The Impact of the Oil Price on EU Energy Prices

STUDY

2014
Abstract

Oil prices have increased considerably over the past years at global level, while natural gas and other energy prices have seen differing developments in each world region. The present report examines the level of impact of high oil prices on European energy prices and analyses the underlying mechanisms. Policy options to reduce this impact are discussed.
CONTENTS

LIST OF ABBREVIATIONS 6
LIST OF TABLES 10
LIST OF BOXES 10
LIST OF FIGURES 11
EXECUTIVE SUMMARY 16
1. OUTLINE OF THE STUDY 21
   1.1. Background 21
   1.2. Aim and scope 22
   1.3. Methodology and data sources 22
   1.4. Structure 23
2. WHOLESALE PRICE TRENDS AND PRICING MECHANISMS 25
   2.1. Long-term trends 26
       2.1.1. Energy commodities 26
       2.1.2. Non-energy commodities 28
       2.1.3. Future projections of long-term trends 30
   2.2. Crude oil 30
   2.3. Natural gas 33
       2.3.1. Introduction 33
       2.3.2. Price trends 34
       2.3.3. Market fundamentals 36
       2.3.4. Price formation mechanisms 38
       2.3.5. Regional differences in EU 53
       2.3.6. Impact of oil price on natural gas prices 60
   2.4. Steam coal 62
       2.4.1. Introduction 62
       2.4.2. Price trends 63
       2.4.3. Market fundamentals 65
       2.4.4. Price formation mechanisms 66
       2.4.5. Regional differences in the EU 76
       2.4.6. Impact of oil price on coal prices 80
   2.5. Electricity 81
       2.5.1. Introduction 81
       2.5.2. Price trends 82
       2.5.3. Market fundamentals 84
Policy Department A: Economic and Scientific Policy

2.5.4. Price formation mechanisms 86
2.5.5. Regional differences in the EU 96
2.5.6. Impact of oil price on electricity prices 99

2.6. Oil products 101
2.6.1. Introduction 101
2.6.2. Price trends 101
2.6.3. Market fundamentals 102
2.6.4. Price formation mechanisms 105
2.6.5. Regional differences in the EU 105
2.6.6. Impact of oil price on oil products prices 106

2.7. Conclusions 107

3. RETAIL PRICE TRENDS AND PRICING MECHANISMS 108

3.1. The European retail energy market 108
3.1.1. Introduction 108
3.1.2. Market fundamentals 110
3.1.3. Electricity retail markets: recent price trends 113
3.1.4. Gas retail markets: recent price trends 116

3.2. Energy bills: main price components and drivers 119
3.2.1. Decomposition of electricity retail prices 120
3.2.2. Decomposition of gas retail prices 123
3.2.3. Analysis of price components 126
3.2.4. National structures of retail electricity and gas prices 135

3.3. Conclusions 140

4. FACTORS INFLUENCING THE OIL PRICE IMPACT 141

4.1. Market factors 142
4.1.1. LNG 142
4.1.2. The impact of US shale gas 143

4.2. Regulatory and political factors 146
4.2.1. The impact of price controls 146
4.2.2. The impact of gas price de-indexation 146

4.3. Other factors 148
4.4. Conclusion 149

5. EVALUATION OF POLICY OPTIONS 151

5.1. Completing the Internal Market to decouple gas and oil prices in Europe 152
5.1.1. The role of infrastructure in enabling wholesale markets 152
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACCC</td>
<td>Australian Competition and Consumer Commission</td>
</tr>
<tr>
<td>ACER</td>
<td>Agency for the Cooperation of Energy Regulators</td>
</tr>
<tr>
<td>ARA</td>
<td>Amsterdam Rotterdam Antwerp</td>
</tr>
<tr>
<td>AU</td>
<td>Australia</td>
</tr>
<tr>
<td>bbl</td>
<td>barrel</td>
</tr>
<tr>
<td>bcf</td>
<td>Billion cubic feet (used in the USA; 1 bcf = 0.283 bcm)</td>
</tr>
<tr>
<td>bcm</td>
<td>Billion cubic meter</td>
</tr>
<tr>
<td>btu</td>
<td>British thermal unit (a traditional unit of energy equal to about 1055 Joule)</td>
</tr>
<tr>
<td>BDEW</td>
<td>Federal Association of the Energy and Water Industry (Germany)</td>
</tr>
<tr>
<td>BDI</td>
<td>Baltic Dry Index</td>
</tr>
<tr>
<td>BE</td>
<td>Belgium</td>
</tr>
<tr>
<td>BEH</td>
<td>Bulgarian Energy Holding</td>
</tr>
<tr>
<td>BG</td>
<td>Bulgaria</td>
</tr>
<tr>
<td>BGR</td>
<td>German Federal Institute for Geosciences and Natural Resources (Bundesanstalt für Geowissenschaften und Rohstoffe)</td>
</tr>
<tr>
<td>CA</td>
<td>Canada</td>
</tr>
<tr>
<td>CAPEX</td>
<td>Capital Expenditure</td>
</tr>
<tr>
<td>CCL</td>
<td>UK Climate Change Levy</td>
</tr>
<tr>
<td>CDG</td>
<td>Single Balancing Point (Spain)</td>
</tr>
<tr>
<td>CEF</td>
<td>Connecting Europe Facility</td>
</tr>
<tr>
<td>CEGH</td>
<td>Central European Gas Hub (Austria)</td>
</tr>
<tr>
<td>CHP</td>
<td>Combined Heat and Power</td>
</tr>
<tr>
<td>CIF</td>
<td>Cost Insurance Freight</td>
</tr>
<tr>
<td>CNE</td>
<td>Comision National de Energía (Spain)</td>
</tr>
<tr>
<td>CNG</td>
<td>Compressed natural gas</td>
</tr>
<tr>
<td>CO</td>
<td>Colombia</td>
</tr>
<tr>
<td>CPI</td>
<td>Consumer Price Index</td>
</tr>
</tbody>
</table>
Impact of the Oil Price on EU Energy Prices

