7.4) ensure that the amount of up-reserves and down-reserves required by the system, \( R_{Req,Resup,cap}^{t} \) and \( R_{Req,Resdn,cap}^{t} \), are procured. Constraints (7.5)-(7.6) bound each load’s consumption, where \( \overline{D}^{j,t} \) and \( \underline{D}^{j,t} \) denote the maximum and minimum consumption of load \( j \).

Constraints (7.7)-(7.8) state the limits of generation. In the following, the method of modeling \( C_{Stor}^{j,t}, C_{Resup}^{j,t}, \) and \( C_{Resdn}^{j,t} \) is described. Energy shifting results in different costs than load shedding or load increases. Therefore the total DR capacity is divided into three components and the cost associated with each are computed. The energy shifting component of the reserve capacity of consumer \( j \) at time \( t \) is approximated as the symmetric reserve

\[ x^{j,t} = \min(D_{Resup,cap}^{j,t}, D_{Resdn,cap}^{j,t}), \]  
(7.9)
the loading shedding component of the reserve capacity as

\[ y^{j,t} = [D^{j,t}_{\text{Resdn,cap}} - D^{j,t}_{\text{Resup,cap}}]^+ , \]  

(7.10)

and the load increasing component of the reserve capacity as

\[ z^{j,t} = [D^{j,t}_{\text{Resup,cap}} - D^{j,t}_{\text{Resdn,cap}}]^+ , \]  

(7.11)

where \([\cdot]^+ = \max(\cdot, 0)\). Note that \(D^{j,t}_{\text{Resup,cap}} = x^{j,t} + z^{j,t}\) and \(D^{j,t}_{\text{Resdn,cap}} = x^{j,t} + y^{j,t}\).

The costs of shifting \(C_{\text{Stor}}^{j,t}\), shedding \(C_{\text{Resdn}}^{j,t}\), and increasing \(C_{\text{Resup}}^{j,t}\) are assumed to be quadratically increasing in quantity

\[
\begin{align*}
C_{\text{Stor}}^{j,t} &= a_{\text{Stor}}^{j,t} + b_{\text{Stor}}^{j,t} x^{j,t} + c_{\text{Stor}}^{j,t} (x^{j,t})^2, \\
C_{\text{Resup}}^{j,t} &= a_{\text{Resup}}^{j,t} + b_{\text{Resup}}^{j,t} y^{j,t} + c_{\text{Resup}}^{j,t} (y^{j,t})^2, \\
C_{\text{Resdn}}^{j,t} &= a_{\text{Resdn}}^{j,t} + b_{\text{Resdn}}^{j,t} z^{j,t} + c_{\text{Resdn}}^{j,t} (z^{j,t})^2, 
\end{align*}
\]

(7.12)\(\sim\) (7.14)

where \(a_{\text{Stor}}^{j,t}, b_{\text{Stor}}^{j,t}, \) and \(c_{\text{Stor}}^{j,t}\) are consumer \(j\)’s cost coefficients for providing energy shifting; \(a_{\text{Resup}}^{j,t}, b_{\text{Resup}}^{j,t}, \) and \(c_{\text{Resup}}^{j,t}\) are its cost coefficient for providing load shedding; and \(a_{\text{Resdn}}^{j,t}, b_{\text{Resdn}}^{j,t}, \) and \(c_{\text{Resdn}}^{j,t}\) are its cost coefficients for providing load increases.

7.1.4 Centralized Contract Design

A scenario in which an aggregator bids reserve capacity into the market is considered. The aggregator has contracts with individual consumers that each contribute to the total capacity; however, consumers do not share their full cost information with the aggregator [123]. Instead, the aggregator infers consumer costs by sending reserve prices to the consumers and observing their response, i.e., offered reserve capacity [124]. As a response to a price signal, each consumer determines its optimal up- and down-reserve capacity for each contract proposal by solving

\[
\max_{\vartheta_2} J_2^{j,t},
\]

(7.15)

where

\[ J_2^{j,t} = p^{j,t}_{\text{Resup,cap}} D^{j,t}_{\text{Resup,cap}} + p^{j,t}_{\text{Resdn,cap}} D^{j,t}_{\text{Resdn,cap}}, \]
subject to
\[ C_{Total}^{j,t} - p_{Resup,cap}^{j,t} D_{Resup,cap}^{j,t} - p_{Resdn,cap}^{j,t} D_{Resdn,cap}^{j,t} \leq 0, \] (7.16)
\[ C_{Total}^{j,t} = C_{Stor}^{j,t} + C_{Resup}^{j,t} + C_{Resdn}^{j,t} \] and
\[ \vartheta_2 = \{ D_{Resup,cap}^{j,t}, D_{Resdn,cap}^{j,t} \}. \] (7.18)

Constraint (7.16) ensures individual rationality. It is assumed that the aggregator develops a piece-wise constant cost/capacity estimates for each consumer. The quality of his estimate is a function of the curve resolution, i.e. number of steps where each step is generated from one price response.

Subsequent, a bilevel optimization problem, which connects the aggregator problem (leader-problem) with the system operator problem (follower-problem), is formulated. The aggregator aims to maximize profits by solving
\[ \max_{\vartheta_3} J_3, \] (7.19)
where
\[ J_3 = \sum_{t=1}^{N_T} \left\{ \sum_{j=1}^{N_L} \left( \lambda_{Resup,cap}^{t} D_{Resup,cap}^{j,t} + \lambda_{Resdn,cap}^{t} D_{Resdn,cap}^{j,t} \right. \right. \right. \]
\[ \left. \left. \left. - \kappa_{Resup,cap}^{j,t} - \kappa_{Resdn,cap}^{j,t} \right) \right\}, \]
subject to
\[ \kappa_{Resup,cap}^{j,t} - \tilde{C}_{Resup}^{j,t}(D_{Resup,cap}^{j,t}, D_{Resdn,cap}^{j,t}) \geq 0, \forall j, t \] (7.20)
\[ \kappa_{Resdn,cap}^{j,t} - \tilde{C}_{Resdn}^{j,t}(D_{Resup,cap}^{j,t}, D_{Resdn,cap}^{j,t}) \geq 0, \forall j, t \] (7.21)
\[ \kappa_{Resup,cap}^{j,t} - \tilde{C}_{Resup,cap}^{j,t}(D_{Resup,cap}^{j,t}, D_{Resdn,cap}^{j,t}) \geq \kappa_{Resup,cap}^{j',t}, \forall j, t \] (7.22)
\[ \kappa_{Resdn,cap}^{j,t} - \tilde{C}_{Resdn,cap}^{j,t}(D_{Resup,cap}^{j,t}, D_{Resdn,cap}^{j,t}) \geq \kappa_{Resdn,cap}^{j',t}, \forall j, t \] (7.23)
Chapter 7. Design of Contract-Based Rewards

Eqs. (7.5)-(7.6) and (7.9)-(7.11), where eqs. (7.22)-(7.23) are valid \( \forall j, j', t \). Variables \( \lambda^t_{\text{Resup,cap}} \) and \( \lambda^t_{\text{Resdn,cap}} \) denote prices for up- and down- reserve capacity at time \( t \) (determined through market clearing in the system operator’s problem); \( \tilde{C}^{j,t}_{\text{Resup,cap}} \) and \( \tilde{C}^{j,t}_{\text{Resdn,cap}} \) denote the aggregator’s estimate of the cost of consumer \( j \) for providing up- and down-reserve capacity; \( \kappa^{j,t}_{\text{Resup,cap}} \) and \( \kappa^{j,t}_{\text{Resdn,cap}} \) denote aggregator payments to consumer \( j \) for up- and down-reserves at time \( t \); \( j' \) indexes all consumers except consumer \( j \); and the decision vector is

\[
\vartheta_3 = \{ \kappa^{j,t}_{\text{Resup,cap}}, \kappa^{j,t}_{\text{Resdn,cap}}, \Lambda^t_{\text{Resup,cap}}, \Lambda^t_{\text{Resdn,cap}}, \}
\]

(7.24)

where \( \Lambda^t_{\text{Resup,cap}} \) and \( \Lambda^t_{\text{Resdn,cap}} \) are the aggregator’s up- and down-reserve capacity price bid curves. Constraints (7.20) – (7.21) ensure that each consumer profits from providing reserves, i.e. individual rationality, while constraints (7.22)-(7.23) ensure each consumer picks the best contract, i.e. incentive compatibility [133]. The decision variables \( D^{j,t}_{\text{Resup,cap}} \) and \( D^{j,t}_{\text{Resdn,cap}} \) \( \forall j, t \) belong to the feasible region defined by the system operator’s problem, which aims to minimize energy/reserve procurement costs,

\[
\min_{\vartheta_4} J_4,
\]

(7.25)

where

\[
J_4 = \sum_{t=1}^{N_T} \left\{ \sum_{i=1}^{N_G} \left( MC^{i,t}_{\text{En}} G^{i,t}_{\text{En}} + MC^{i,t}_{\text{Resup,cap}} G^{i,t}_{\text{Resup,cap}} \right. \right.
\]

\[
+ MC^{i,t}_{\text{Resdn,cap}} G^{i,t}_{\text{Resdn,cap}} \left. + \Pi^t_{\text{Resup,cap}} (\Lambda^t_{\text{Resup,cap}}, \Delta^t_{\text{Resup,cap}}) \right.
\]

\[
+ \Pi^t_{\text{Resdn,cap}} (\Lambda^t_{\text{Resdn,cap}}, \Delta^t_{\text{Resdn,cap}}) \left. \right\},
\]

subject to (7.2) – (7.4) and (7.7) – (7.8), where \( \Pi^t_{\text{Resup}} \) and \( \Pi^t_{\text{Resdn}} \) are the costs of the up- and down-reserve capacity \( \Delta^t_{\text{Resup}} \) and \( \Delta^t_{\text{Resdn}} \) provided by the aggregator at \( t \) and

\[
\vartheta_4 = \{ G^{i,t}_{\text{En}}, G^{i,t}_{\text{Resup,cap}}, G^{i,t}_{\text{Resdn,cap}}, \Delta^t_{\text{Resup,cap}}, \Delta^t_{\text{Resdn,cap}} \} \forall i, t.
\]

Note that the choice of \( \Delta^t_{\text{Resup,cap}} \) and \( \Delta^t_{\text{Resdn,cap}} \) determines \( \lambda^t_{\text{Resup,cap}} \) and \( \lambda^t_{\text{Resdn,cap}} \).
To solve this problem, it is assumed that

\[ \Pi_{t}^{\text{Resup,cap}} = \sum_{j=1}^{N_L} \Lambda_{\text{Resup,cap}}^{j,t} D_{\text{Resup,cap}}^{j,t} \]

and

\[ \Pi_{t}^{\text{Resdn,cap}} = \sum_{j=1}^{N_L} \Lambda_{\text{Resdn,cap}}^{j,t} D_{\text{Resdn,cap}}^{j,t}, \]

where \( \Lambda_{\text{Resup,cap}}^{j,t} \) and \( \Lambda_{\text{Resdn,cap}}^{j,t} \) are the aggregator’s price bids for selling consumer \( j \)’s up- and down-reserve capacity at time \( t \). Therefore, the aggregator acts as a middleman who passes on the bids of each consumer. The Karush Kuhn Tucker (KKT) conditions of the (convex) lower level problem into the upper-level problem, which results in a mathematical program with equilibrium constraints (MPEC) [21, 134] and described in appendix B.4.1.

### 7.1.5 Decentralized Contract Design

In this approach consumers individually optimize their reserve capacity offers against contract proposal offers from the aggregator. As in the previous approach, the aggregator bids reserve capacity into the market and has contracts with individual consumers that each contribute to the total capacity; however, here the contracting process is different. Specifically, the aggregator provides a set of contract proposals to the consumers and each chooses the one that suits it best, or rejects them all, and sends its contract choice and optimal reserve capacity offer to the aggregator, which is in this approach an information hub. Then, using the consumers’ responses, the aggregator chooses the best coalition of consumers and bids the reserves into the market. The second step leads to the application of cooperative game theory (see also appendix B.4.2). Over time, the aggregator optimizes the contract parameters through learning.

The following example, adapted from ref. [135], motivates the choice of a cooperative framework. Assume \( N \) homogenous individuals enter a contract to provide reserves. The level of reserves is \( Q \). Further, it is assumed that an individual’s \( j \) benefit of \( Q \) is [135]:

\[ B_{j}(Q) = \frac{b(aQ - \frac{Q^2}{2})}{N}, \quad (7.26) \]
where $a > 0$ and $b > 0$. The cost to an individual to contribute an amount $q_j$ of reserves is:

$$C_j(q_j) = \frac{cq_j^2}{2},$$

(7.27)

where $c > 0$. The optimal amount of system service $Q^*$ is determined by maximizing the global net benefit

$$\Pi = \sum_{j \in NL} \pi_j,$$

(7.28)

where $\pi_j = B_j(Q) - C_j(q_j)$ is the individual’s net benefit. In the case of full cooperative behavior between the agents, the optimal amount of service provision is

$$Q^*_c = \frac{aN_L}{N_L + \frac{c}{b}},$$

(7.29)

and

$$q^*_c = \frac{a}{N_L + \frac{c}{b}}.$$

(7.30)

In case of non-cooperative behavior (maximizing the individual’s net benefit) the amount decreases to [136]:

$$Q^*_o = \frac{a}{1 + \frac{c}{b}}.$$

(7.31)

Since $Q^*_c \geq Q^*_o$, the cooperative approach results in more operating reserves provided.

In practice consumers may act cooperatively, because it increases their negotiation power. Additionally, since reserves enhance power system reliability, they may be seen as public goods, and consumers may find it beneficial to cooperatively contribute to the production of a public good [137]. Since the aggregator acts only as a mediator in a cooperative setting, the rent that is created through the bidding process on the wholesale market can be entirely distributed among the consumers in a coalition.

For modeling purposes it is assumed that first a consumer is either part of the coalition or not. Second, a coalition does not create positive or negative spillovers to consumers who are not part of the coalition. Therefore there is no need to evaluate combinations of coalitions [138]. Third, there exists an optimal mechanism that determines the allocation
7.1. Aggregation and the Role of Information

of the coalition’s benefit to each consumer [139, 140]. A full solution to a cooperative game is a payoff division vector that splits the value of a coalition such that (a) it is efficient (i.e., the sum of the payoff vector must be equal the value of the coalition), (b) any subset of coalition members has at least as much payoff by joining the coalition as by participating alone and has no incentive to leave the coalition, and (c) any subset of non-coalition members has no incentive to join [141]. The last two items ensure incentive compatibility of the coalition and individual rationality, and define the set of stable coalitions.

In the following, the consumer’s optimization problem, the coalition formation process, the wholesale dispatch problem, and the method of contract parameter optimization are described.

**Consumer’s optimization problem**

The aggregator provides a set of contract proposals \( K^t \) for up- and down-reserve capacity a time \( t \). Every contract proposal \( k^{k,t} \in K^t \) is a vector

\[
k^{k,t} = \{ p^{k,t}_{\text{Resup,cap}}, p^{k,t}_{\text{Resdn,cap}}, D^{k,t}_{\text{Resup,cap}}, D^{k,t}_{\text{Resdn,cap}} \},
\]

where \( k \) is the contract proposal index; \( p^{k,t}_{\text{Resup}} \) and \( p^{k,t}_{\text{Resdn}} \) are the price per unit of up- and down-reserve capacity; and \( D^{k,t}_{\text{Resup}} \) and \( D^{k,t}_{\text{Resdn}} \) are the minimum up- and down-reserve capacity required at time \( t \) under contract proposal \( k \).