**CY**  Cyprus

**CZ**  Czech Republic

**d**  day

**DE**  Germany

**EC**  European Coimmission

**EDF**  Electricité de France

**EE**  Energy Efficiency

**EED**  Energy Efficiency Directive

**EEX**  European Energy Exchange

**EIA**  Energy Information Administration

**EMIR**  European Market Infrastructure Regulation

**EMV**  Energy Market Authority (Finland)

**EPEX**  European Power Exchange

**ES**  Spain

**ETS**  Emission Trading System

**EU**  European Union

**EU15**  Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, Luxembourg, Netherlands, Portugal, Spain, Sweden, United Kingdom

**EU-27**  All EU Member States up to 30 June 2013

**EUA**  EU Allowance

**FERC**  Federal Energy Regulatory Commission

**FI**  Finland

**FOB**  Free On Board (buyer pays for transportation of goods)

**FR**  France

**FSU**  Former Soviet Union

**FTA**  Free trade agreement

**FTT**  Financial Transaction Tax

**GDP**  Gross domestic product

**GOG**  Gas-On-Gas (competition)
**GPL**  Gaspool (Germany)  
**GWh**  Gigawatt hour  
**HCPI**  Harmonised Consumer Price Index  
**HFO**  Heavy Fuel Oil  
**hl**  hectolitre  
**HU**  Hungary  
**ID**  Indonesia  
**IEA**  International Energy Agency  
**IGU**  International Gas Union  
**IT**  Italy  
**kWh**  Kilowatt hour  
**lb**  Pound  
**LNG**  Liquefied Natural Gas  
**LT**  Lithuania  
**LTC**  long-term contract  
**MMBtu**  One million btu (1 MMBtu = 1,055 Megajoule)  
**MS**  Member State of the EU  
**MWh**  Megawatt hour  
**NBP**  National Balancing Point  
**NCG**  Net Connect Germany (Germany)  
**NEK**  National Electricity Company (Bulgaria)  
**NG**  Natural Gas  
**NGPA**  US Natural Gas Policy Act  
**NL**  The Netherlands  
**NYMEX**  New York Mercantile Exchange  
**OECD**  Organisation for Economic Co-operation and Development  
**OPEX**  Operational Expenditure  
**OTC**  Over-the-counter  
**PCI**  Project of Common Interest  
**PEG**  Point d'Échange de Gaz (France)
<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>PEP</strong></td>
<td>Pan European Power Index</td>
</tr>
<tr>
<td><strong>PGNiG</strong></td>
<td>Polish Oil and Gas Company</td>
</tr>
<tr>
<td><strong>PL</strong></td>
<td>Poland</td>
</tr>
<tr>
<td><strong>PRB</strong></td>
<td>Powder River Basin</td>
</tr>
<tr>
<td><strong>PSV</strong></td>
<td>Punto di Scambio Virtuale (Italy)</td>
</tr>
<tr>
<td><strong>RED</strong></td>
<td>Renewable Energy Directive</td>
</tr>
<tr>
<td><strong>REMIT</strong></td>
<td>Regulation on Energy Market Integrity and Transparency</td>
</tr>
<tr>
<td><strong>RES</strong></td>
<td>Renewable Energy Sources</td>
</tr>
<tr>
<td><strong>RU</strong></td>
<td>Russia</td>
</tr>
<tr>
<td><strong>t</strong></td>
<td>Ton</td>
</tr>
<tr>
<td><strong>tcm</strong></td>
<td>Trillion cubic meter</td>
</tr>
<tr>
<td><strong>TAP</strong></td>
<td>Trans Adriatic Pipeline</td>
</tr>
<tr>
<td><strong>tce</strong></td>
<td>Ton of coal equivalent</td>
</tr>
<tr>
<td><strong>TEN</strong></td>
<td>Trans-European Networks</td>
</tr>
<tr>
<td><strong>TFF</strong></td>
<td>Title Transfer Facility (Netherlands)</td>
</tr>
<tr>
<td><strong>TJ</strong></td>
<td>Terajoule</td>
</tr>
<tr>
<td><strong>TSC</strong></td>
<td>Taxes and Social Contributions</td>
</tr>
<tr>
<td><strong>TUR</strong></td>
<td>Tariff of last resort (tarifa de último recurso)</td>
</tr>
<tr>
<td><strong>UA</strong></td>
<td>Ukraine</td>
</tr>
<tr>
<td><strong>UK</strong></td>
<td>United Kingdom</td>
</tr>
<tr>
<td><strong>US</strong></td>
<td>United States of America</td>
</tr>
<tr>
<td><strong>USA</strong></td>
<td>United States of America</td>
</tr>
<tr>
<td><strong>VAT</strong></td>
<td>Value Added Tax</td>
</tr>
<tr>
<td><strong>WTI</strong></td>
<td>West Texas Intermediate (grade of crude oil used as a benchmark in oil pricing)</td>
</tr>
<tr>
<td><strong>ZA</strong></td>
<td>South Africa</td>
</tr>
<tr>
<td><strong>ZEE</strong></td>
<td>Zeebrugge Platform (Belgium)</td>
</tr>
</tbody>
</table>
LIST OF TABLES

<table>
<thead>
<tr>
<th>Table</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Table 1</td>
<td>Physical hubs vs. virtual trading points</td>
<td>47</td>
</tr>
<tr>
<td>Table 2</td>
<td>Gas hubs in the EU: localisation and churn rates (2011 data)</td>
<td>48</td>
</tr>
<tr>
<td>Table 3</td>
<td>Coal futures volumes traded at EEX starting in 2006</td>
<td>67</td>
</tr>
<tr>
<td>Table 4</td>
<td>Cost structure of coal (2006/07) CIF ARA (US$ per ton)</td>
<td>68</td>
</tr>
<tr>
<td>Table 5</td>
<td>EU Member States regulated tariffs for domestic electricity and gas consumers</td>
<td>112</td>
</tr>
<tr>
<td>Table 6</td>
<td>Individual price components as a share of the domestic electricity retail prices for selected Member States</td>
<td>136</td>
</tr>
<tr>
<td>Table 7</td>
<td>Individual price components as a share of the industry electricity retail prices for selected Member States</td>
<td>137</td>
</tr>
<tr>
<td>Table 8</td>
<td>Individual price components as a share of the domestic gas retail prices for selected Member States</td>
<td>139</td>
</tr>
<tr>
<td>Table 9</td>
<td>Mechanisms linking electricity and gas prices to oil prices</td>
<td>142</td>
</tr>
<tr>
<td>Table 10</td>
<td>Flexibility of conventional power generation technologies</td>
<td>166</td>
</tr>
<tr>
<td>Table 11</td>
<td>Remaining technically recoverable natural gas resources by type and region, end 2011 (in tcm)</td>
<td>187</td>
</tr>
<tr>
<td>Table 12</td>
<td>Fuel consumption of a capesize bulk carrier</td>
<td>197</td>
</tr>
<tr>
<td>Table 13</td>
<td>Fuel cost of a typical transportation trip from USA and Colombia, 2011</td>
<td>197</td>
</tr>
<tr>
<td>Table 14</td>
<td>TUR in effect, data from August 2013</td>
<td>223</td>
</tr>
</tbody>
</table>

LIST OF BOXES

<table>
<thead>
<tr>
<th>Box</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>Box 1</td>
<td>The Italian retail electricity prices for domestic consumers</td>
<td>120</td>
</tr>
<tr>
<td>Box 2</td>
<td>Lithuanian dependency on foreign imports</td>
<td>121</td>
</tr>
<tr>
<td>Box 3</td>
<td>German retail electricity price tax component</td>
<td>123</td>
</tr>
<tr>
<td>Box 4</td>
<td>France regulated domestic gas tariff</td>
<td>124</td>
</tr>
<tr>
<td>Box 5</td>
<td>Hungarian natural gas pricing mechanism</td>
<td>125</td>
</tr>
<tr>
<td>Box 6</td>
<td>The Gazprom case</td>
<td>154</td>
</tr>
<tr>
<td>Box 7</td>
<td>Textbox: “Regionalisation” of national energy markets</td>
<td>198</td>
</tr>
</tbody>
</table>
## LIST OF FIGURES