At each time, each consumer determines its optimal up- and down-reserve capacity for each contract proposal by solving

\[
\max_{\vartheta^{j,k,t}} J^{j,k,t}_5,
\]

where

\[
J^{j,k,t}_5 = p^{k,t}_{\text{Resup,cap}} D^{j,k,t}_{\text{Resup,cap}} + p^{k,t}_{\text{Resdn,cap}} D^{j,k,t}_{\text{Resdn,cap}},
\]

subject to

\[
D^{k,t}_{\text{Resup,cap}} - D^{j,k,t}_{\text{Resup,cap}} \leq 0,
\]

\[
D^{k,t}_{\text{Resdn,cap}} - D^{j,k,t}_{\text{Resdn,cap}} \leq 0,
\]

\[
C^{j,k,t}_{\text{Total}} - p^{k,t}_{\text{Resup,cap}} D^{j,k,t}_{\text{Resup,cap}} - p^{k,t}_{\text{Resdn,cap}} D^{j,k,t}_{\text{Resdn,cap}} \leq 0,
\]

(7.5) – (7.6) and (7.9) – (7.14),
Chapter 7. Design of Contract-Based Rewards

where $C_{\text{Total}}^{j,k,t} = C_{\text{Stor}}^{j,k,t} + C_{\text{Resup}}^{j,k,t} + C_{\text{Resdn}}^{j,k,t}$ and

$$
\vartheta_{5}^{j,k,t} = \{D_{\text{Resup,cap}}^{j,k,t}, D_{\text{Resdn,cap}}^{j,k,t}\}.
$$

Constraints (7.34)–(7.35) ensure that the minimum reserve capacity requirements are met and (7.36) ensures individual rationality. At each time $t$, each consumer chooses the contract proposal that results in the highest revenue. Let $k_{*}^{j,t}$ be consumer $j$’s optimal contract at time $t$, $p_{\text{Resup,cap}}^{j,t}$ and $p_{\text{Resdn,cap}}^{j,t}$ be the payments associated with $k_{*}^{j,t}$, and $D_{\text{Resup,cap}}^{*j,t}$ and $D_{\text{Resdn,cap}}^{*j,t}$ be the optimal reserve capacity under contract $k_{*}^{j,t}$. The consumer communicates $k_{*}^{j,t}$, $D_{\text{Resup,cap}}^{*j,t}$, and $D_{\text{Resdn,cap}}^{*j,t}$ to the aggregator. If a consumer finds no feasible solutions to (7.33), he/she rejects all contracts and cannot participate in a coalition.

**Coalition formation**

At each time $t$, two coalitions form – one for up-reserve capacity and one for down-reserve capacity. For simplicity, only the process for up-reserve capacity is described. The aggregator aims to maximize the value of up-reserve capacity by solving

$$
\max_{\phi_{\text{Resup,cap}}^{t}} J_{5}^{t} = B_{C}^{t}(\phi_{\text{Resup,cap}}^{t}) - C_{C}^{t}(\phi_{\text{Resup,cap}}^{t}),
$$

(7.37)

where $\phi_{\text{Resup,cap}}^{t}$ is the list of the indices of consumers within a coalition, $B_{C}^{t}$ is the benefit of a coalition, and $C_{C}^{t}$ is the cost of a coalition in time $t$. If the objective value is negative, then no coalition is formed. If the objective value is positive, the optimal coalition is denoted $\phi_{\text{Resup,cap}}^{*t}$. We assume the benefits of cooperation at time $t$ are

$$
B_{C}^{t}(\phi_{\text{Resup,cap}}^{t}) = \sum_{j \in \phi_{\text{Resup,cap}}^{t}} p_{\text{Resup,cap}}^{j,t} D_{\text{Resup,cap}}^{j,t} + Inc_{t}^{t},
$$

(7.38)

where $Inc_{t}^{t}$ is an additional benefit that results from cooperative behavior, such as those described above. The design of this benefit term determines in case of costly coalition formation the payoff for the individual, and hence, the incentives for individuals to form a coalition. Further, these incentive payments have to be shared efficiently among consumers. If $Inc > 0$ and there are no costs of coalition formation, then the game is superadditive and the optimal coalition structure includes all agents; however, with costs, this is not usually the case. Costs
of coalition formation could include physical limits, costs of coordination overhead like communication systems, and/or anti-trust penalties [142, 140]. For simplicity, it is assumed that these costs are related to the size of a coalition

\[
C^t_C(\phi^t_{Resup,cap}) = a^t_C + b^t_C|\phi^t_{Resup,cap}| + c^t_C(|\phi^t_{Resup,cap}|)^2, \tag{7.39}
\]

where \(a^t_C, b^t_C, \) and \(c^t_C\) are cost parameters.

**Wholesale dispatch problem**

The wholesale dispatch problem is equivalent to (7.25); however, the aggregator’s up- and down-reserve capacity price bid curves, \(MC_{Resup,cap}\) and \(MC_{Resdn,cap}\), are now a function of the capabilities/costs of only the consumers within the optimal coalition. To solve this problem, price/quantity bids are set as,

\[
\Pi^t_{Resup,cap} = \sum_{j \in \phi^*_{Resup,cap}} \Lambda^j_{Resup,cap} D^*_{Resup,cap},
\]

and

\[
\Pi^t_{Resdn,cap} = \sum_{j \in \phi^*_{Resdn,cap}} \Lambda^j_{Resdn,cap} D^*_{Resdn,cap}.
\]

Note that the price bids must be greater than or equal to the optimal price, i.e. \(\Lambda^j_{Resup} \geq p^*_{Resup}\) and \(\Lambda^j_{Resdn} \geq p^*_{Resdn}\). Since the aggregator itself is in this framework ideally a not-for-profit entity they are set equal. The aggregator’s price bidding curves are piece-wise constant functions resulting in a mixed integer linear program.

**Optimization of Contract Parameters**

The payments of the aggregator to the consumer are related to the minimum reserve requirements via linear functions:

\[
p^k_{Resup} = \alpha^t_{Resup,cap} + \beta^t_{Resup,cap}D^k_{Resup}, \tag{7.40}
\]

\[
p^k_{Resdn} = \alpha^t_{Resdn,cap} + \beta^t_{Resdn,cap}D^k_{Resdn}, \tag{7.41}
\]

where \(\alpha^t_{Resup,cap}\) and \(\alpha^t_{Resdn,cap}\) are the intercepts and \(\beta^t_{Resup,cap}\) and \(\beta^t_{Resdn,cap}\) are the slopes of the up- and down-reserve capacity contract.
offer curves at time \( t \). Other relations between payment and minimum reserve requirements are possible but are not investigated in this thesis. The intercepts and slopes in (7.40) – (7.41) are optimized via Q-learning. The Q-value is a mapping of a specific action to a reward. The reward is the payment from the system operator to the aggregator minus remuneration of the consumers for providing reserve capacity. The Q-value is updated iteratively with [143]. The action is a choice of a factor that the intercept/slope are multiplied by and which can vary within a fixed interval (see also appendix B.4.3).

7.1.6 Simulation Setup

Seven consumers with different physical potential to provide DR capacity are considered. Further, these are classified dependent upon the costs of DR provision in three types. Two consumers of Type I, three consumers of Type II and two consumers of Type III. The specific economic and physical data are given in the appendix A.4. The potential for providing up and down reserves capacity is limited to 20\% of the energy demand of every type. In order to assess the performance of the proposed approaches in terms of exploitation of existing DR resources and cost efficiency, we investigate several approaches:

1. CB: Centralized approach as stated in section 7.1.3,
2. CIC: Centralized approach as stated in section 7.1.4,
3. CNIC: Centralized approach as stated in section 7.1.4 but ignoring the incentive compatibility constraints (7.22)-(7.23) for the consumers. Thus, the aggregator’s problem reduces to a cost-efficient procurement and selling of DR capacity.
4. DNC: Decentralized approach as stated in section 7.1.5 without any cost of coalition formation, \( \mathcal{C}_C^0 = 0 \).
5. DC: Decentralized approach as stated in section 7.1.5 with costs that hinder grand coalition formation, as defined below.

The time step is one hour and the optimization horizon is 24 hours. In the decentralized approaches DNC and DC, the size of the contract set (i.e. \(|\mathcal{K}|\)) that the consumer can choose from is varied. Numerical values for \( D_{\text{Resup/dn,cap}}^{k,t} \) are given in the appendix. For a higher robustness
of the results, the learning procedure of the aggregator is repeated 10 times. Every learning sequence consists of $N_R = 200$ iterations. The factor to optimize the intercept and slope in eqs. (7.40) and (7.41) can be set between $[0, 3]$. The initial values are $\alpha_{t_{\text{Resup/dn,cap}}} = 3$ and $\beta_{t_{\text{Resup/dn,cap}}} = 6$ for all $t$. The parameters of the cost function of cooperation $C_1$ are given with $a_t = 20$, $b_t = 40$, and $c_t = 20$ for all $t$. They are chosen such that a comparable outcome to the centralized incentive compatible approach CIC is possible in terms of resource exploitation. The benefits of coalition formation where assumed to be a linear function of the amount of reserve capacity in a coalition where the factor was 0.005.

7.1.7 Results

Exploitation of Demand Resources and Aggregator’s Reward

The exploitation of demand resources is defined as the portion of the load dispatched in the benchmark approach. The reward for the aggregator is defined as income from the wholesale auction minus payments to the consumer for providing DR. Results are averaged over the optimization horizon of 24 hours. Fig. 7.2 shows the share of the considered load types in providing up reserve capacity in the benchmark case. The benchmark approach performs best since it provides in nearly every hour full coverage of reserve needs by demand resources. Table 7.1 shows the average exploitation of demand resources and the average reward for the aggregator.

All approaches nearly exploit the full demand response potential. However, as seen in the payments to the consumer in Fig. 7.4, this is done not nearly as cost efficient as in the benchmark. In the case of costly coalition formation consumers do not find it worth aggregating to a large coalition, i.e. due to high communication costs or insufficient additional benefits of cooperation. Further, preference revelation constraints, as applied in CIC, reduce the reward of the aggregator which shows the trade-off between efficiency and incentive compatibility in market designs with limited information exchange. The reduction depends upon the setting of the cost functions.

With regards to the approach DNC the decoupling of the optimization procedure of the aggregator and the consumer leads to a lower profit since the aggregator eventually collects more DR capacity than it can
Table 7.1: Average hourly exploitation of DR reserve capacity (as percent of exploitation in the benchmark approach CB) and aggregator reward (as percent of total reserve costs in the benchmark approach CB).

<table>
<thead>
<tr>
<th></th>
<th>CIC&lt;sup&gt;a&lt;/sup&gt;</th>
<th>CNIC&lt;sup&gt;a&lt;/sup&gt;</th>
<th>DNC&lt;sup&gt;b&lt;/sup&gt;</th>
<th>DC&lt;sup&gt;b&lt;/sup&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>Exploitation</td>
<td>99.8%</td>
<td>99.8%</td>
<td>91.1%</td>
<td>86.1%</td>
</tr>
<tr>
<td>Reward</td>
<td>188.0</td>
<td>266.8</td>
<td>9.0</td>
<td>7.6</td>
</tr>
</tbody>
</table>

<sup>a</sup> 128 steps in the cost curves

<sup>b</sup> 4 contract proposals for up/down reserve capacity

sell on the wholesale market. Thus, it is found that dependent upon the design of the set of contracts it may cannot achieve enough profits to cover the costs of procurement. An improvement in terms of rewards could be achieved through a non-linear relationship between the payments and the minimum required amount of DR in the learning sequence.

In case of cost of cooperation, DC, the reward for the aggregator is lower since it has to make higher payments to get the same quantity of DR capacity exploited from the consumer. In case of too low payments, the consumers wouldn’t cooperate. In case of high costs of cooperation, this means that the aggregator is making losses. The results change with the assumed cost factors, the amount of considered time periods per contract, and the amount of contracts. However, an arbitrary high amount
of contract proposals does not necessarily improve market efficiency and in practise will probably even decrease it due to high transaction costs.

**Effect of Limited Information in Centralized Design**

The efficiency of the approaches CIC and CNIC is strongly determined by the accuracy of the available cost functions. Fig. 7.3 shows the exploitation of DR resources compared with the benchmark and the reward in terms of costs of DR in the benchmark approach dependent upon a change in the number of steps from initially 128 steps to 4 steps. It is observed that the amount of DR exploitation and along with it the reward from the aggregator decrease significantly with a change from 128-32 steps, where at 32 steps around only 20% of DR are exploited compared to the benchmark. The number of steps may also correlate to the effort of the aggregator to extract as accurate information from the consumer as possible. Hence, a high number of price steps leads to high transactions costs in practise and may hinder markets to work properly. Vice versa, a rough differentiation in terms of price response also hinders reasonable DR resource exploitation.

Fig. 7.4 shows the payments to consumers in the CIC and CNIC scenarios as a function of the number of steps in the consumer cost curve approximation. Again, more steps generally leads to better results, i.e., higher payments for the consumers. Note that the rewards are significantly larger than payments because the profit-maximizing aggregator is able to leverage the price differential between generator and DR reserve costs. We find that the even though the exploitation is identical, payments in the CIC scenario are significantly higher than those in the CNIC scenario for our parametrization. Thus, the incentive compatibility constraints in the CIC scenario enforce a payment differentiation between the consumers, which results in a lower efficiency of the CIC scenario, specifically, the same resources are exploited at a higher price.

**Effect of Costs & Contract Set Sizes in Decentralized Design**

Table 7.1 showed that the potential for DR resource exploitation and hence the reward of the aggregator decreases in case of costly coalition formation. Fig. 7.5 shows the decline in DR resource exploitation in case of rising costs from $C_1$, $C_2 = 2 \times C_1$ and $C_3 = 3 \times C_1$. Results are shown
Figure 7.3: Exploitation and reward of the aggregator in comparison with the benchmark exploitation and the costs of total reserves in the benchmark approach. Exploitation and reward with incentive compatibility constraints, $E_I$ and $R_I$. In case of no incentive compatibility constraints the exploitation and rewards are practically the same.

Figure 7.4: Payments when no incentive compatibility constraints are enforced, no IC, and when they are enforced, IC. In case of incentive compatibility constraints, the payments are generally higher. In case of a high resolution of the cost curve the difference between the payments is highest.

for the cases with strategic behavior of the aggregator and without. Fig. 7.6 shows the change of the aggregator’s reward as a function of the coalition formation costs. With learning, the aggregator aims to keep the amount of DR exploitation low in order to maximize its reward. However, due to costs of coalition formation the reward goes back. In
case of no-learning procedure, the aggregator gains in case of costs of coalition formation. The aggregator doesn’t change its payments to the consumer, but due to the costly coalition formation process and therefore DR available in the wholesale auction, the arbitrage rises. This increase in wholesale prices overcompensates the reduction of sold DR capacity.

![Figure 7.5: Demand resource exploitation compared with the benchmark approach](image)

Figure 7.5: Demand resource exploitation compared with the benchmark approach dependent upon the cost of coalition formation where \( C_2 = 2 \times C_1 \), \( C_3 = 3 \times C_1 \). Exploitation is shown in case of the set of contracts consists of 2-4 contracts. Thus, in case of maximization of aggregator reward, \(|\mathcal{K}| = 4\), \(|\mathcal{K}| = 9\) and \(|\mathcal{K}| = 16\). In case of no optimization of the contract parameters, \(NL\) shows the average exploitation rate over all contract set sizes if no maximization of the aggregator reward takes place.

Fig. 7.7 shows the average exploitation of DR and the reward in terms of the total worth of reserves in the benchmark approach over all cost cases, dependent upon the number of contracts. The maximization of the aggregator reward leads in this setting to a lower exploitation rate in terms of DR. However, as seen in Fig. 7.7, the reward in case of strategic behavior is on average significantly higher than the reward without strategic behavior. If the aggregation of consumers is the marginal supplier of reserve capacity on the wholesale market, prices drop in this setting and the margin between buying cheap reserve capacity from the consumer and selling it to wholesale prices diminish. In other words, as soon as abundant DR is a price maker, and DR is cheaper than conventional generation the aggregation units loose income and hence their business case in the long run. In the short-run, price volatility due to rational and reward maximizing behavior of several entities is possible.
Figure 7.6: Reward compared with the benchmark approach dependent upon the cost of coalition formation where $C_2 = 2 \times C_1$, $C_3 = 3 \times C_1$. The reward is shown in case of the set of contracts consists of 2-4 contracts. Thus, in case of maximization of aggregator reward, $|K| = 4$, $|K| = 9$ and $|K| = 16$. In case of no optimization of the contract parameters, $NL$ shows the average reward over all possible contract sizes if no maximization of the aggregator reward takes place.

Figure 7.7: Resource exploitation with/without contract parameter optimization, $E_{as/ns}$, as percent of the benchmark exploitation, and the reward of the aggregator with/without contract parameter optimization, $R_{as/ns}$, as ratio of the costs of reserves in the benchmark, dependent upon the number of contracts provided by the aggregator. The comparison takes the average over all considered cases of costs of coalition formation.

Finally, the number of contracts shows decreasing returns in terms of DR exploitation, especially in the case of low costs of cooperation.
7.1. Aggregation and the Role of Information

7.1.8 Summary

This section presented a comparison of different frameworks which aim to reward demand response based on contracts. The scope was on demand response for ancillary services. It has been shown that a crucial issue in terms of exploitation of existing DR resources and cost efficiency is the treatment of information and hence privacy. Two new approaches were presented to assess these issues and were compared to a benchmark approach with full information access.

The contributions of this section are as follows:

1. A novel incentive compatible centralized contract design approach with endogenous valuation of the procured DR by an aggregator is provided. Information exchange between the aggregator and the consumer is based on mechanism design (Fig. 7.1b).

2. A novel approach to design DR contracts based on a decentralized approach by using cooperative game theory, an aggregator as intermediary, and limited required information exchange between the aggregator and the consumer (Fig. 7.1c) is introduced.

3. A comparison between the approaches with regards to the impact of costly information exchange on the cost efficiency of the aggregator and the exploitation of demand resources is done. The benchmark approach assumes complete and truthful information exchange and is therefore most cost efficient.

Incentive compatibility constraints leads to a reduction of resource exploitation and rewards for the aggregator. Further, the success of third-party contract design in terms of the exploitation of DR resources shows a high sensitivity on the resolution of the DR cost curves consumer and therefore well informed aggregators. On the other hand, an approach based on cooperative game theory shows high sensitivity on the costs of decentralization and the reward of the aggregation is exposed to high uncertainty if the costs are close to the benefits of decentralization. However, the decentralized approach was presented in a stylized version and shows the problematic between finding a trade-off between the exploitation and the information exchange. Ideally, the benchmark approach and the centralized approach with incentive compatibility constraints act as upper and lower bound in terms of acceptable costs for cooperative DR exploitation.
Chapter 7. Design of Contract-Based Rewards

7.2 Non-Linear Contract Design

7.2.1 Motivation

In the bilevel optimization problem (7.19)-(7.25) from section 7.1, the traded product dealt with is reserve capacity. The aim was to establish a rewarding framework with contracts, which enables truthful preference revelation. The considered cost functions for the consumer had to be estimated by the aggregator. However, the cost functions for reserve provision in eqs. (7.9)-(7.14) were approximations with regard to storage constraints. In this chapter, the complexity of the contracting framework is increased by assuming rewards for reserved capacity and deployed energy supply considering explicitly limited storage capabilities of the consumer. Thus, the financial reward and hence the success of DR programs is in this section determined by (a) the capacity and energy constraints of consumers providing DR, and (b) the flexibility of the contract framework considering storage capabilities of the loads, the resolution of the estimated cost curves, and the time horizon of the contract.

Similar to section 7.1.4, a contract design framework for third-party contracting, which involves incentive compatibility constraints, is applied. Incentive compatibility means that the consumer reveals his true costs of DR. However, the approach is augmented with principles of non-linear pricing as explained in appendix B.3.1. Non-linear contracts incorporate two separate payments, where a fixed payment deals with the remuneration of capacity costs and a usage payment with the cost of expected deployed energy.

Therefore the lower-level dispatch problem includes price bids from the aggregator and the generators in order to cope with certain reserve capacity and energy requirements. It can be argued that the formulation is more complete in terms of passing benefits of DR to the consumer. It maps the general setup of today’s wholesale markets for ancillary services, since it rewards capacity reservation and deployed energy separately. The model is assessed in terms of efficiency with a benchmark approach, which assumes full truthful preference revelation and no aggregator.

As highlighted in the previous section, the aggregator seeks to collect as much private information as possible and the consumer has the intention to keep as much information as possible private. The severity
of this problem will increase even more when additional information about the state of charge of a consumer is necessary in order to design efficient contracts. In this chapter it is assumed that the aggregator applied a screening procedure to estimate the necessary parameters of the consumers.

### 7.2.2 Modeling

It is assumed that the aggregator has estimates about the necessary physical and economic parameters of the consumer types. The objective of the upper level problem is defined as a profit maximization problem of the aggregator with payments for DR capacity and deployed energy to consumer \( j \). Capacity and energy may be optimized on different time schedules \( t \) and \( \tau \). Further, different scenarios \( s \) for the deployment of AS energy are assumed:

\[
\max_{\phi_1} \sum_{j=1}^{N_L} \left( \sum_{t=1}^{N_T} \left( \lambda_{\text{Resup,cap}}^t D_{\text{Resup,cap}}^{j,t} + \lambda_{\text{Resdn,cap}}^t D_{\text{Resdn,cap}}^{j,t} - \kappa_{\text{Resup,cap}}^{j,t} - \kappa_{\text{Resdn,cap}}^{j,t} \right) + \sum_{s=1}^{N_S} \omega_s \left\{ \sum_{j=1}^{N_L} \left( \lambda_{\text{Resup,en}}^{\tau,s} D_{\text{Resup,en}}^{j,\tau,s} - \kappa_{\text{Resup,en}}^{j,\tau,s} - \kappa_{\text{Resdn,en}}^{j,\tau,s} \right) \right\} \right),
\]

subject to eqs. (7.43)-(7.58). Variables \( \lambda_{\text{Resup/dn,cap}}^t \) and \( \lambda_{\text{Resup/dn,en}}^{\tau,s} \) are the prices from the wholesale auction for capacity and energy. \( \kappa_{\text{Resup/dn,cap}}^{j,t} \) and \( \kappa_{\text{Resup/dn,en}}^{j,\tau,s} \) are the payments from the aggregator to consumer for provision of AS capacity or energy, \( D_{\text{Resup/dn,cap}}^{j,t} \) and \( D_{\text{Resup/dn,en}}^{j,\tau,s} \). Parameter \( \omega_s \) is the weighting of the respective scenarios. Equation (7.43) ensures the individual rationality of the aggregator:

\[
\sum_{t=1}^{N_T} \sum_{j=1}^{N_L} \left( \lambda_{\text{Resup,cap}}^t D_{\text{Resup,cap}}^{j,t} + \lambda_{\text{Resdn,cap}}^t D_{\text{Resdn,cap}}^{j,t} - \kappa_{\text{Resup,cap}}^{j,t} \right) + \sum_{\tau=1}^{N_{\tau}} \left( \lambda_{\text{Resup,en}}^{\tau,s} D_{\text{Resup,en}}^{j,\tau,s} - \kappa_{\text{Resup,en}}^{j,\tau,s} - \kappa_{\text{Resdn,en}}^{j,\tau,s} \right) \geq 0, \forall s
\]
Chapter 7. Design of Contract-Based Rewards

For clarity, only the costs for up reserves are stated in eqs. (7.44)-(7.58). Constraint (7.44) ensures the individual rationality of the consumer with cost functions defined in (7.45) and (7.48):

\[
\sum_{t=1}^{N_T} (\kappa_{j,t}^{\text{Resup,cap}} - \tilde{C}_{j,t}^{\text{Resup,cap}}) + \sum_{\tau=1}^{N_{\tau}} (\kappa_{j,\tau,s}^{\text{Resup,en}} - \tilde{C}_{j,\tau,s}^{\text{Resup,en}}) \geq 0, \forall j, \forall s
\]

(7.44)

where \( \tilde{C}_{j,t}^{\text{Resup,cap}} \) and \( \tilde{C}_{j,\tau,s}^{\text{Resup,en}} \) are the costs of reserve capacity reservation and reserve energy deployment. The marginal cost function for the costs of DR capacity provision, \( \tilde{MC}_{j,t}^{\text{Resup,cap}} \), is defined as:

\[
\tilde{MC}_{j,t}^{\text{Resup,cap}} = \tilde{a}_{j,t}^{\text{Resup,cap}} + \tilde{b}_{j,t}^{\text{Resup,cap}} D_{j,t}^{\text{Resup,cap}} + \tilde{c}_{j,t}^{\text{Resup,cap}} D_{j,t}^{\text{Resup,cap}}^2
\]

(7.45)

where \( \tilde{a}_{j,t}^{\text{Resup,cap}} > 0, \tilde{b}_{j,t}^{\text{Resup,cap}} > 0, \) and \( \tilde{c}_{j,t}^{\text{Resup,cap}} > 0 \) is assumed. Eq. (7.45) is stepwise approximated with \( N_{Qu} \) steps for reserve capacity [49]. Eq. (7.46) determines the cost of reserve capacity provision over all cost segments, and (7.47) the quantity of reserve capacity provided in sum over all segments:

\[
\sum_{qu=1}^{N_{Qu}} \tilde{MC}_{j,t,qu}^{\text{Resup,cap}} D_{j,t,qu}^{\text{Resup,cap}} = \tilde{C}_{j,t}^{\text{Resup,cap}}, \forall j, t
\]

(7.46)

\[
\sum_{qu=1}^{N_{Qu}} D_{j,t,qu}^{\text{Resup,cap}} - D_{j,t}^{\text{Resup,cap}} = 0, \forall j, t
\]

(7.47)

where \( D_{j,t,qu}^{\text{Resup,cap}} \) is the \( qu^{th} \) segment of the cost curve for reserve capacity provision. The costs of demand for providing AS capacity, \( \tilde{C}_{j,t}^{\text{Resup,cap}} \), may comprise lost opportunity costs due to missing flexibility in energy market operation or a monetary threshold below which demand units are not willing to participate in the ASM at all. The costs for demand for providing balancing energy, \( \tilde{C}_{j,t}^{\text{Resup,en}} \), are dependent upon the exploitation of the physical storage. Equations (7.48)-(7.53) attribute to every e’th charging level marginal costs \( \tilde{MC}_{j,\tau,e,s}^{\text{Resup,en}} \) for balancing energy provision:

\[
\tilde{C}_{j,\tau,s}^{\text{Resup,en}} = \sum_{e=1}^{N_E} \tilde{MC}_{j,\tau,e,s}^{\text{Resup,en}} (D_{\text{Resup,en}}^{j,\tau,e,s} - D_{\text{Resup,en}}^{j,\tau,e,s}^*) , \forall j, \tau, s
\]

(7.48)
where $D_{\text{Resup, en}}^{j, \tau, e, s}$ is an auxiliary variable to determine the right cost segment for the provision of reserve energy.

\[
0 \leq D_{\text{Resup, en}}^{j, \tau, e, s} - D_{\text{Resup, en}}^{j, \tau, e, s} \leq u_E^{j, \tau, e, s} M_E, \forall j, \tau, e, s
\] (7.49)

\[
0 \leq D_{\text{Resup, en}}^{j, \tau, e, s} \leq (1 - u_E^{j, \tau, e, s}) M_E, \forall j, \tau, e, s
\] (7.50)

\[
\sum_{e=1}^{N_E} u_E^{j, t, e, s} = 1, \forall j, \tau, s
\] (7.51)

\[
E^{j, \tau, s} \geq \sum_{e \in N_E} E_{\text{seg}}^{j, \tau, e} u_E^{j, \tau, e, s}, \forall j, t, s, e = [1, \ldots, N_E - 1]
\] (7.52)

\[
E^{j, \tau, s} \leq \sum_{e \in N_E} E_{\text{seg}}^{j, \tau, e+1} u_E^{j, \tau, e+1, s}, \forall j, t, s, e = [2, \ldots, N_E]
\] (7.53)

where $E^{j, \tau, s}$ is the storage charging level of consumer $j$ at time $\tau$ in scenario $s$. $E_{\text{seg}}^{j, \tau, e}$ is the predefined $e$th segment of the storage. In specific, eqs. (7.48)-(7.51) handle the problem of having a multiplication between a continuous and a binary decision variable when choosing segment-wise cost curves for energy provision [144]. Storage operation is modeled via eqs. (7.54)-(7.57):

\[
E^{j, \tau+1, s} = E^{j, \tau, s} + \mu_{\text{ch}}^{j, \tau} D_{\text{Resdn, en}}^{j, \tau, s} + \mu_{\text{disch}}^{j, \tau} D_{\text{Resup, en}}^{j, \tau, s}, \forall j, s
\] (7.54)

\[
E^{j, 1, s} = E^j, \forall j, s
\] (7.55)

\[
E^{j, N_E, s} = E^f, \forall j, s
\] (7.56)

\[
0 \leq E^{j, \tau, s} \leq \overline{E}^{j, \tau}, \forall j, \tau, s
\] (7.57)

where $E^j$ is the initial storage charging level, $E^f$ is the final charging level at the end of the optimization horizon, and $\overline{E}^{j, \tau}$ is the maximal charging level. The costs of storage operation with respect to a certain charging level are normalized. In case of deviations from this charging level, as shown in Fig. 7.8, the provision of balancing energy comes with different cost dependent upon the direction. For example, in case of a nearly empty storage, it may be more costly to provide upward reserve energy than downward balancing energy, which charges the storage. Note that eq. (7.54) states that the sum of accepted contracts influences
Figure 7.8: Schematic illustration of the costs of storage utilization of consumer $j$ in case of deployment of balancing energy, $D^j_{Resup, en}$ and $D^j_{Resdn, en}$, dependent on the charging level of the storage. The costs of provision of consumer $j$, $C^j_{Resup/Resdn, en}$, rise with the distance from the reference point $E^j_{norm}$ and are highest near the physical bounds of the storage. We discretize the available storage capacity in $N_E$ steps. We assume $E^j_{norm}$ to be 50% of the maximal charging level $E^j_{max}$.

the storage content of the consumer. Constraint (7.58) ensures incentive compatibility of the contract proposals of the aggregators for up-reserve contracts. The individual payment that consumer $j$ receives from the aggregator must be such that he doesn’t misrepresent his preferences to be like the ones from $j'$, where $j'$ refers to all other consumers:

$$\sum_{t=1}^{N_T} \left( \kappa^j_{Resup, cap} - \tilde{C}^j_{Resup, cap} \right) + \sum_{\tau=1}^{N_\tau} \left( \kappa^j_{Resup, en} - \tilde{C}^j_{Resup, en} \right) \geq \sum_{t=1}^{N_T} \left( \kappa^{j', t'}_{Resup, cap} - \tilde{C}^{j', t'}_{Resup, cap} \right) + \sum_{\tau=1}^{N_\tau} \left( \kappa^{j', \tau', s}_{Resup, en} - \tilde{C}^{j', \tau', s}_{Resup, en} \right), \forall j, s$$

(7.58)

where eq. (7.58) is similar for down reserve contracts. Variable $\vartheta_1$ is a vector of decision variables which comprises of

$$\vartheta_1 = \{ D^j_{Resup, cap}, D^j_{Resdn, cap}, D^j_{Resup, en}, D^j_{Resdn, en}, E^j_{\tau, s}, u^j_{\tau, e, s}, u^j_{Resup/Resdn} \}, \forall j, t, \tau, s.$$

The decision variables $D^j_{Resup, cap}$, $D^j_{Resdn, cap}$, $D^j_{Resup, en}$, and $D^j_{Resdn, en}$ lie in the feasible set of the lower level problem which is defined as a dispatch problem of the system operator. The lower level problem includes the price bids from the aggregators and the generators in order to cope with certain reserve capacity and energy requirements. The aim to minimize procurement costs of reserve capacity and balancing
7.2. Non-Linear Contract Design

energy:

\[
\min_{\vartheta_2} \sum_{t=1}^{N_T} \sum_{i=1}^{N_G} (MC_{\text{Resup, cap}}^{i,t} G_{\text{Resup, cap}}^{i,t} + MC_{\text{Resdn, cap}}^{i,t} G_{\text{Resdn, cap}}^{i,t}) \\
+ \sum_{b=1}^{N_B} \left( \alpha_{\text{Resup, cap}}^{b,t} D_{\text{Resup, cap}}^{b,t} + \beta_{\text{Resdn, cap}}^{b,t} D_{\text{Resdn, cap}}^{b,t} \right) \\
+ \sum_{s=1}^{N_S} \omega_s \left\{ \sum_{\tau=1}^{N_T} \left( MC_{\text{Resup, en}}^{i,\tau} G_{\text{Resup, en}}^{i,\tau,s} + MC_{\text{Resdn, en}}^{i,\tau} G_{\text{Resdn, en}}^{i,\tau,s} \right) \\
+ \sum_{b=1}^{N_B} (\gamma_{\text{Resup, en}}^{b,\tau,s} D_{\text{Resup, en}}^{b,\tau,s} + \delta_{\text{Resdn, en}}^{b,\tau,s} D_{\text{Resdn, en}}^{b,\tau,s}) \right\},
\]