<table>
<thead>
<tr>
<th>Figure</th>
<th>Description</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Flow chart of analysis</td>
<td>24</td>
</tr>
<tr>
<td>2</td>
<td>Long-term price trends of crude oil, steam coal, uranium and NG</td>
<td>27</td>
</tr>
<tr>
<td>3</td>
<td>Price indices for various commodities</td>
<td>29</td>
</tr>
<tr>
<td>4</td>
<td>Correlations between daily price changes of crude oil futures and other commodities in the USA</td>
<td>29</td>
</tr>
<tr>
<td>5</td>
<td>Crude oil spot prices and import costs for Europe and the USA</td>
<td>31</td>
</tr>
<tr>
<td>6</td>
<td>Spread between European and US crude oil spot and import prices</td>
<td>32</td>
</tr>
<tr>
<td>7</td>
<td>Average crude oil import costs into selected European countries and the USA</td>
<td>32</td>
</tr>
<tr>
<td>8</td>
<td>Crude oil import cost differences between selected European countries and IEA Europe average</td>
<td>33</td>
</tr>
<tr>
<td>9</td>
<td>Natural gas import and spot prices in Europe</td>
<td>34</td>
</tr>
<tr>
<td>10</td>
<td>Natural gas price correlation to Brent crude oil in Europe</td>
<td>35</td>
</tr>
<tr>
<td>11</td>
<td>Natural gas import and spot prices in Europe and the USA</td>
<td>36</td>
</tr>
<tr>
<td>12</td>
<td>2012 World gas production by region (in bcm)</td>
<td>37</td>
</tr>
<tr>
<td>13</td>
<td>2011 World sectorial gas demand by region (in bcm)</td>
<td>38</td>
</tr>
<tr>
<td>14</td>
<td>Natural gas price formation in Europe (2012 data)</td>
<td>39</td>
</tr>
<tr>
<td>15</td>
<td>Indexation pattern under long-term gas contracts in the EU (based on 2004 data)</td>
<td>41</td>
</tr>
<tr>
<td>16</td>
<td>Indexation pattern under long-term gas contracts according to producing regions (based on 2004 data)</td>
<td>42</td>
</tr>
<tr>
<td>17</td>
<td>Indexation pattern under long-term gas contracts according to the importing regions (based on 2004 data)</td>
<td>44</td>
</tr>
<tr>
<td>18</td>
<td>World electricity generation – 1973 vs. 2011</td>
<td>45</td>
</tr>
<tr>
<td>19</td>
<td>US natural gas annual consumption during the ‘Gas Bubble’ period</td>
<td>50</td>
</tr>
<tr>
<td>20</td>
<td>Natural gas market centres and hubs in relation to major natural gas transportation corridors, USA, 2009</td>
<td>51</td>
</tr>
<tr>
<td>21</td>
<td>Natural gas and crude oil prices in the USA (1997-2013)</td>
<td>52</td>
</tr>
<tr>
<td>22</td>
<td>Wholesale day-ahead NG prices at European hubs</td>
<td>54</td>
</tr>
<tr>
<td>23</td>
<td>Natural gas import prices into European countries</td>
<td>55</td>
</tr>
<tr>
<td>24</td>
<td>Price difference of natural gas between individual countries and EU Member State average</td>
<td>55</td>
</tr>
<tr>
<td>25</td>
<td>Price formation mechanisms in Europe (2005 vs. 2012)</td>
<td>56</td>
</tr>
<tr>
<td>26</td>
<td>Share of Russian gas in overall gas consumption (2012 data)</td>
<td>58</td>
</tr>
<tr>
<td>27</td>
<td>Comparison of EU wholesale gas prices (Price in €/MWh)</td>
<td>59</td>
</tr>
<tr>
<td>28</td>
<td>Development of the oil price and EUR/USD exchange rate (2000-2013)</td>
<td>62</td>
</tr>
</tbody>
</table>
Figure 29: Steam coal import costs into Europe and the USA
Figure 30: Correlation of steam coal and natural gas prices in Europe, USA and Germany
Figure 31: Steam coal import cost correlation to Brent crude oil for EU and Germany
Figure 32: EU hard coal production
Figure 33: Hard coal gross inland consumption
Figure 34: Coal supply FOB cash cost curve for internationally traded steam coal in 2010/2011
Figure 35: Coal supply FOB marginal cost curve by country in 2006
Figure 36: Comparison of future coal price projections with actual coal prices
Figure 37: Global bulk freight index BDI
Figure 38: Development of hard coal (spot) freight prices (Capesize) between 2002 and 2013 to the ARA ports (in US$/t)
Figure 39: Fuel costs for the shipping of one ton of coal from Newport News, USA, or from Cienaga, Colombia, to Rotterdam
Figure 40: Steam coal import prices in European countries
Figure 41: Difference between steam coal import costs into selected countries and EU Member State average
Figure 42: Coal imports by country of origin for 10 Member States
Figure 43: Poland – Electricity generation by type of fuel (2011)
Figure 44: Electricity prices in Europe
Figure 45: Electricity prices in the USA
Figure 46: Development of gross electricity generation by primary energy source in the EU-27 in TWh
Figure 47: Electricity demand in the EU-27 between 2003 and 2012 in GWh
Figure 48: Structure of electricity wholesale markets
Figure 49: EEX spot traded electricity volumes compared to total consumption in Germany and Austria
Figure 50: Market share of the largest generator in the electricity market in % of total generation in 2011
Figure 51: Merit order supply curve (example)
Figure 52: Exemplary illustration of a merit order curve for Germany in 2012; spot market prices of 4 September 2012
Figure 53: Projected merit order curve for Germany in 2020
Figure 54: Clean dark and spark spreads for Germany (DE) and the UK
Figure 55: Average gas-fired power plant efficiencies in Germany, the Netherlands and the UK
Figure 56: Merit order curve for the Nord Pool exchange in 2009
Figure 57: Capacity mechanisms in Europe
Figure 58: Electricity generation of 10 selected EU Member States by primary energy source in 2010