(7.59)

where \( \alpha_{\text{Resup, cap}}^{b,t}, \beta_{\text{Resdn, cap}}^{b,t}, \gamma_{\text{Resup, en}}^{b,\tau,s}, \text{ and } \delta_{\text{Resdn, en}}^{b,\tau,s} \) are the \( b \)-th segment of price bids of the aggregator for up/down reserve capacity and deployed energy. As highlighted in section 7.1.4, these price bids are based on the procurement of DR from the consumer. Objective (7.59) is subject to constraints (7.60)-(7.70). Eqs. (7.60)-(7.62) state the balance for reserve capacity and up/down balancing energy respectively:

\[
R_{t, \text{Req, Resup/dn, cap}}^t = \sum_{i=1}^{N_G} G_{\text{Resup/dn, cap}}^{i,t} - \sum_{b=1}^{N_B} D_{\text{Resup/dn, cap}}^{b,t}, \forall t
\]

(7.60)

\[
R_{\tau,s, \text{Req, Resup, en}} = \sum_{i=1}^{N_G} G_{\text{Resup, en}}^{i,\tau,s} + \sum_{j=1}^{N_B} D_{\text{Resup, en}}^{b,\tau,s}, \forall \tau, s
\]

(7.61)

\[
R_{\tau,s, \text{Req, Resdn, en}} = -\sum_{i=1}^{N_G} G_{\text{Resdn, en}}^{i,\tau,s} - \sum_{j=1}^{N_B} D_{\text{Resdn, en}}^{b,\tau,s}, \forall \tau, s
\]

(7.62)

\[
G_{\text{Resup, en}}^{i,\tau,s} = \max(0, v_G^{i,\tau,s}), \forall i, \tau, s
\]

(7.63)

\[
G_{\text{Resdn, en}}^{i,\tau,s} = \max(0, -v_G^{i,\tau,s}), \forall i, \tau, s
\]

(7.64)

\[
-\frac{N_T}{N_T} G_{\text{Resdn, cap}}^{i,t} \leq v_G^{i,\tau,s} \leq \frac{N_T}{N_T} G_{\text{Resup, cap}}^{i,t}, \forall i, \tau \in t, s
\]

(7.65)
where \( v_G \) and \( v_D \) are auxiliary variables in order to distinguish between up and down deployed energy. Eqs. (7.63)-(7.68) ensure that either up or down balancing energy are supplied by generator \( i \) or consumer type \( j \) in time instant \( \tau \) respectively (also in every scenario \( s \) for deployed energy). Eqs. (7.69)-(7.70) ensure that the capacity limits of the generator are fulfilled:

\[
0 \leq G_{i,t}^{\text{Resup/dn,cap}} \leq \bar{G}_{i,t}^{\text{Resup/dn,cap}}, \forall i, t \tag{7.69}
\]

\[
0 \leq D_{b,t}^{\text{Resup/dn,cap}} \leq \bar{D}_{b,t}^{\text{Resup/dn,cap}}, \forall b, t \tag{7.70}
\]

Variable \( \vartheta_2 \) is a vector of decision variables which comprises

\[
\vartheta_2 = \{G_{i,t}^{\text{Resup,cap}}, G_{i,t}^{\text{Resdn,cap}}, D_{b,t}^{\text{Resup,cap}}, D_{b,t}^{\text{Resdn,cap}}, G_{i,\tau,s}^{\text{Resup,en}}, G_{i,\tau,s}^{\text{Resdn,en}}, D_{b,\tau,s}^{\text{Resup,en}}, D_{b,\tau,s}^{\text{Resdn,en}}, v_G^{i,\tau,s}, v_D^{b,\tau,s}\}, \forall i, b, t, \tau, s.
\]

All decision variables are greater or equal to zero. We assume that the number of price/volume blocks \( b \) of aggregator \( a \) are equal to the number of different payments to the consumer types. However, in real operation the aggregator has most likely a different bidding in the wholesale market compared to his retail level activity. The stated problem formulation (7.42)-(7.70) can be solved by expressing the lower level problem (7.59)-(7.70) as KKT - conditions and including it in the upper level optimization problem (7.42)-(7.58) [21, 134].

### 7.2.3 Simulation Setup

Data from the test system from section 7.1 and appendix A.4 are assumed. The size of the problem is reduced to three consumers, where each consumer has a different cost structure, similar to the cost types in the previous section. Different to the previous approach, no traded energy is assumed. However, the approach could be extended in that direction. AS capacity and energy is contracted on a hourly basis. The
time horizon is 24 hours. In this simulation no grid constraints are considered, but the model can be extended in this direction.

Similar to section 7.1 the presented approach is compared with a benchmark approach, which is a central dispatch problem that considers costs of deployed energy, and no incentive compatibility constraints. The objective of the benchmark is the minimization of procurement costs of AS capacity and balancing energy.

Economic data of the loads are given in the appendix in Tables A.23 and A.22. The costs of providing up reserve capacity per load type in Table A.22 have to be multiplied with the normalized elements of Table A.21 respectively. Cost of providing down reserve capacity per load type have to be multiplied with the inverse of the normalized elements respectively. The maximal physical capabilities for DR are 20% of the demand in Table A.21. The requirements for reserve capacity are 10 times the requirements according to the ENTSO-E formula [31]. The energy requirements per time instant $\tau$ is drawn from a normal distribution function:

$$R_{\text{Req,Resup/dn,en}}^{\tau,s} \sim \mathcal{N}(0, \frac{1}{15}) * R_{\text{Req,Resup/dn,cap}}^{\tau}, \tau \in t, \forall s. \quad (7.71)$$

Two different energy deployment scenarios were considered. A higher number of simulation scenarios leads to a significant increase of binary decision variables and slows down simulation time. Due to it’s combinatorial structure, the problem could not be decomposed into smaller sub-problems. Simulations are repeated five times for higher robustness of the results. The exploitation of demand resources is defined as the portion of the load dispatched in the benchmark approach. Results are averaged over the optimization horizon of 24 hours. The storage parameters $E_I$, $E_F$, $E^j$, $E^j$ are multiplied with a factor $0.25 \times n_S$, where $n_S$ is a control variable which influences the size of the storage. The bigger $n_S$, the larger the storage. The number of cost segments stays constant. Storage is divided in four segments, the cost curve for capacity provision in eight segments. The costs of storage and capacity are varied separately. The values of the cost segments for capacity are multiplied with a factor $0.5 \times n_C$ where $n_C$ is a control variable. The values of the cost segments for energy are multiplied with a factor $0.5 \times n_E$ where $n_E$ is a control variable. The benchmark approach considers $n_C = 1$ and $n_E = 1$. The approach was implemented in Matlab using the interface YALMIP and IBM ILOG CPLEX as solver [55],[56], and [145].
7.2.4 Results

Impact of Storage Capability

Fig. 7.9 and 7.10 show the exploitation of reserve capacity and energy dependent upon the costs of reserve capacity. The number of deployment scenarios is three. The effect of an increase of costs of energy provision is ambiguous, which is due to the fact that the costs of deployed energy are still lower in case of DR compared to generators. It can be observed that the reserve capacity procured and sold by the aggregator is diminishing with rising costs. Further, the overall exploitation of capacity is significantly lower than in the benchmark case. This is in contrast to the approach presented in section 6.1, and can be explained by the consideration of time-coupled constraints and the connection of incentive-based payments over several time periods. The exploitation of the energy potential is high. However, the energy potential exploitation decreases with the amount of reserved capacity.

Fig. 7.11 shows the ratio between payments of the aggregator for reserve capacity to the consumer and the total wealth of reserves. It can be seen that the payments go down with rising costs of reserve capacity provision since otherwise the aggregator would make losses. This is due to the setup of the rationality constraints in the optimization problem, which do not differ if the income stems from reserve capacity provision, or energy deployment.

![Graph showing the exploitation of reserve capacity potential](image)

Figure 7.9: Exploitation of reserve capacity potential for the case of rising costs of capacity $n_C$ and the size of the storage $n_S$. The storage capacity and the costs of deployed energy have only a small influence on the exploitation of capacity potential.
7.2. Non-Linear Contract Design

Figure 7.10: Exploitation of the energy potential for the case of rising costs of capacity $n_C$ and the size of the storage $n_S$. The storage capacity has an influence on the exploitation of capacity potential, which indicates the optimal size of the storage given an statistically known set of uncertainty and an competitive environment.

Figure 7.11: Ratio between payments for reserve capacity and the value of reserve capacity in the benchmark approach. Rising costs lead to a reduction of the payments in a competitive environment.

Impact of Contract Duration

Fig. 7.12 shows the exploitation of energy potential in case of an increase of the payment period, $T$. This means that the payments are
constant for several hours. The costs of storage and capacity are varied separately. In this simulation an average over all cost scenarios for energy is taken.

Fig. 7.12 and 7.13 show that an increase of the payment period from 1 hour, to a duration of 8 hours leads to a reduction of the exploitation of DR capacity, and to a reduction of the payments for capacity compared with the benchmark approach. A further increase to 12h payment period leads to reduction of the exploitation below 30% compared with the benchmark. However, the reduction relative to the case of 12h is less. Similar results could be observed for energy in Fig. 7.14 and 7.15, which leads to the conclusion that a reasonable response from the demand side may require a more dynamic setting of ancillary service markets with shorter intervals of auctions. However, the benefits of a shorter rolling horizon setup of auctions for ancillary services for demand units have to be assessed with regard to the total system costs which involves also conventional generation [146].

![Figure 7.12: Exploitation of reserve capacity compared with the benchmark approach.](image)

$T = 1$, $T = 8$, and $T = 12$ refer to payment durations of 1h, 8h, and 12h respectively.
7.2. Non-Linear Contract Design

Figure 7.13: Ratio of payments for capacity from the aggregator to the consumer and the total value of reserves (capacity+energy) from the benchmark approach. A higher payment period reduces significantly the payments and hence the potential to extract DR energy.

Figure 7.14: Exploitation of reserve energy compared with the benchmark approach. $T = 1$, $T = 8$, and $T = 12$ refer to payment durations of 1h, 8h, and 12h respectively.
7.2.5 Summary

In this section, a framework for non-linear contract design to reward the provision of demand response for ancillary services was presented. An aggregator was modelled as an intermediate between wholesale energy market operation and retail markets. The aggregator has to provide incentive compatible contracts, which ensure the sufficient rewarding of reserve capacity and balancing energy due to energy storage limitation on the consumer side.

Several design parameters of the contract have been assessed. Simulation results show that a high time resolution for contracts is beneficial in terms of DR exploitation, and the availability of accurate information increases cost efficiency in DR exploitation for capacity and deployed energy. For clarity reasons no grid and no explicit modelling of market operation for traded energy was incorporated. However, the model can be extended in this direction.

Generally, it has to be noted that large scale combinatorial problems are hard to solve. Therefore, a trade-off between the cost-curve resolution, the number of scenarios, the number of market participants, and the resolution of the energy deployment settlement has to be considered.
Chapter 8

Closure Part II

Those among us who are unwilling to expose their ideas to the hazard of refutation do not take part in the scientific game. Karl R. Popper, The Logic of Scientific Discovery

This chapter concludes the second part of the thesis by summarizing the work, drawing conclusions and suggesting open issues for future work

8.1 Summary

In the second part of the thesis a market framework for demand side participation was proposed based on a contract-based rewarding. Subsequently, pre-defined system services can be called up by the system operator via direct load control. Different to real-time pricing and direct bidding, these form of demand side participation may enable the most reliable access to power system flexibility on the demand side. Several methods to determine cost-efficient contracts have been investigated. One of the key issues is incentive compatibility, that means consumers reveal their true costs/preferences about demand response services. Further, the investigation assessed the role of a third party-entity, an aggregator, and the specific problem of limited storage capabilities of demand units.
8.2 Conclusion

Simulation results and the assessment of different market setups have disclosed several issues. General results are that:

- Market designs for demand response for ancillary services have to consider that consumer and intermediate market entities like aggregators may have conflicting objectives. Consumers only want to share as much information as needed, which may significantly reduce the success of demand response programs in terms of resource exploitation.

- Pricing concepts have to consider that the commodity electricity should be defined of several characteristics: The speed of response, the power output and the energy capacity of the signal, which requires complex pricing schemes.

From a modeling perspective:

- Multi-part pricing schemes and contract design assessment in a bilevel optimization setup are combinatorial problems, which are hard to apply in large scale applications. The theoretic validity of a preference revelation mechanism has to be assessed in models in order avoid too low or high incentive-based payments.

- Decentralized setups based on cooperative game theory show similar results through reasonable approximations. Further, they can circumvent the problem of dimensionality through solving simpler problems. However, further refinements of the approach in terms of payoff allocation also introduce additional steps in the market procedure, which may increase complexity again.

8.3 Outlook

The second part of the thesis provides several starting points for future research. A chapter-wise overview of further aspects with regards to the applied methods, the numerical assessment, and the practical implementation is presented below. This list is not exhaustive but highlights immediate points of open research:
• **Chapter 6**: The proposal of several differentiated market products requires proper wholesale auction design. In particular the trade-off between more complete markets through a variety of products and the problem of diminishing liquidity in the auction process is a point of future research.

• **Chapter 7**: The large scale implementation of combinatorial problems as in the case of bilevel optimization requires further research. Further, a computationally efficient improvement of the robustness of the approach with regards to uncertainty.

The decentralized approach has been shown in a stylized version and therefore offers several fields of improvement such as in the coalition formation procedure, the extension for multiple coalition formation (second best solutions), and the improvement of incentive mechanisms to participate in an aggregated system.

Both approaches may also consider grid infrastructure on distribution level. However, generalizable statements require well-designed test-cases.
Part III

Appendices and Bibliography
Appendices
Appendix A

A.1 Data and Test System Chapter 2

Tables A.1-A.5 contain relevant system data used for the simulations. $E$ represents the segment bounds. $MC_{En}$ is equal to $MC_{Resup}$ and $MC_{Resdn}$. The costs of reserves power provision are valid for event-based and non event-based reserves.

Table A.1: Technical data of generators

<table>
<thead>
<tr>
<th>G</th>
<th>$G^{s\text{Rup,Rdn}}$</th>
<th>$t_{\text{Up/Dn}}$</th>
<th>$t_{\text{Init}}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>G_1</td>
<td>150</td>
<td>65/15/75</td>
<td>4/4/4</td>
</tr>
<tr>
<td>G_2</td>
<td>120</td>
<td>70/70/80</td>
<td>2/3/-3</td>
</tr>
<tr>
<td>G_3</td>
<td>80</td>
<td>100/100/100</td>
<td>1/1/-1</td>
</tr>
</tbody>
</table>

Table A.2: Economic data of generators

<table>
<thead>
<tr>
<th>G</th>
<th>$C_{\text{Start}}$</th>
<th>$C_{\text{noLoad}}$</th>
<th>$MC_{En}$</th>
<th>$E_{G}^{0,1,2}$</th>
<th>$C_{\text{Rup/Rdn}}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>G_1</td>
<td>500</td>
<td>550.15</td>
<td>39.5/40.02/40.55</td>
<td>0/50/100</td>
<td>100/100</td>
</tr>
<tr>
<td>G_2</td>
<td>250</td>
<td>310.97</td>
<td>63.0/64.2/65.4</td>
<td>0/50/75</td>
<td>100/100</td>
</tr>
<tr>
<td>G_3</td>
<td>150</td>
<td>10.97</td>
<td>73.0/77/78</td>
<td>0/40/65</td>
<td>100/100</td>
</tr>
</tbody>
</table>

Table A.3: Energy demand of the loads $D_{En}^{L}$

<table>
<thead>
<tr>
<th>$L_1$</th>
<th>$L_2$</th>
<th>$L_3$</th>
</tr>
</thead>
<tbody>
<tr>
<td>[MW]</td>
<td>[MW]</td>
<td>[MW]</td>
</tr>
<tr>
<td>90 * $s^t$</td>
<td>95 * $s^t$</td>
<td>85 * $s^t$</td>
</tr>
</tbody>
</table>
Appendix A.

Table A.4: Abatement cost for reserves and ramping effort

<table>
<thead>
<tr>
<th>$F_{noevt,j,t}^{Resup/dn,ab}$</th>
<th>$F_{j,t}^{Rup/dn,ab}$</th>
<th>$\eta_{noevt,j,t}^{Resup/dn,ab}$</th>
<th>$\eta_{j,t}^{Rup/dn,ab}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>$L_{1,2,3}$</td>
<td>2</td>
<td>0.65</td>
<td>0.65</td>
</tr>
</tbody>
</table>

The benefits curves for event-based reserves are assumed to be $F_{Resup/dn}^{evt,j,t} = 2.5D_{En}^j$ and $\eta_{Resup/dn}^{evt,j,t} = -0.65$ for all loads.

Table A.5: Time series of loads

<table>
<thead>
<tr>
<th>$s^t$</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
</tr>
</thead>
<tbody>
<tr>
<td>$t$</td>
<td>9</td>
<td>10</td>
<td>11</td>
<td>12</td>
<td>13</td>
<td>14</td>
<td>15</td>
<td>16</td>
</tr>
</tbody>
</table>

Table A.6: Line data

<table>
<thead>
<tr>
<th>Line</th>
<th>1-4</th>
<th>4-5</th>
<th>5-6</th>
<th>3-6</th>
<th>6-7</th>
<th>7-8</th>
<th>8-2</th>
<th>8-9</th>
<th>9-4</th>
</tr>
</thead>
<tbody>
<tr>
<td>$r$  [p.u.]</td>
<td>0</td>
<td>0.017</td>
<td>0.039</td>
<td>0</td>
<td>0.0119</td>
<td>0.0085</td>
<td>0</td>
<td>0.032</td>
<td>0.01</td>
</tr>
<tr>
<td>$x$  [p.u.]</td>
<td>0.0576</td>
<td>0.092</td>
<td>0.17</td>
<td>0.0586</td>
<td>0.1008</td>
<td>0.072</td>
<td>0.0625</td>
<td>0.161</td>
<td>0.085</td>
</tr>
<tr>
<td>Rate [MW]</td>
<td>250</td>
<td>250</td>
<td>150</td>
<td>300</td>
<td>150</td>
<td>250</td>
<td>250</td>
<td>250</td>
<td>250</td>
</tr>
</tbody>
</table>

A.2 Data and Test System Chapter 3

Load data for energy demand are taken from [76]. The wind farm starts with investments of 1000 m.u. for local flexibility. Wind sites are located either at bus 3 or 24.

Table A.7: Abatement cost for reserves loads (L), and wind sites (W)

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The costs of reserve energy provision are assumed to be the same as the costs for traded energy in case of up-reserves. In case of down reserves the marginal costs of reserve energy provision are assumed to be zero.
### Table A.8: Generation data chapter 3

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### Table A.9: Generation data chapter 3, marginal costs are valid for reserve capacity

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Table A.10: Generation data chapter 3 continued, marginal costs are valid for reserve capacity

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A.3 Data and Test System Chapter 4

Tables A.14-A.16 contain system data used for the simulations. Time series data for the load $s^t$ are following chapter 2.

The technical data for generators are the same as in Table A.1.

The economic data with regards to the preferences of the BRPs for non event-based reserve capacity are given in Table A.16.

The line data are the same as in Table A.6. Further, in simulation scenarios with congestion the line capacity of line 4–5 reduces to 60MW, and of line 7 – 8 to 100MW.

A.4 Data and Test System Chapter 6

Tables A.17-A.21 contain relevant system data used for the simulations in section 6.1.

Tables A.22-A.23 contain relevant system data used for the simulations in section 7.2. Generation data are similar to Table A.17. Time series of load dependent upon consumer type is similar to Table A.21. For
the cost parameters $\tilde{a}_{\text{Resup/dn,cap}}$, $\tilde{b}_{\text{Resup/dn,cap}}$, $\tilde{c}_{\text{Resup/dn,cap}}$ two steps are done: First, the data in A.21 are normalized by $(4.97, 7.455, 10.5)$ for the respective load types. Second, the cost parameters $\tilde{a}'_{\text{Resup/dn,cap}}$, $\tilde{b}'_{\text{Resup/dn,cap}}$, $\tilde{c}'_{\text{Resup/dn,cap}}$, stated in Table A.23, are multiplied with the inverse of this normalized data in case of up-reserves and with the normalized data for down-reserves. Thereby, a time dependency for the costs of reserves is created.

The costs of the storage segments increase quadratically with the segments between minimal and maximal storage capacity times 15.
Table A.12: Generation data chapter 3 continued

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### Table A.13: Line data chapter 3

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### Table A.14: Technical data generators in chapter 4

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<th>$G$</th>
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<th>Start-Up</th>
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<tr>
<td>[MW]</td>
<td>[MW]</td>
<td>[h]</td>
<td>[m.u.]</td>
</tr>
<tr>
<td>$G_1$</td>
<td>150</td>
<td>0</td>
<td>1</td>
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<tr>
<td>$G_2$</td>
<td>120</td>
<td>0</td>
<td>1</td>
</tr>
<tr>
<td>$G_3$</td>
<td>80</td>
<td>0</td>
<td>1</td>
</tr>
</tbody>
</table>
Table A.15: Economic data generators chapter 4

| G_1 | 39.49/40.02/45.55 |
| G_2 | 53.01/54.24/59.41 |
| G_3 | 63.01/64.24/68.41 |

Table A.16: Economic data of balance responsible parties: Willingness to pay for AS capacity, Energy Demand, Parameters for demand for balance energy

<table>
<thead>
<tr>
<th>(a/b/c)_Resup_cap</th>
<th>D^j_En</th>
<th>η^j_Resup/dn/F^j_Resup/dn</th>
</tr>
</thead>
<tbody>
<tr>
<td>BRP 1 1900/140/1.8</td>
<td>90</td>
<td>-1.0 / (2s^j D^j_En)</td>
</tr>
<tr>
<td>BRP 2 1500/115/1.4</td>
<td>95</td>
<td>-1.2 / (2s^j D^j_En)</td>
</tr>
<tr>
<td>BRP 3 900/70/0.9</td>
<td>85</td>
<td>-1.4 / (2s^j D^j_En)</td>
</tr>
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</table>

Table A.17: Economic and technical data of generators in chapter 6. Values are constant over all time instances t

<table>
<thead>
<tr>
<th>M_{C_{En}}^{i,t}</th>
<th>M_{C_{Resup}}^{i,t}</th>
<th>M_{C_{Resdn}}^{i,t}</th>
<th>G^i</th>
<th>G_{Rup/Rdn}^i</th>
</tr>
</thead>
<tbody>
<tr>
<td>G_1 45.02</td>
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<td>40.49</td>
<td>160</td>
<td>60/60</td>
</tr>
<tr>
<td>G_2 54.24</td>
<td>57.41</td>
<td>51.01</td>
<td>120</td>
<td>60/60</td>
</tr>
<tr>
<td>G_3 57.24</td>
<td>60.41</td>
<td>55.01</td>
<td>80</td>
<td>80/80</td>
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</tbody>
</table>

Table A.18: Cost factors of different load types providing DR and maximal physical amounts. Values stay constant for all time instances t.

<table>
<thead>
<tr>
<th>a_j,t</th>
<th>b_j,t</th>
<th>c_j,t</th>
<th>D^{j,t}/D^{j,t}</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>0.1/0.15/0.15</td>
<td>3/65/65</td>
<td>0.2/1.9/1.9</td>
</tr>
<tr>
<td>II</td>
<td>0.2/0.25/0.3</td>
<td>4/70/70</td>
<td>0.3/2.85/2.85</td>
</tr>
<tr>
<td>III</td>
<td>0.3/0.3/0.4</td>
<td>5/75/75</td>
<td>0.9/8.55/8.55</td>
</tr>
</tbody>
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Table A.19: Parameter of the learning sequence of the aggregator

<table>
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<tr>
<th>N_R</th>
<th>Markup [%]</th>
<th>γ</th>
<th>α_{Resup/Resdn}</th>
<th>β_{Resup/dn}</th>
</tr>
</thead>
<tbody>
<tr>
<td>200</td>
<td>[-1.2]</td>
<td>0.7</td>
<td>3</td>
<td>6</td>
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Table A.20: Minimum reserve requirements of contract proposals of the aggregator

<table>
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<th>D_{Resup/dn}^{1,t}</th>
<th>D_{Resup/dn}^{2,t}</th>
<th>D_{Resup/dn}^{3,t}</th>
<th>D_{Resup/dn}^{4,t}</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.7</td>
<td>2.3</td>
<td>0.4</td>
<td>1.2</td>
</tr>
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</table>
Table A.21: Time series of consumer demand based on consumer type

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<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
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</thead>
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<tr>
<td>I</td>
<td>4.97</td>
<td>3.99</td>
<td>3.50</td>
<td>2.89</td>
<td>2.73</td>
<td>2.52</td>
<td>2.73</td>
<td>2.89</td>
</tr>
<tr>
<td>II</td>
<td>7.45</td>
<td>5.98</td>
<td>5.25</td>
<td>4.33</td>
<td>4.09</td>
<td>3.78</td>
<td>4.09</td>
<td>4.33</td>
</tr>
<tr>
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<td>10.50</td>
<td>10.50</td>
<td>10.50</td>
<td>10.50</td>
<td>10.50</td>
<td>10.50</td>
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</tr>
<tr>
<td>t</td>
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<th>21</th>
<th>22</th>
<th>23</th>
<th>24</th>
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<tbody>
<tr>
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<td>7.49</td>
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<td>9.89</td>
<td>10.99</td>
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<td>6.02</td>
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<tr>
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<td>42.00</td>
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<td>17.50</td>
<td>14.00</td>
<td>12.25</td>
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Table A.22: Technical data of the load

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<th>$E_{\text{Final}}$ [MWh]</th>
<th>$E_{\text{max}}$ [MWh]</th>
<th>$E_{\text{min}}$ [MWh]</th>
<th>$\mu_{\text{disch}}$</th>
<th>$\mu_{\text{ch}}$</th>
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<td>0.125</td>
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<td>0.9</td>
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<tr>
<td>L2</td>
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<td>0.25</td>
<td>0.5</td>
<td>0</td>
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<td>0.9</td>
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<tr>
<td>L3</td>
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<td>0.625</td>
<td>1.25</td>
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Table A.23: Estimated cost factors of up/down reserve capacity for different load types providing DR ($\frac{\text{m.u.}}{\text{MW}}$)

<table>
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<tr>
<th></th>
<th>$\bar{a}_{\text{Resup/dn,cap}}$</th>
<th>$\bar{b}_{\text{Resup/dn,cap}}$</th>
<th>$\bar{c}_{\text{Resup/dn,cap}}$</th>
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<td>6.5/6.5</td>
<td>0.3/0.3</td>
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<td>L2</td>
<td>0.3/0.4</td>
<td>7.5/7.5</td>
<td>1.35/1.35</td>
</tr>
<tr>
<td>L3</td>
<td>0.3/0.4</td>
<td>7.5/7.5</td>
<td>1.35/1.35</td>
</tr>
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</table>
Appendix B

B.1 Chapter II

B.1.1 Clarke-Groves Mechanism

The formal representation of a preference revelation mechanism for the special case of quasilinear preferences (linear in one argument) is given. The analysis follows Chapter 23 in ref. [133]. It is assumed that consumer \( i \) can choose between \( x = (k, z_1, \ldots, z_I) \), where \( k \) is an element in a finite set \( K \) (i.e. the level of reserve capacity), and \( z^i \in \mathbb{R} \) is a transfer of a numeraire commodity, i.e. money. The numeraire is the entity in which the relative prices of all other goods are expressed. The utility function of the agent has a quasilinear form:

\[
    u^i(x, \theta^i) = \mu^i(k, \theta^i) + (m^i + z^i), \tag{B.1}
\]

where \( m^i \) is the endowment of the numeraire of agent \( i \). In case of no outside financing the set of alternatives is given as:

\[
    X = \{(k, t_1, \ldots, t_I) : k \in K, z_i \in \mathbb{R} \forall i, \text{ and } \sum_i z^i \leq 0\}.
\]

Before continuing, several terms have to be defined [133]:

- **Social Choice Function**: The social choice is a function \( f: \Theta^1 \times \ldots \times \Theta^I \to X \) which assigns for each profile of agents’s types \((\theta^1, \ldots, \theta^I)\) a collective choice \( f(\theta^1, \ldots, \theta^I) \in X \). (Def. 23.B.1)

- **Strategy**: A strategy \( s^i \) is any alternative an agent \( i \) can choose from given several choices. It lies in the strategy set \( S^i \). The feedback depends also on the action of other individuals’ choice.
Appendix B.

- **Mechanism** A mechanism $\Gamma = (S^1, ..., S^I, g(\cdot))$ is a collection of $I$ strategy sets $(S^1, ..., S^I)$ and an outcome function $g: S^1 \times ... \times S^I \rightarrow X$. The mechanism implements a social choice function if there is an equilibrium strategy profile $(s^1_\ast(\cdot), ..., s^I_\ast(\cdot))$ of the game induced by $\Gamma$, such that $g(s^1_\ast(\theta_1), ..., s^I_\ast(\theta^I)) = f(\theta^1, ..., \theta^I)$ for all $(\theta^1, ..., \theta^I) \in \Theta^1 \times ... \times \Theta^I$. (Def. 23.B.3-23.B.5)

- **Truthfully Implementable Dominant Strategies**: The social choice function $f(\cdot)$ is truthfully implementable (or incentive compatible) if the mechanism $\Gamma = (\Theta^1, ..., \Theta^I, f(\cdot))$ has an equilibrium $(s^1_\ast(\cdot), ..., s^I_\ast(\cdot))$ in which $s^i_\ast(\theta^i) = \theta^i$ for all $\theta^i = \Theta^i$ and all $i = 1, ..., I$; that is, if truth telling by each agent $i$ constitutes an equilibrium of $\Gamma = (\Theta^1, ..., \Theta^I, f(\cdot))$ (Def. 23.C.2).