Figure 59: Baseload electricity prices in European countries

Figure 60: Price difference between baseload electricity and PEP index for selected European countries

Figure 61: Oil product spot prices in northwest Europe

Figure 62: Oil product spot prices in the USA

Figure 63: Development of oil product output from European refineries

Figure 64: Crude oil and oil product trade

Figure 65: Oil product output from European refineries in 2011

Figure 66: Development of refinery capacity and utilization rates in the USA, Europe and the rest of the world

Figure 67: Refining margins for simple and complex refineries and various types of crude oil

Figure 68: Correlation between crude oil price and selected oil products

Figure 69: Overview on most important price formation mechanisms of energy commodities

Figure 70: Household electricity prices including all taxes for 2nd semester 2012

Figure 71: Industry electricity prices including all taxes for 2nd semester 2012

Figure 72: Residential user electricity prices (EU-15 average) versus wholesale electricity prices

Figure 73: Retail gas prices for domestic consumers

Figure 74: Retail gas prices for industrial consumers

Figure 75: Residential user gas prices (EU-15 average) versus wholesale electricity prices

Figure 76: Overview of the main drivers and price components of retail electricity prices in the EU

Figure 77: Household electricity price breakdown for the year 2012

Figure 78: Key drivers and price components for retail gas prices

Figure 79: Household consumer retail gas price breakdown year 2012

Figure 80: Comparison of electricity retail prices versus wholesale electricity prices for Finland

Figure 81: Comparison of electricity retail prices versus wholesale electricity prices in Italy

Figure 82: Comparison of electricity retail prices versus wholesale electricity prices for France

Figure 83: Comparison of gas retail prices versus wholesale electricity prices for the UK

Figure 84: Price of electricity with different contract types for Finland
<p>| Figure 85: Spread between TUR and free-market electricity prices | 131 |
| Figure 86: Italy comparison of oil price and retail electricity price for the period 2001-2012 | 132 |
| Figure 87: Evolution of the different price components for industry in Germany | 134 |
| Figure 88: Evolution of the different price components for households in Germany | 134 |
| Figure 89: US dry gas production | 145 |
| Figure 90: US net gas imports | 145 |
| Figure 91: European oil-indexed prices vs. NBP prices | 147 |
| Figure 92: Interconnections, reverse flows in the EU-27 gas system. | 153 |
| Figure 93: Evolution of environmental taxation revenues in the EU-27 as percentage of Taxes and Social Contributions (TSC) | 156 |
| Figure 94: Energy taxes, GDP and final energy consumption, in the EU-27, (index 1995=100) | 157 |
| Figure 95: 2012 World gas production by region (in bcm) | 186 |
| Figure 96: 2011 World sectorial gas demand by region (in bcm) | 188 |
| Figure 97: EU imports of natural gas in 2011 and their share in total consumption compared to oil | 189 |
| Figure 98: Total global coal consumption and production | 192 |
| Figure 99: Global hard coal production 2011 by producing country | 193 |
| Figure 100: Development of hard coal net imports and net exports by country | 194 |
| Figure 101: EU hard coal production | 194 |
| Figure 102: Hard coal gross inland consumption | 195 |
| Figure 103: Hard coal imports into the EU-27 by country of origin, 2012 | 195 |
| Figure 104: Main trade flows in seaborne hard coal trade, 2012 | 196 |
| Figure 105: Steam coal market 2012 | 196 |
| Figure 106: Map of 10 Selected Member States (in blue in the map) | 199 |
| Figure 107: Evolution of decomposition of electricity prices for domestic consumers in Bulgaria (Band DC) industrial consumer (Band IC) | 200 |
| Figure 108: Evolution of decomposition of retail gas prices for domestic consumers in Bulgaria (Band D2) industrial consumer (Band I3) | 201 |
| Figure 109: Development of the price of electricity by individual component for Finland | 202 |
| Figure 110: Evolution of French tariffs (taxes excluded) for different consumer categories in euros at constant prices for the period 1996-2012 | 204 |
| Figure 111: Electricity price decomposition for the French retail market by type of consumer, situation on March 31st 2013 | 205 |
| Figure 112: Price decomposition of the regulated tariff offered by GDF Suez year 2012 | 206 |</p>
<table>
<thead>
<tr>
<th>Figure</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>113</td>
<td>Germany evolution of gas and electricity price index in comparison with oil prices for the period 2000-2012</td>
</tr>
<tr>
<td>114</td>
<td>Electricity retail price composition domestic consumers for Germany on April 1 2012</td>
</tr>
<tr>
<td>115</td>
<td>Electricity retail price composition for industrial customers for Germany on 1 April 2012</td>
</tr>
<tr>
<td>116</td>
<td>Retail gas price composition for households at default supply service – April 2012</td>
</tr>
<tr>
<td>117</td>
<td>Average retail gas price for industrial consumers at switch of supplier rates – April 2012</td>
</tr>
<tr>
<td>118</td>
<td>Hungarian gas market price changes 2011</td>
</tr>
<tr>
<td>119</td>
<td>Hungarian electricity prices by components concerning a model household consumer (2400 kWh/year consumption in general tariff)</td>
</tr>
<tr>
<td>120</td>
<td>Evolution of retail electricity price by component for a ‘model’ household consumer</td>
</tr>
<tr>
<td>121</td>
<td>Evolution of the average natural gas price for households (HUF/m3) in Hungary</td>
</tr>
<tr>
<td>122</td>
<td>Italian percentage composition of the electricity price for a household consumer – 1st quarter 2013</td>
</tr>
<tr>
<td>123</td>
<td>Detailed breakdown of gas prices for average household consumer – Italy</td>
</tr>
<tr>
<td>124</td>
<td>Lithuanian electricity retail price structure</td>
</tr>
<tr>
<td>125</td>
<td>Evolution of Lithuanian electricity prices by component</td>
</tr>
<tr>
<td>126</td>
<td>Evolution and forecast of energy mix for Poland</td>
</tr>
<tr>
<td>127</td>
<td>Evolution of decomposition of electricity prices for domestic consumers in Poland (Band DC) and industrial consumers (Band IC)</td>
</tr>
<tr>
<td>128</td>
<td>Estimated average value of each price component for retail electricity prices – Spain</td>
</tr>
<tr>
<td>129</td>
<td>Evolution of decomposition of electricity prices for domestic consumers in Spain (Band DC) and industrial consumers (Band IC)</td>
</tr>
<tr>
<td>130</td>
<td>Evolution of the fixed component of retail gas prices – Spain 2002-2011</td>
</tr>
<tr>
<td>131</td>
<td>Evolution of the variable component of retail gas prices – Spain 2002-2011</td>
</tr>
<tr>
<td>132</td>
<td>Comparison of fuel price indexes for different consumer categories – UK</td>
</tr>
<tr>
<td>133</td>
<td>Price components of electricity bills in the UK in 2012</td>
</tr>
<tr>
<td>134</td>
<td>Price components of gas bills in the UK in 2012</td>
</tr>
</tbody>
</table>
EXECUTIVE SUMMARY