A social choice function in the quasilinear setting takes the form $f(\cdot) = (k(\cdot), z^1(\cdot), ..., z^I(\cdot))$, where $\forall \theta \in \Theta$, $k(\theta) \in K$ and $\sum_i z^i \leq 0$. For the social choice function $f(\cdot)$ to be Pareto, $k(\theta)$ must satisfy:

$$\sum_{i=1}^I \mu^i(k(\theta), \theta^i) \geq \sum_{i=1}^I \mu^i(k, \theta^i), \forall k \in K. \quad (B.2)$$

That means that given the profiles $\theta = (\theta^1, ..., \theta^I)$, the alternative $k(\theta)$ is Pareto optimal given the utility function $u^1, ..., u^I$. If a function $k^\ast(\cdot)$ satisfies (B.2), the social choice function is truthfully implementable in dominant strategies $\forall i = 1, ..., I$, if

$$z^i(\theta) = \left[ \sum_{j \neq i} v^j(k^\ast(\theta), \theta^j) \right] + h^i(\theta^{-i}). \quad (B.3)$$

Function $h^i(\theta^{-i})$ is an arbitrary function of $\theta^{-i}$, where $-i$ indicates all individuals except $i$. A direct revelation mechanism which satisfies (B.2) and (B.3) is known as Groves mechanism [147]. A special variant of a Groves mechanism is presented in ref. [43] where agent $i$’s transfer is given by

$$z^i(\theta) = \left[ \sum_{j \neq i} v^j(k^\ast(\theta), \theta^j) \right] - \left[ v^j(k^{-i\ast}(\theta^{-i}), \theta^j) \right], \quad (B.4)$$

which is known as Clarke mechanism. Note that payments are only greater than zero as long as the individual has an influence on the market outcome, he is pivotal.
B.1.2 Energy-Only Unit Commitment Problem

The following constraints (B.5)-(B.25) are partially based on the work of [47] and [53]. The system balance equations for energy is given by:

\[ \sum_{i=1}^{N_G} G_{E_{En}}^{i,t} - \sum_{j=1}^{N_L} D_{E_{En}}^{j,t} = 0, \]  
(B.5)

Constraints (B.6)-(B.7) states the capacity limits of generators and demand:

\[ G_{E_{En}}^{i,t} \leq u_{E_{En}}^{i,t} G_{E_{En}}^{i,t}, \]  
(B.6)

\[ -G_{E_{En,seg}}^{i,1,t} \leq -u_{E_{En}}^{i,t} G_{E_{En}}^{i,t}, \]  
(B.7)

Constraint (B.8) ensures that the limits of segment-wise production equals the overall generation:

\[ G_{E_{En}}^{i,t} - \sum_{s=1}^{N_S} G_{E_{En}}^{i,s,t} = 0, \]  
(B.8)

Constraints (B.9) are further segment-wise constraints for generators:

\[ 0 \leq G_{E_{En,seg}}^{i,s,t} \leq u_{E_{En}}^{i,t}[E_{G}^{i,s} - E_{G}^{i,(s-1)}], \]  
(B.9)

The start-up costs are assumed to be fixed and are defined by,

\[ C_{Start}^{i,t} \geq 0, \]  
(B.10)

\[ C_{Start}^{i,t} \geq \overline{C}(u^{i,t} - u^{i,t-1}), t = 2 \ldots N_T, \]  
(B.11)

\[ C_{Start}^{i,t} \geq \overline{C}(u^{i,t} - 0), t = 1, \]  
(B.12)

where \( u_{0}^{i} \) is the initial on/off state of the generator. The up and down time limits for a generator are given by (B.14)-(B.18):

\[ u_{it} = \begin{cases} 1 & \text{if } t' \leq t_{Up}^{i} - u_{t}^{i,0} \text{ and } t_{Up}^{i} \geq u_{t}^{i,0} \geq 0, \\ 0 & \text{if } t' \leq t_{Dn}^{i} + u_{t}^{i,0} \text{ and } -t_{Dn}^{i} \leq u_{t}^{i,0} \leq 0, \end{cases} \]  
(B.14)

with

\[ u^{i,t} - u^{i,(t-1)} \leq u^{G,i,t''}, \]  
(B.15)

\[ u^{i,(t-1)} - u^{i,t} \leq u^{G,i,t''}, \]  
(B.16)
The ramping limits of a generator are given by equations (B.19)-(B.24)

\[ G_{En}^{i, t} - G_{En}^{i, (t-1)} \leq \min[\overline{G}_{Rup}^{i, t}, \overline{G}_{Rdn}^{i, t}], \quad (B.19) \]
\[ G_{En}^{i, (t-1)} - G_{En}^{i, t} \leq \max[\overline{G}_{Rup}^{i, t}, \overline{G}_{Rdn}^{i, t}], \quad (B.20) \]

where \( \overline{G}_{Rup}^{i, t} \) and \( \overline{G}_{Rdn}^{i, t} \) are dependent upon the operational state of the power plant and are determined by a approach proposed by [148]. For the co-optimization this maximal ramping rates are assumed to be fixed.

\[ 1 - u^{i, t} + u^{i, (t-1)} \leq M [1 - aux^{i, t, 1}], \quad (B.21) \]
\[ G_{En}^{i, t} - G_{En}^{i, (t-1)} - \overline{G}_{Rup}^{i, t} \leq M aux^{i, t, 1}, \quad (B.22) \]
\[ 1 + u^{i, t} - u^{i, (t-1)} \leq M [1 - aux^{i, t, 2}], \quad (B.23) \]
\[ -G_{En}^{i, t} + G_{En}^{i, (t-1)} - \overline{G}_{Rdn}^{i, t} \leq M aux^{i, t, 2} \quad (B.24) \]

The transmission constraints are modeled as

\[ -f_{\text{max}}^{l} \leq PTDF_{l}^{p} (M_{G} \cdot G_{En}^{i, t} - M_{L} \cdot D_{En}^{j, t}) \leq f_{\text{max}}^{l}. \quad (B.25) \]

where \( PTDF_{l}^{p} \) is the Power Transfer Distribution Factor Matrix \( (N_{Br} \times N_{B}) \), which gives the impact of an injection at nodes \( p \) on the load flow at lines \( l \). \( M_{G} \) is the matrix \( N_{B} \times N_{G} \) where every element indicates the location of a generator in the network with one or zero. \( M_{L} \) is the matrix \( N_{B} \times N_{L} \) where every element indicates the location of a load in the network with one or zero.

### B.1.3 Clarke-Groves Mechanism Non-Event Reserves

As shown in B.1a, the pigmented area below the system cost curve, \( Ar_{1} \) is determined by the total aggregation of all marginal cost curves \( MC_{ab}^{\text{novevt}} \) and the cost curve aggregation with the highest cost impact if one cost curve is removed from the total aggregation, \( MC_{ab}^{\text{novevt, min1}} \). Any other combination of cost curves excluding on cost curve, \( MC_{ab}^{\text{novevt, j}} \), is between these bounds and via the respective clearing quantities for abated balancing effort or ramping effort in \( PD_{ab}^{MC} \),
$PD_{ab}^j$, and $PD_{ab}^{min}$ the shaded and pigmented area, $Ar_1$, below the system cost curve can be determined. In a second step, illustrated in B.1b, area $Ar_2$ can be split into $Ar_3$ and $Ar_4$ via using the clearing results from the Lindahl equilibrium and the case of a removal of one cost curve from the total aggregation of cost curves. $Ar_4$ is now equal to the incentive payments following Clarke-Groves.

![Graphical illustration of procedure to determine incentive payments in case of non event-based reserve clearing based on Clarke-Groves mechanism.](image)

Figure B.1: Graphical illustration of procedure to determine incentive payments in case of non event-based reserve clearing based on Clarke-Groves mechanism.

### B.1.4 Co-Optimization

The following constraints (B.26)-(B.89) are partially based on the work of [47] and [53]. They represent the most important parts of the co-optimization problem. The system balance equations for energy and up/down event-based and non event-based reserves are given by:

$$
\sum_{i=1}^{N_G} G_{En}^{i,t} - \sum_{j=1}^{N_L} D_{En}^{j,t} = 0,
$$

(B.26)

The amount of scheduled spinning reserves is the minimum between an externally set quantity and a market based solution based on the
individual valuation of event-based reserves:

\[
\sum_{i=1}^{N_G} G_{Resup,\text{cap}}^{\text{evt},i,t} - \min(R_{\text{Req,Resup,\text{cap}}}^{\text{evt},t}, D_{\text{Resup,\text{cap}}}^{\text{evt},t}) = 0, \quad (B.27)
\]

\[
\sum_{i=1}^{N_G} G_{Resdn,\text{cap}}^{\text{evt},i,t} - \min(R_{\text{Req,Resdn,\text{cap}}}^{\text{evt},t}, D_{\text{Resdn,\text{cap}}}^{\text{evt},t}) = 0, \quad (B.28)
\]

The power balance for non event-driven reserve capacity is given by:

\[
R_{\text{Req,Resup,\text{cap}}}^{\text{noevt},t} - \sum_{j=1}^{N_L} P_{\text{noevt},j,t}^{\text{Resup,\text{ab}}} = R_{\text{Reqrelax,Resup,\text{cap}}}^{\text{noevt},t}, \quad (B.29)
\]

\[
R_{\text{Req,Resdn,\text{cap}}}^{\text{noevt},t} - \sum_{j=1}^{N_L} P_{\text{noevt},j,t}^{\text{Resdn,\text{ab}}} = R_{\text{Reqrelax,Resdn,\text{cap}}}^{\text{noevt},t}, \quad (B.30)
\]

\[
R_{\text{Reqrelax,Resup}}^{\text{noevt},t} - \sum_{i=1}^{N_G} G_{\text{Resup,\text{cap}}}^{\text{noevt},i,t} = 0, \quad (B.31)
\]

\[
R_{\text{Reqrelax,Resdn}}^{\text{noevt},t} - \sum_{i=1}^{N_G} G_{\text{Resdn,\text{cap}}}^{\text{noevt},i,t} = 0, \quad (B.32)
\]

where \( R_{\text{Reqrelax,Resup,\text{cap}}}^{\text{noevt},t} \) is the amount of reserves which has to be provided by generators. \( R_{\text{Req,Resup,\text{cap}}}^{\text{noevt},t} \) is the initial amount of reserves determined by the system operator under the assumption of no decentralized balancing efforts. The amount of deployed reserve energy per hour is assumed to be half of the hourly scheduled reserve energy. This numeric assumption can be replaced e.g. in the course of a two-stage stochastic co-optimization problem. However, the additional computational effort for this case would be significant and is out of the scope of this work:

\[
R_{\text{Req,Resup,\text{en}}}^{\text{noevt},t} - R_{\text{Reqrelax,Resup,\text{cap}}}^{\text{noevt},t} = 0.5 = 0, \quad (B.34)
\]

\[
R_{\text{Req,Resdn,\text{en}}}^{\text{noevt},t} - R_{\text{Reqrelax,Resdn,\text{cap}}}^{\text{noevt},t} = 0.5 = 0, \quad (B.35)
\]

\[
R_{\text{Resup,\text{cap}}}^{\text{noevt},t} - \min(R_{\text{Req,Resup,\text{cap}}}^{\text{evt},t}, D_{\text{Resup,\text{cap}}}^{\text{evt},t}) = 0.5 = 0, \quad (B.36)
\]

\[
R_{\text{Resdn,\text{cap}}}^{\text{noevt},t} - \min(R_{\text{Req,Resdn,\text{cap}}}^{\text{evt},t}, D_{\text{Resdn,\text{cap}}}^{\text{evt},t}) = 0.5 = 0, \quad (B.37)
\]
where

\[ R_{\text{Req,Resup,en}}^{\text{noevt},t} - \sum_{j=1}^{N_G} G_{\text{Resup,en}}^{\text{noevt},i,t} = 0, \quad \text{(B.38)} \]

\[ R_{\text{Req,Resdn,en}}^{\text{noevt},t} - \sum_{j=1}^{N_G} G_{\text{Resdn,en}}^{\text{noevt},i,t} = 0. \quad \text{(B.39)} \]

Constraints (B.40)-(B.41) state the capacity limits of generators and demand:

\[ G_{\text{En}}^{i,t} + G_{\text{Resup}}^{\text{evt},i,t} + G_{\text{Resup}}^{\text{noevt},i,t} \leq u_{i,t} G_{\text{En}}^{i,t}, \quad \text{(B.40)} \]

\[ -G_{\text{En,Seg}}^{i,1,t} + G_{\text{Resdn,seg}}^{\text{evt},i,1,t} + G_{\text{Resdn,seg}}^{\text{noevt},i,1,t} \leq -u_{i,t} G_{\text{En}}^{i,t}, \quad \text{(B.41)} \]

Constraints (B.42)-(B.43) ensure that the sum of segment-wise power production and consumption equals the overall generation/consumption:

\[ G_{\text{En}}^{i,t} - \sum_{s=1}^{N_S} G_{\text{En,seg}}^{i,s,t} = 0, \quad \text{(B.42)} \]

\[ G_{\text{Resup/dn,cap}}^{\text{noevt},i,t} - \sum_{s=1}^{N_S} G_{\text{Resup/dn,cap,seg}}^{\text{noevt},i,s,t} = 0, \quad \text{(B.43)} \]

\[ G_{\text{Resup/dn,cap}}^{\text{evt},i,t} - \sum_{s=1}^{N_S} G_{\text{Resup/dn,cap,seg}}^{\text{evt},i,s,t} = 0, \quad \text{(B.44)} \]

\[ G_{\text{Resup/dn,en}}^{\text{noevt},i,t} - \sum_{s=1}^{N_S} G_{\text{Resup/dn,en,seg}}^{\text{noevt},i,s,t} = 0, \quad \text{(B.45)} \]

\[ G_{\text{Resup/dn,en}}^{\text{evt},i,t} - \sum_{s=1}^{N_S} G_{\text{Resup/dn,en,seg}}^{\text{evt},i,s,t} = 0, \quad \text{(B.46)} \]

Constraints (B.47-B.49) is segment-wise constraints for generation, event-based reserve demand, and non event-based reserve capacity abatement:

\[ 0 \leq G_{\text{En,seg}}^{i,s,t} + G_{\text{Resup,cap,seg}}^{\text{evt},i,s,t} + G_{\text{Resup,cap,seg}}^{\text{noevt},i,s,t} \leq u_{i,t} [E_G^{i,s,t} - E_G^{i,s-1,t}], \quad \text{(B.47)} \]

\[ 0 \leq D_{\text{Resup/dn,seg}}^{\text{evt},p,t} \leq [E_D^{\text{evt},p,t} - E_D^{\text{evt},p-1,t}], \quad \text{(B.48)} \]
0 \leq P_{\text{Resup/dn,ab,seg}}^{\text{noevt},q,t} \leq [E_P^{\text{noevt},q,t} - E_P^{\text{noevt},q-1,t}],
(B.49)

Constraints (B.50)-(B.59) are necessary to achieve a correct bidding for non-event driven reserves capacity (see also [47])

\[ u_{\text{Resup,cap}}^{\text{evt},i,s,t} \geq u_{\text{Resup,cap}}^{\text{evt},i,(s+1),t}, \quad (B.50) \]
\[ M \cdot MC_{\text{Resup,cap,seg}}^{\text{evt},j,s,t} \geq u_{\text{Resup,cap}}^{\text{evt},i,s,t}, \quad (B.51) \]
\[ M \cdot u_{\text{Resup,cap}}^{\text{noevt},i,s,t} \geq MC_{\text{Resup,cap,seg}}^{\text{noevt},j,s,t}, \quad (B.52) \]
\[ M \cdot u_{\text{Resup,cap}}^{\text{noevt},i,s,t} \geq MC_{\text{Resup,cap,seg}}^{\text{noevt},j,s,t}, \quad (B.53) \]
\[ M \cdot [1 - u_{\text{Resup,cap}}^{\text{evt},i,(s+1),t}] - H_{\text{Resup}}^{i,s,t} \geq 0, \quad (B.56) \]
\[ M \cdot [1 - u_{\text{Resup,cap}}^{\text{no evt},i,(s+1),t}] - V_{\text{Resup}}^{i,s,t} \geq 0, \quad (B.57) \]

for \( s = 1, \ldots (N_{G,\text{segm}} - 1) \) where,

\[ H_{\text{Resup}}^{i,s,t} = [E_G^i - E_G^{i,(s-1)}] - G_{\text{En,seg}}^{i,s,t} - G_{\text{Resup,cap,seg}}^{\text{evt},i,s,t}, \quad (B.58) \]
\[ V_{\text{Resup}}^{i,s,t} = [E_G^i - E_G^{i,(s-1)}] - G_{\text{En,seg}}^{i,s,t} - G_{\text{Resup,cap,seg}}^{\text{noevt},i,s,t} - G_{\text{Resup,cap,seg}}^{\text{noevt},i,s,t}. \quad (B.59) \]

Note that if,

\[ H_{\text{Resup}}^{i,s,t} \begin{cases} > 0 & \text{then } u_{\text{Resup,cap}}^{\text{evt},i,s+1,t}, \\ = 0 & \text{then } u_{\text{Resup,cap}}^{\text{evt},i,s+1,t}, \end{cases} \]

for \( s = 1, \ldots (N_{G,\text{segm}} - 1) \), and if

\[ V_{\text{Resup}}^{i,s,t} \begin{cases} > 0 & \text{then } u_{\text{Resup,cap}}^{\text{noevt},i,s+1,t}, \\ = 0 & \text{then } u_{\text{Resup,cap}}^{\text{noevt},i,s+1,t}, \end{cases} \]

for \( s = 1, \ldots (N_{G,\text{segm}} - 1) \). The piecewise linear down-reserve offer is given by constraints

\[ u_{\text{Resdn,cap}}^{\text{evt},i,s,t} \geq u_{\text{Resdn,cap}}^{\text{evt},i,s-1,t}, \quad (B.60) \]
\[ u_{\text{Resdn,cap}}^{\text{noevt},i,s,t} \geq u_{\text{Resdn,cap}}^{\text{noevt},i,s-1,t}. \quad (B.61) \]
\[
M \cdot [1 - u_{\text{Resdn,cap}}^{\text{evt},i,(s-1),t}] - H_{\text{Resdn}}^{i,s,t} \geq 0, \quad (B.62)
\]
\[
M \cdot [1 - u_{\text{Resdn,cap}}^{\text{noevt},i,(s-1),t}] - V_{\text{Resdn}}^{i,s,t} \geq 0, \quad (B.63)
\]
\[
M \cdot \text{MC}_{\text{Resdn,cap,seg}}^{\text{evt},j,s,t} \geq u_{\text{Resdn,cap}}^{\text{evt},i,s,t}, \quad (B.64)
\]
\[
\text{MC}_{\text{Resdn,cap,seg}}^{\text{evt},j,s,t} \leq M \cdot u_{\text{Resdn,cap}}^{\text{evt},i,s,t}, \quad (B.65)
\]
\[
M \cdot \text{MC}_{\text{Resdn,cap,seg}}^{\text{noevt},j,s,t} \geq u_{\text{Resdn,cap}}^{\text{noevt},i,s,t}, \quad (B.66)
\]
\[
\text{MC}_{\text{Resdn,cap,seg}}^{\text{noevt},j,s,t} \leq M \cdot u_{\text{Resdn,cap}}^{\text{noevt},i,s,t}, \quad (B.67)
\]

for \(s = 1, \ldots (N_{G,\text{segm}} - 1)\), where

\[
H_{\text{Resdn}}^{i,s,t} = G_{\text{En,seg}}^{i,s,t} - G_{\text{Resdn,cap,seg}}^{\text{evt},i,s,t}, \quad (B.68)
\]
\[
V_{\text{Resdn}}^{i,s,t} = G_{\text{En,seg}}^{i,s,t} - G_{\text{Resdn,cap,seg}}^{\text{evt},i,s,t} - G_{\text{Resdn,cap,seg}}^{\text{noevt},i,s,t}. \quad (B.69)
\]

Note that if,

\[
H_{\text{Resdn}}^{i,s,t} \begin{cases} > 0 & \text{then } u_{\text{Resdn,cap}}^{\text{evt},i,s-1,t}, \\ = 0 & \text{then } u_{\text{Resdn,cap}}^{\text{evt},i,s-1,t}, \end{cases}
\]

and

\[
V_{\text{Resdn}}^{i,s,t} \begin{cases} > 0 & \text{then } u_{\text{Resdn,cap}}^{\text{noevt},i,s-1,t}, \\ = 0 & \text{then } u_{\text{Resdn,cap}}^{\text{noevt},i,s-1,t}, \end{cases}
\]

for \(s = 1, \ldots (N_{G,\text{segm}} - 1)\).