Background

EU energy policy aims at providing a secure, competitive, and sustainable energy to citizens and businesses. The European Commission, the European Parliament, and the European Council have recently expressed their concerns about high energy prices in Europe, while emphasizing that both affordability and sustainability are equally crucial. The European Council has announced that the European Commission will present an analysis of the composition and drivers of energy prices and costs in Member States in early 2014.

The significant price difference for natural gas between the USA and Europe is a relevant trigger of the political discussion. Another important aspect relates to the level of the international oil price and how it may influence energy prices in the EU as well as to the potential consequences thereof, including the competitiveness of the European economy.

Aim and Scope

The objective of this study is to evaluate the impact of the oil price on energy prices in the EU. For this purpose, the study looks at price developments of natural gas and coal as well as the secondary energies electricity and oil products.

The study takes into account both wholesale energy prices and retail energy prices paid by industries as well as by households. Price formation mechanisms of the different energies at wholesale level are analysed. On the retail level, consumer price structures are analysed covering all price components, discussing both regulated and unregulated consumer tariffs.

The European Union is analysed as a whole; additionally, regional energy sub-markets within the EU are showcased by analysing 10 selected Member States. The study also provides a comparison with the US energy markets, notably in the gas sector.

Wholesale price trends and pricing mechanisms

How have energy prices developed in the past years?

Looking back over a longer period, global oil prices and European natural gas prices are trending significantly higher today compared to the 1990s. On the other hand, coal prices show only a rather slight increase over that period, while they were much higher in the 1980s. All three energies as well as electricity display a sharp price peak in 2008, but apart from that, generally differ in volatility. In spite of continued economic difficulties globally since 2008, the oil price quickly increased again after a steep decline in late 2008, and continues to trade in the 100 US-$ per barrel range since early 2011.

Crude oil price differences between Europe (Brent) and the USA (WTI – West Texas Intermediate) are due to infrastructural and export constraints in the USA, and may vanish in the foreseeable future. Gas prices are roughly a factor of two lower in the USA than in Europe. After a period of price parity during 2009 and the beginning of 2010, gas spot prices between the US and the UK (the most liquid European gas hub) strongly decoupled.

2 European Council - DOC/13/4 22/05/2013
3 US prices have been less than half of European prices for most of the time since 2011
Spot prices in Europe in general are lower than prices of long-term oil-indexed gas contracts, but volatility of spot prices is higher, and price peaks surpass import gas prices, which are a proxy of oil-indexed prices.

Non-energy commodities including minerals and agricultural products show similar price developments between 2008 and 2013, indicating that global economic development may be the fundamental cause of these partly parallel developments rather than the oil price.

**What are the correlations of energy prices to the oil price?**

Natural gas, coal, electricity, and oil product prices more or less clearly move parallel to the oil price. Correlation of the oil price with gas prices is strong (both for import prices and for spot prices), slightly weaker with steam coal, and very strong for oil products, whereas electricity only correlates moderately with the oil price. However, in contrast to the oil price, steam coal prices have been slowly declining since late 2011 and correlation has gone down. Correlation effects are not instantaneous, but follow the oil price with a time lag of 3-6 months for natural gas and steam coal, and 3-4 months for electricity. No time lag is observed for oil products.

**What are the pricing mechanisms currently in place for energy commodities? Are there regional differences?**

Pricing mechanisms vary greatly between commodities.

For natural gas, oil indexation is the "traditional" pricing mechanism in Europe with the price of gas being pegged to the price of oil or of oil products. Gas-on-gas competition (also known as hub-based pricing) has become the dominating pricing mechanism in the UK and is gaining ground in Central and North-Western Europe. However, importing Member States pay a higher price for their gas supplies the closer they are to Russia (so called Opera pricing) because of reduced bargaining power for lack of alternative supply routes. Oil indexation in gas contracts is no longer relevant in the USA, where spot pricing prevails.

Steam coal is traded globally. However, compared to oil, coal transport is more costly, and markets are less liquid and less transparent. Coal prices are built on the marginal FOB (free on board) cost curve of mines globally producing for export markets. Steam coal prices are expected to remain constant or decrease slightly in the near future because of global overcapacities, but are prone to increase again in the mid-term as market prices are currently below marginal costs for some major suppliers. Regional price differences within Europe are small, and based on transport costs between Member States. Data availability is patchy and the understanding of coal markets in the public domain is rather limited.

Electricity prices vary considerably in Europe. As a result of merit order pricing mechanisms, determining in any given time slot which power plants are operational based on their marginal electricity production costs, national electricity demands and generation mixes lead to different prices. Market integration into a single electricity market in Europe has not yet been fully achieved, while regional price convergence is increasing and already high in some regions.

The prices of oil products including gasoline, diesel, kerosene, fuel oil etc. are strongly correlated to the crude oil price because of the very high share of crude oil in their production. Regional differences are predominantly caused by transport costs and the regional balance of production and demand.
How important is the oil price compared to other price drivers for the energy commodities considered?

While, obviously, long-term natural gas contracts indexed to the oil price or to prices of oil products are directly influenced by the oil price, for gas-on-gas competition, it does not have a direct impact. In Europe, the share of oil-indexed contracts is diminishing, from 75% in 2005 to 50% in 2012. The oil price is a particularly important price driver in Central and Eastern European countries, while it has hardly any direct impact in the UK and the Netherlands. Indirect impacts of the oil price are harder to grasp and quantify.

Potential indirect impacts include substitution potentials, horizontal integration of oil and gas companies, physical links between oil and gas production, oil products as transportation fuels for liquefied natural gas (LNG) shipping, and correlation between oil price and exchange rates.

For steam coal, fuel costs based on oil products contribute to coal extraction and inland transportation costs, and thus to FOB costs. While detailed analyses are lacking, a rough estimate shows that the impact is limited, yet visible. Other cost elements such as labour, machinery and operation and maintenance costs are further important elements in significantly increasing FOB costs over the past few years; exchange rate developments play a role as well. Indirect impacts of the oil price on coal prices include the substitution of steam coal by gas in electricity generation. The function of the oil price as an indicator of economic development and market psychology are also relevant.

On electricity prices, the oil price and the prices of oil products have little direct impact in Europe, except for Cyprus and Malta which highly depend on oil for their electricity production. The most important indirect oil price impact is its influence on the natural gas price, reinforced by the fact that gas-fired power plants are often price setting. The limited impact of oil price on coal provides for only a small indirect impact on electricity prices. Varying national electricity generation mixes lead to significantly differing impacts for each country.

It is important to emphasise that the fundamental drivers of natural gas, coal, and electricity demand are frequently the same that also impact oil consumption.

Retail price trends and drivers

How do the wholesale price trends and pricing mechanisms connect to the prices paid by household and industrial consumers?

The European retail energy market is characterised by large disparities and differences in price level, price setting mechanisms and market models applied. In general, retail prices of electricity and gas are higher for households than for industrial consumers (on average 30% and 18% higher for electricity and gas, respectively, across all Member States compared to medium-size industrial consumers).

Retail tariff structures generally shield consumers from short-term variations in wholesale prices. However, longer-term price trends of wholesale markets are generally passed on to the consumers in liberalised markets. Regulated tariffs still exist in 18 Member States for household and/or industrial consumers of electricity and/or gas. These tend to shield consumers from oil price variations even more than market-based tariffs, at least in the short and medium-term. However, long-term trends will need to be reflected also in regulated tariffs.
What are the main drivers of energy prices paid by consumers and what is the relative importance of the oil price in this respect?

Across the EU it is apparent that electricity price differences are largely driven by the energy mix in each Member State, electricity production costs, and the merit order curve. In the case of retail gas prices, import prices and import dependency appear as the key drivers of price levels.

Energy retail prices have four major price components, namely wholesale energy costs, supplier margins, network charges, and taxes and other charges. The relative share of these components varies significantly depending on the type of consumer. Network charges, taxes, and other charges are regulated by each Member State. They are independent of the supplier, are in general passed on fully to the final consumer, and are independent of the oil price.