The lost opportunity costs for event-driven and non-event driven reserves are given by constraints (B.70)-(B.71).

\[
\text{LOC}_{\text{seg}}^{\text{evt},i,t} - \sum_{s=1}^{N_{G}} \text{LOC}_{\text{seg}}^{\text{evt},i,s,t} = 0, \quad (B.70)
\]
\[
\text{LOC}_{\text{seg}}^{\text{noevt},i,t} - \sum_{s=1}^{N_{G}} \text{LOC}_{\text{seg}}^{\text{noevt},i,s,t} = 0, \quad (B.71)
\]

\[
\text{LOC}_{\text{seg}}^{\text{evt},i,s,t} = M_G' \lambda_{p,t} M_G G_{\text{Resup,cap,seg}}^{\text{evt},i,s,t} - M_G M_{\text{En,seg}} G_{\text{Resup,cap,seg}}^{\text{evt},i,s,t}, \quad (B.72)
\]
\[
\text{LOC}_{\text{seg}}^{\text{noevt},i,s,t} \geq 0. \quad (B.73)
\]
\[
\text{LOC}_{\text{seg}}^{\text{noevt},i,s,t} = M_G' \lambda_{p,t} M_G G_{\text{Resup,cap,seg}}^{\text{noevt},i,s,t} - M_G M_{\text{En,seg}} G_{\text{Resup,cap,seg}}^{\text{noevt},i,s,t}, \quad (B.74)
\]
\[
\text{LOC}_{\text{seg}}^{\text{noevt},i,s,t} \geq 0. \quad (B.75)
\]
The up and down time limits for a generator are given by (B.76)-(B.80):

\[
u_{it} = \begin{cases} 
1 & \text{if } t' \leq t_{\text{Resup}}^i - u_{i,0}^t \text{ and } t_{\text{Resup}}^i \geq u_{i,0}^t \geq 0, \\
0 & \text{if } t' \leq t_{\text{Resdn}}^i + u_{i,0}^t \text{ and } -t_{\text{Resdn}}^i \leq u_{i,0}^t \leq 0,
\end{cases}
\]  

(B.76)

with

\[
u_{i,t}^i - u_{i,(t-1)}^i \leq u_{i,t''}^i,
\]  

(B.77)

\[
u_{i,(t-1)}^i - u_{i,t}^i \leq u_{i,t''}^i,
\]  

(B.78)

\[t + 1 \leq t'' \leq t + t_{\text{Resup}}^i - 1 \text{ and } t = 2...T,
\]  

(B.79)

\[t + 1 \leq t''' \leq t + t_{\text{Resdn}}^i - 1 \text{ and } t = 2...T.
\]  

(B.80)

The ramping limits of a generator are given by equations (B.81)-(B.86)

\[
G_{\text{En}}^{i,t} - G_{\text{En}}^{i,(t-1)} \leq \max\{\overline{G}_{\text{Rup}}^{i,t}, G_{\text{En}}^{i,t}\},
\]  

(B.81)

\[
G_{\text{En}}^{i,(t-1)} - G_{\text{En}}^{i,t} \leq \max\{\overline{G}_{\text{Rdn}}^{i,t}, G_{\text{En}}^{i,t}\},
\]  

(B.82)

\[
1 - u_{i,t}^i + u_{i,(t-1)}^i \leq M[1 - aux_{i,t,1}^{i,1}],
\]  

(B.83)

\[
G_{\text{En}}^{i,t} - G_{\text{En}}^{i,(t-1)} - \overline{G}_{\text{Rup}}^{i,t} \leq M aux_{i,t,1}^{i,1},
\]  

(B.84)

\[
1 + u_{i,t}^i - u_{i,(t-1)}^i \leq M[1 - aux_{i,t,2}^{i,2}],
\]  

(B.85)

\[-G_{\text{En}}^{i,t} + G_{\text{En}}^{i,(t-1)} - \overline{G}_{\text{Rdn}}^{i,t} \leq M aux_{i,t,2}^{i,2},
\]  

(B.86)

\[
\sum_{i=1}^{N_G} \min\{G_{\text{max}}^{i,t}, G_{\text{En}}^{i,t} + \overline{G}_{\text{Rup}}^{i,t}\} \geq \sum_{j=1}^{N_L} G_{\text{En}}^{j,t} + G_{\text{En}}^{\text{cap,Resup}}^t + R_{\text{Reqrelax,Resup}}^t,
\]  

(B.87)

\[
\sum_{i=1}^{N_G} \min\{G_{\text{min}}^{i,t}, G_{\text{En}}^{i,t} - \overline{G}_{\text{Rdn}}^{i,t}\} \geq \sum_{j=1}^{N_L} G_{\text{En}}^{j,t} - G_{\text{En}}^{\text{cap,Resdn}}^t - R_{\text{Reqrelax,Resdn}}^t,
\]  

(B.88)

The transmission constraints are modeled as,

\[-f_{\text{max}}^l \leq PTDF^p_{l} (M_G \cdot G_{\text{En}}^{i,t} - M_L \cdot G_{\text{En}}^{j,t}) \leq f_{\text{max}}^l.
\]  

(B.89)

where \(PTDF^p_l\) is the Power Transfer Distribution Factor Matrix \((N_{Br} \times N_B)\), which gives the impact of an injection at nodes \(p\) on the load flow at lines \(l\). \(M_G\) is the matrix \(N_B \times N_G\) where every element indicates the location of a generator in the network with one or zero. \(M_L\) is the matrix \(N_B \times N_L\) where every element indicates the location of a load in the network with one or zero. All decision variables are greater or equal zero.
B.1. Chapter II

B.1.5 Relaxation of Quadratic Constraints

Equations (2.10)-(2.9) can be rewritten as:

\[ c_{i,t}^{up,q} \geq G_{En}^i t - G_{En}^{i-1} t^2, \forall i, t \]

\[ c_{i,t}^{dn,q} \geq G_{En}^i t - G_{En}^{i} t^2, \forall i, t \]

\[ c_{i,t}^{up,b} \geq G_{En}^i t - G_{En}^{i-1} t^2, \forall i, t \]

\[ c_{i,t}^{dn,b} \geq G_{En}^i t - G_{En}^{i} t^2, \forall i, t. \]

These equations can be rewritten to quadratic constraints following [149]:

\[ x^T Q_k x + a_k^T x + b_k^T y \leq c_k, \text{ for } k = 1, 2, ..., K \quad (B.90) \]

\[ l_{x,i,t} \leq x^{i,t} \leq u_{x,i,t}, \text{ for } i = 1, 2, ..., |I| \quad (B.91) \]

\[ l_{y,j,t} \leq y^{j,t} \leq u_{y,j,t}, \text{ for } j = 1, 2, ..., m \quad (B.92) \]

where \( i \) refers to generator \( i \in N_G \) and time instant \( t \). The number of quadratic constraints \( K = 4 \times N_G \times N_T \). Constraints (B.91) refer to the generator limits at time \( t \) and (B.92) covers other possible variables. Since the Hessian matrix of the quadratic terms is not positive definite, a rewriting of the constraints following ref. [150] is not possible. However, equations (B.90)-(B.92) can relaxed [151]:

\[ \tilde{Q}_k \cdot \tilde{X} + b_k^T y \leq 0, \text{ for } k = 1, 2, ..., K \quad (B.93) \]

\[ l_{x,i,t} \leq x^{i,t} \leq u_{x,i,t}, \text{ for } i = 1, 2, ..., |I| \quad (B.94) \]

\[ l_{y,j,t} \leq y^{j,t} \leq u_{y,j,t}, \text{ for } j = 1, 2, ..., m \quad (B.95) \]

\[ \tilde{X} = X^T. \quad (B.96) \]

In formulation (B.93) - (B.96), the additional relaxation variables have to be related to the original decision variables. Following [149] and [152] semidefinite or linear reformulations can therefore be applied. We follow [153] and combine both methods which gives the following reformulation for the quadratic constraints:

\[ \tilde{Q}_k \cdot \tilde{X} \leq 0, \text{ for } k = 1, 2, ..., K = 4 \times N_G \times N_T \quad (B.97) \]

\[ l_{x,i,t} \leq x^{i,t} \leq u_{x,i,t}, \text{ for } i = 1, 2, ..., N_G \quad (B.98) \]

\[ l_{y,j,t} \leq y^{j,t} \leq u_{y,j,t}, \text{ for } j = 1, 2, ..., m \quad (B.99) \]

\[ \tilde{X} \succeq 0, \quad (B.100) \]
Table B.1: Objective value and ramping costs in case of substitution of power balance constraint with energy balance constraint and different variants of relaxing quadratic constraints.

<table>
<thead>
<tr>
<th>Method</th>
<th>Rel</th>
<th>Lin</th>
<th>SDP</th>
<th>Lin + SDP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Obj</td>
<td>1.83</td>
<td>8.93</td>
<td>1.88</td>
<td>2.33</td>
</tr>
<tr>
<td>RC</td>
<td>$2.5 \times 10^4$</td>
<td>$2.3 \times 10^5$</td>
<td>$2.7 \times 10^4$</td>
<td>$3.1 \times 10^4$</td>
</tr>
</tbody>
</table>

where $\tilde{X}$ and $\tilde{Q}_k$ are defined following [153]:

$$\tilde{X} = \begin{pmatrix} 1 \\ x^T \\ X \end{pmatrix} \quad \tilde{Q}_k = \begin{pmatrix} -c_k \\ a_k^T / 2 \\ Q_k \end{pmatrix}.$$ 

"$A \bullet B$" defines the Frobenius Product of two matrices $A$ and $B$. Further, the elements $uv$ of the matrix $X$ $[2 \times N_G \times 2 \times N_G]$ are constrained by,

$$X_{uv} - l_{x^u}x^v - l_{x^v}x^v \geq -l_{x^u}l_{x^v},$$  \hspace{1cm} (B.101)

$$X_{uv} - u_{x^u}x^v - u_{x^v}x^v \geq -u_{x^u}u_{x^v},$$  \hspace{1cm} (B.102)

$$X_{uv} - l_{x^u}x^v - u_{x^u}x^v \leq -l_{x^u}u_{x^v},$$  \hspace{1cm} (B.103)

$$X_{uv} - l_{x^u}x^v - l_{x^v}x^v \leq -u_{x^u}l_{x^v},$$  \hspace{1cm} (B.104)

where $x^u$ refers to generator $i$ at time $t$, $x^v$ to the generator at time $t+1$. The time steps are connected via the constraint:

$$X_{uv} = X_{u'v'},$$  \hspace{1cm} (B.105)

where $u = N_G \ldots 2 \times N_G$, $v = N_G \ldots 2 \times N_G$, $u' = 1 \ldots N_G$, and $v' = 1 \ldots N_G$. Different relaxation variants were tested on simple 3 generator unit commitment with fixed demand provided in [55]. Linear costs of production were assumed and the solution with a power balance equation was compared with the solution including an energy balance equation similar to (2.12). Table B.1 shows the results in terms of the value of the objective function (Obj) and the explicit costs of ramping costs (RC): $Rel$ refers to a relaxation according to (B.93)-(B.96). In $Lin$, for $t = 2 \ldots N_T$, linear constraints were applied to connect the relaxation variables with the original decision variables following equations (B.101)-(B.104). In $SDP$, for $t = 2 \ldots N_T$ semidefinite constraints according to (B.97)-(B.100) were applied. Approach $SDP + RLT$ combines previous approaches and gives the most realistic results in terms of ramping costs.
B.2 Chapter III

B.2.1 Approximation of Probabilistic Constraints

The so called “scenario approach” that was proposed in [74], provides a way to solve chance constraint problems. Under a convexity assumption (which is satisfied in the formulation (3.15)-(3.17)), the main idea of ref. [74] is to consider only a finite number of scenarios of the uncertain parameter (in this case the wind power forecast error), and then solve the corresponding linear program. The important issue is that the authors of [74] provide a lower bound for the number of scenarios that should be extracted to provide the desired probabilistic guarantees with high confidence. Following [74], the number of samples that one needs to generate is

$$N_s \geq \frac{2}{\epsilon} \left( N_d + \log \frac{1}{\beta} + 1 \right), \quad (B.106)$$

where $\epsilon \in (0, 1)$ is the violation parameter, $\beta \in (0, 1)$ is the confidence level, and $N_d$ is the number of decision variables, which for this case is $N_d = 2$. By generating then $N_s$ samples, the solution of the corresponding problem will violate the chance constraint with probability at most $\epsilon$, with confidence at least $1 - \beta$. Parameter $\beta$ represents the probability of a bad multi-sample (e.g. generate the same scenario $N_s$ times). The advantage of this approach is that $N_s$ scales logarithmically with respect to $\beta$, and hence it has little impact on the computational overhead of the solution. Adopting the “scenario approach”, it is possible to transform the initial chance constrained optimization problem to a linear program. The only prerequisite is to be equipped with a model to generate scenarios of the uncertain parameter, i.e. the wind power injection. To achieve this, it is assumed that wind power injection is the sum of a deterministic component, which is the available forecast, and a stochastic one, which models the error between the forecast and the actual wind power. To construct a realistic wind power error generator, a method introduced in [73] which proposes a Markov chain-based model to generate wind power time series data is used.
B.3 Chapter IV

B.3.1 Non-Linear Pricing

A system operator providing reliability in the supply of electricity has naturally monopoly power. Therefore it can use more complicated pricing strategies to create rewards for these services. The aim of such pricing schemes may not necessarily be profit maximization for the service provider. More sophisticated pricing schemes also encourage individuals to think of alternatives to reduce dependency from the monopoly. Three basic pricing strategies which may be applied in case of monopolistically provided services are presented in ref. [154]:

- **First-Degree price discrimination**: The monopolist sells different amounts of output at different prices dependent upon the stated preferences of the consumer.

- **Second-Degree price discrimination**: The monopolist sells different amounts of output at different prices, but consumers which buy the same quantity receive the same price.

- **Third-Degree price discrimination**: The monopolist sells different amounts to different consumers at different prices, but the price for the every unit sold to a specific consumer remains the same.

In case of a contract with a multipart tariff scheme, i.e. two-part tariff scheme, consumers pay two different prices: One for getting access to the good, and one of actual usage. This tariff scheme has its application in industries with high capital intensity and comparatively low operational costs, i.e. communication or power systems. In such a tariff scheme, price discrimination of first and second order are applied. The basic idea of the two part pricing scheme with one consumer, or several consumers with the same demand, is shown in Fig. B.2: The price-discriminating monopolist sets a fixed price $P_M$ for access to the infrastructure, i.e. a lump-sum fee, equal to its marginal costs $MC$. The resulting demand is $Q_c$. In a second step, the remaining consumer surplus may be extracted with a per unit tariff scheme.
Figure B.2: Two part pricing in case of a monopolistic service provider: First, the monopoly aims that its marginal revenue, \( MR \) is equal to its marginal cost of service provision, \( MC \). Thereby it can set the price \( P_M \) while producing \( Q_M \). The surplus of the monopoly is determined by area \( Ar_B \), the surplus of the consumer by area \( Ar_A \), and the deadweight loss is \( Ar_C \). In case of an additional price discriminating component, the monopoly imposes also a per unit fee and can in the ideal case receive the surplus of areas \( Ar_A \), \( Ar_B \), and \( Ar_C \).

### B.3.2 Mechanism Design for Preference Revelation

In economics, mechanism design is a field which studies solution concepts for a class of games with private information [122]. The analysis is taken from Chapter 14 in ref. [133], and adapted to the case of one monopolistically acting aggregator who provided contracts to two possible types of consumers with different capabilities to provide DR, \( \theta_H \) and \( \theta_L \) where \( \theta_H > \theta_L \). The utility functions of the consumers are given with:

\[
    u(c, t) = c - g(r, \theta),
\]

where \( c \) is the compensation for providing DR services \( r \), and \( g(\cdot) \) is the cost function of providing DR services. The reservation utility, which is the minimum utility necessary to accept a contract, is given with \( \overline{u} \). The fraction of consumers of type \( \theta_H \) is \( \lambda \in (0,1) \). The profits of the aggregator are given with \( \pi_H(t) \) for type \( \theta_H \) and \( \pi_L \) for type \( \theta_L \). Further it is assumed that \( \theta_H'(r) \geq \theta_L'(r) \geq 0 \) for all \( r \geq 0 \).

The aggregators problem is now to offer a set of contracts given the consumers self-selection among the offered contracts. The revelation principles can be used for the aggregators problem.
Appendix B.

The Revelation Principle

Denote the set of possible consumer types with $\Theta$. The aggregator can restrict himself to contracts of the following form:

1. After realization of type $\theta$, the consumer is required to announce which state has occurred.

2. The contract determines an outcome $[c(\hat{\theta}), r(\hat{\theta})]$ for each announcement $\hat{\theta} \in \Theta$.

3. For every type $\theta \in \Theta$, the consumer finds it optimal to report the type truthfully.

Formal Definition Contract Offering

The aggregator provides a contract menu of compensation/DR service pairs $[(c_H, r_H), (c_L, r_L)]$ to solve:

$$\max_{c_H \geq 0, r_H \geq 0, c_L \geq 0, r_L \geq 0} (1 - \lambda)[\pi_L(r_L) - c_L] + \lambda[\pi_H(r_H) - c_H], \quad (B.108)$$

subject to

$$c_L - g(t_L, \theta_L) \geq 7(u),$$

$$c_H - g(t_H, \theta_H) \geq 7(u),$$

$$c_H - g(t_H, \theta_H) \geq c_L - g(t_L, \theta_H),$$

$$c_L - g(t_L, \theta_L) \geq c_H - g(t_H, \theta_L). \quad (B.109)$$

In formulation $(B.108)$-$(B.109)$, the profit of the aggregator is a function of the type.

B.3.3 Non-Linear Tariff Design for Reserve Capacity

A stepwise-linear approximation of $(4.1)$, $(4.2)$ and $(4.3)$ is used [49]. Sets of indices $v = \{j, t\}$, $v' = \{j', t\}$, $w = \{j, t, p\}$, $w' = \{j', t, p\}$ are defined. The indices $j$, $p$, and $t$ refer to BRP $j$, time instant $t$ and segment $p$ of a piecewise linear curve respectively. $j'$ refers to all other BRPs except $j$. The problem of cost allocation in case of reserve
B.3. Chapter IV

capacity is stated as a weighted maximization of the profit of the TSO and the surplus of the BRPs, $SU_{j,t}$:

\[
\max_{\varphi} \sum_{t=1}^{N_T} \left\{ \beta \sum_{j=1}^{N_L} SU_{j,t} + (1 - \beta) \left[ \sum_{j=1}^{N_L} \sum_{p=1}^{N_P} (p_{\text{Resup, var}} - p_{\text{Resup, var}}^*) \times MB_{\text{Resup, cap}} + p_{\text{Resup, fix}}^w \right] \right\},
\]

subject to a no-loss constraint for the TSO:

\[
\sum_{t=1}^{N_T} \sum_{j=1}^{N_{BRP}} \left\{ \sum_{p=1}^{N_P} [(p_{\text{Resup, var}} - p_{\text{Resup, var}}^*) - ((\lambda_{\text{Resup}} M_{\text{BRP}})^t 1^P) \times u^w] \times MB_{\text{Resup, cap}} + p_{\text{Resup, fix}}^w \right\} \geq 0.
\]

The wealth to the BRP $j$ at time $t$, $SU_{j,t}$, is determined by:

\[
\sum_{t=1}^{N_T} \sum_{j=1}^{N_{BRP}} \left\{ B_{\text{Resup, cap}}^w \times u^w - (p_{\text{Resup, var}}^w - p_{\text{Resup, var}}^*) \times MB_{\text{Resup, cap}}^w \right\} - p_{\text{Resup, fix}}^v \geq SU_{j,t} \forall j, s
\]

Further, it has to be ensured that the amount of procured reserves is matched with the demand:

\[
\sum_{j=1}^{N_{BRP}} \sum_{p=1}^{N_P} MB_{\text{Resup, cap}}^{\text{noevt}, w} \times u^w \geq R_{\text{req, Resup, cap}}^{\text{noevt}, t} \forall t
\]

Incentive-based payments are ensured via:

\[
\sum_{t=1}^{N_T} \sum_{p=1}^{N_P} \left\{ B_{\text{cap}}^{\text{noevt}, w'} \times u^{w'} - (p_{\text{Resup, var}}^{w'} - p_{\text{Resup, var}}^*) \times MB_{\text{Resup, cap}}^{\text{noevt}, w'} \right\} - p_{\text{Resup, fix}}^{v'} \geq 0 \forall j, p, t
\]
Constraints (B.115)-(B.119) are necessary for using the right segment on the piecewise cost curve:

\[
\sum_{p=1}^{N_P} u^w \leq 1, \forall j, t \tag{B.115}
\]

\[
p_{\text{Resup, var}}^w - p_{\text{Resup, var}}^* w \leq \sum_{p=1}^{N_P} MB_{\text{Resup, cap}}^{\text{noevt, w}} -1 \times u^w, \forall j, t, p = [1, N_K-1] \tag{B.116}
\]

\[
p_{\text{Resup, var}}^w - p_{\text{Resup, var}}^* w \geq \sum_{p=1}^{N_P} MB_{\text{Resup, cap}}^{\text{noevt, w}} -1 \times u^w, \forall j, t, p = [2, N_K] \tag{B.117}
\]

\[
0 \leq p_{\text{Resup, var}}^w - p_{\text{Resup, var}}^* w \leq u^w M, \forall j, t, p \tag{B.118}
\]

\[
0 \leq p_{\text{Resup, var}}^* w \leq (1 - u^w) M, \forall j, t, p \tag{B.119}
\]

where

\[
\vartheta = \{ p_{\text{Resup, fix}}^w, u^w, p_{\text{Resup, var}}^w, p_{\text{Resup, var}}^* w \}.
\]

and \( M_{BRP} \in \mathbb{R}^{NG \times NB} \), \( 1^P \) is a unity vector of dimension \([1 \times N_P]\),  
\( \lambda_{\text{Resup}}^{\text{noevt, n, t}} \in \mathbb{R}^{NB \times NT} \). All decision variables are greater or equal to zero. Parameter \( NT \) is the number of time periods, and \( NP \) is the number of segments in the stepwise curves. \( p_{\text{fix}}^w \) refers to the fixed part of the nonlinear charge, which is not dependent on the demand of non event-based reserves. \( p_{\text{var}}^w \) is the variable charge part of the cost, which is charged to BRP \( j \) for its individual demand for non event-based AS capacity. \( p_{\text{var}}^* w \) is an auxiliary variable which is necessary to avoid a multiplication of binary and continuous decision variables [144]. \( u^w \) is a binary vector which is used to choose between the different segment of the piece-wise linear curves. \( \lambda_{\text{Resup}}^{\text{noevt, n, t}} \) is the price of the non event-based services at bus \( n \) and time \( t \), \( C_{t}^{\text{fix}} \) are the costs of the event driven system services. \( M_{BRP} \) is the connectivity matrix of BRP \( j \) to bus \( n \) where an element is one if the BRP \( j \) is connected to a certain bus \( n \). The symbol \( \times \) refers to an element-wise matrix multiplication.

Constraint (B.111) ensures that the TSO does have sufficient revenue to cover all procurement costs of system services. Constraint (B.112)
ensures the individual rationality BRP dependent upon its individual willingness to pay for event-based and non-event based reserves. Constraint (B.113) ensures that the total non event-based AS capacity that the BRPs are willing to pay for is at least as equal to the quantity procured by the system operator. Constraint (B.114) ensures incentive compatibility so BRPs reveal their true preferences about non event-based system services. Each BRP is therefore better off by stating its true valuation of AS capacity. Constraint (B.115) allows only one segment on the piecewise-linear willingness to pay functions. Constraints (B.118)-(B.119) ensure that the determined variable charges are in the range of the presented demand curves for non event-based reserves.

B.4 Chapter VI

B.4.1 Bilevel Optimization

Overview

The description of bilevel programming is taken from [134], chapter 1: Bilevel programming is a static version of a a non-cooperative game with two entities [155]. Static means that each player has only one move. The leader attempts to minimize costs and moves first. Thereby, the leader anticipates all possible reaction of its opponent, the follower. The follower observes the leader’s decision and reacts such that it is optimal. Bilevel programming incorporates these features. Suppose that the higher-level decision maker, or lead, has control over the vector \( x \in X \subseteq \mathbb{R}^n \), and that the follower has control over the vector \( y \in Y \subseteq \mathbb{R}^m \). The leader selects an \( x \) in order to minimize \( F(x, y(x)) \) subject to contraints \( G(x, y) \). The follower observes the decision of the leader and reacts by selecting a vector \( y \) which minimizes its objective \( f(x, y) \), subject to the a set of constraints \( g(x, y) \). The general bilevel programming problem can be written as:

\[
\begin{align*}
\min_{x \in X} F(x, y(x)), \\
\text{subject to} \\
H(x, y) &= 0, \\
G(x, y) &\leq 0,
\end{align*}
\]
and

$$\min_{y \in Y} f(x, y),$$

subject to

$$h(x, y) = 0,$$
$$g(x, y) \leq 0,$$

where $F, f : \mathbb{R}^n \times \mathbb{R}^m \to \mathbb{R}^1, G : \mathbb{R}^n \times \mathbb{R}^m \to \mathbb{R}^p$, and $g : \mathbb{R}^n \times \mathbb{R}^m \to \mathbb{R}^q$.

**Solution with Big-M Approach**

One way to solve equation (B.121) is to make use of the KKT - conditions for the lower level problem. In case the problem is convex, the KKT conditions are necessary and sufficient for optimality. Therefore the problem

$$\min_{x \in X, y \in Y, \lambda, \mu} f(x, y(x)),$$

subject to

$$h(x, y) = 0,$$
$$g(x, y) \leq 0,$$

can be rewritten as

$$\nabla_y f(x, y) + \lambda^T \nabla_y h(x, y) + \mu^T \nabla_y g(x, y) = 0,$$
$$h(x, y) = 0,$$
$$g(x, y) \leq 0,$$
$$\mu \geq 0,$$

and

$$\mu^T g(x, y) = 0,$$

where (B.129) is the complementary condition. Using a large constant $M$, equation (B.129) can be rewritten as,

$$\mu \geq 0,$$
$$\mu \leq (1 - z_i)M,$$
$$z_i \in \{0, 1\}.$$

However, one of the major difficulties is finding an appropriate $M$. 
B.4.2 Cooperative Game Theory

In non-cooperative games, players are equipped with a set of possible actions and preferences over the possible outcomes. Each action is taken by a single player autonomously. In contrast, in cooperative games a group of players has a collection of sets of joint actions that the group can choose from, independently from the remaining players. A solution concept assigns to each game a set of possible outcomes.

A cooperative game is distinguished from a noncooperative game primarily by its focus on what groups of players can achieve rather than on what players can do and by the fact that it does not consider the details of how groups of players function internally.

In this thesis the focus lies on coalitional games with transferable payoffs. Each game consists of

- a finite set of players $N$,
- a function $\vartheta$ that associates with every nonempty subset $S$ of $N$ a real number $\vartheta(S)$, which determines the "worth" of $S$.

There exists several solution concepts, where the main goal is to achieve a (set of) payoff vectors that the group can jointly achieve. However, the institutional process of getting there via contracts, threats, etc. is left open in coalitional games.

B.4.3 Continuous Q-learning

In distinction to common approaches with discrete actions sets, an algorithm which allows the utilization of the whole action-set interval instead of predefined discrete actions is introduced [156]. In order to generate the Q-value of an optimal strategy for a decision variable the clearing results of the reserve capacity auction are used.

The action set interval utilization by the algorithm operates as follows:

1. The action set values have to be ordered monotonically.
2. The maximal corresponding Q-value to each decision variable has to be evaluated.
3. The nearest upper/lower action with the corresponding highest (second-best) Q-value has to be determined.
The nearest neighboring action with the highest Q-values of decision variable $i$ and agent $j$, $Q_{a_H}^{i,j,k}$ and $Q_{a_L}^{i,j,k}$ serves to calculate the correction factors $\delta_H^{i,j,k}$ and $\delta_L^{i,j,k}$:

\[
\delta_H^{i,j,k} = \frac{1}{2 + \left[ \frac{Q_{a_H}^{i,j,k} - Q_{a_H}^{i,j,k}}{Q_{a_H}^{i,j,k}} \right]^2}, \quad (B.134)
\]

\[
\delta_L^{i,j,k} = \frac{1}{2 + \left[ \frac{Q_{a_L}^{i,j,k} - Q_{a_L}^{i,j,k}}{Q_{a_L}^{i,j,k}} \right]^2}, \quad (B.135)
\]

with $Q_{a}^{i,j,k}$ as the currently maximum Q-value of decision variable $i$ and agent $j$ in learning round $k$. $Q_{a_H, a_L}^{i,j,k}$ represents the Q-value of decision variable $i$ and agent $j$ in the learning round where the highest Q-value of the nearest neighboring action has been achieved. The resulting action for decision variable $i$ of agent $j$ in the exploitation phase of the algorithm is determined by,

\[
a_i = a_{\text{Max}} + \delta_H^{i,j,k}(a_H - a_{\text{Max}}) + \delta_L^{i,j,k}(a_L - a_{\text{Max}}), \quad (B.136)
\]

where $a_{\text{Max}}$ is the action corresponding to the currently highest Q-value.

Even though the agent is continuously utilizing the action space around the currently optimal Q-value, an exploration part is kept which chooses with a probability $\epsilon$ a random predefined discrete action in the action set. This reduces the chance to get stuck in a local extremum.

Similar to the discrete action set Q-learning algorithm the Q-value is a mapping of the reward gained from a specific action. The rule for the update process in case of exploration is,

\[
Q_{a}^{i,j,k+1} - Q_{a}^{i,j,k} = \alpha(r_{a}^{i,j,k+1} - Q_{a}^{i,j,k}), \quad (B.137)
\]

in case of exploitation, $Q_{a}^{i,j,k}$ is determined by:

\[
Q_{a}^{i,j,k} = \frac{Q_{a}^{i,j,k} + \delta_H^{i,j,k} Q_{a_H}^{i,j,k} + \delta_L^{i,j,k} Q_{a_L}^{i,j,k}}{1 + \delta_H^{i,j,k} + \delta_L^{i,j,k}},
\]

where $a$ refers to the action chosen/calculated, $r_a$ to the resulting (weighted) reward and $k$ to the learning round. $\alpha$ represents the learning parameter.
Bibliography