On average, the non-regulated price components, most importantly the wholesale energy costs have a share of 40%-60% of the retail prices in the 10 selected Member States. Consequently, any impact of the oil price on wholesale prices only affects 40-60% of the final consumer price (except for value added tax – VAT).

Factors controlling the impact of the oil price

Which factors reduce the impact of the oil price on European energy prices?

Factors potentially reducing the oil price impact include globally increasing LNG markets, increasing US gas production, (potential) US gas exports, (potential) European shale gas production, price controls on retail gas and electricity prices, high network charges and taxes on retail energy, gas price de-indexation, diversification of gas supplies, pass through factors and time lags (for oil indexation contracts), increased use of renewable energy sources, increased energy efficiency and strengthening of the Euro and other European currencies.

Generally, the link between oil and gas prices depends on the overall market conditions for gas internationally, regionally, and domestically. However, when gas market conditions are expected to remain tight, there is little that policy can do to avert price increases.

Which factors reinforce the impact of the oil price on European energy prices?

Factors potentially reinforcing the oil price impact include increased global and/or European demand for gas or reduced global and/or European supply capacity, weakening or elimination of controls on retail gas and electricity prices, lowering of network charges or taxes on retail energy, weakening of the Euro and other European currencies.

Policy options

What is the probability of a full hub-based pricing for natural gas in the EU in the coming years and what would be the impact of this on energy prices?

While the EU might try to accelerate the process of decoupling oil and gas prices, it seems that this objective will not be achieved in a foreseeable future. Despite the fact that one major exporter, Norwegian oil and gas company Statoil, seems to be gradually moving away from oil-indexation in its gas contracts, the majority of the other exporters representing 54% of EU imports seems reluctant to make that move. The completion of a well-functioning, interconnected single gas market could encourage gas producers to engage in the transition to hub-based pricing. Therefore, investments in transport and storage infrastructure are required to foster the development of liquid gas hubs across the EU and should be considered as part of a longer process.
Developing viable alternatives to oil-indexed gas contracts is important. They should rely on a price signal created by markets and reflect the actual situation of natural gas supply and demand. Policy options in this field can particularly target the currently limited competition, and thus improve the bargaining position of gas importers.

**Which changes in taxation are possible and which would be their impacts on energy prices?**

Energy taxation represents an important source of public revenues for national governments all over Europe due to the low price elasticity of energy commodities. Through the existing system of minimum excise duty it is also in principle possible to partly protect consumers from the effect of oil prices shocks, by reducing the level of taxation when prices are too high. However, this should be avoided since shielding consumers from price increases sends the wrong economic signal and prevents end-users from adapting their behaviour.

**How can energy efficiency and renewable energies help protect EU energy prices from high oil prices?**

Energy efficiency and renewable energy sources reduce the demand for fossil energies and thus contribute to reducing fossil energy prices through price elasticity. As renewable energies are rather unaffected by the oil price, they also weaken the impact of oil price on energy prices in their respective area of use. Furthermore, renewable energies help to reduce the economic impacts of high oil prices on the national economies by reducing the reliance on oil imports with related financial outflows.

**What are other relevant policy options?**

For completeness, the following more remote policy options are also discussed in this study: Deploying carbon capture and storage (CCS) can allow coal fired power plants to fulfil greenhouse gas reduction requirements and thus remain in the electricity generation mix longer as a rather oil price independent constituent. Innovative shale gas extraction methods with reduced environmental and health-related risks may contribute to a diversification of European gas supplies. Finally, monitoring US gas production for possible export opportunities and facilitating the potential import of US LNG shipments (e.g. by including energy exports into the potential transatlantic trade pact) may enhance the diversity of European gas supplies.

In conclusion, the set of policy options available for reducing the impact of the oil price on European energy prices is large. Many of these will additionally contribute to other European targets, including increasing security of supply, supporting climate protection, improving the competitive situation of European industry, creating employment, and accelerating sustainable economic growth.
1. OUTLINE OF THE STUDY

1.1. Background
The Treaty on the Functioning of the European Union\(^4\), Article 194 on energy, requires ensuring the functioning of the energy market, ensuring security of energy supply, promoting energy efficiency and energy savings and the development of new and renewable forms of energy, and promoting the interconnection of energy networks while preserving and improving the environment. On this background, EU energy policy aims at providing a secure, competitive and sustainable energy to citizens and businesses\(^5\). The importance of energy affordability for well-being of the European people and for industrial competitiveness is notably highlighted in the European Commission Energy Roadmap 2050\(^6\).

Both the European Parliament in its resolution of 14 March 2013 endorsing the Energy Roadmap 2050\(^7\) and in its resolution of 10 September 2013 welcoming the European Commission Communication on “Making the internal energy market work”\(^8\) and the European Council in its Conclusions of 14-15 March 2013\(^9\) have recently expressed their concerns about high energy prices in Europe and highlighted the need to tackle this challenge so as to guarantee the competitiveness of the European economy. In its Conclusions of 22 May 2013\(^10\), the European Council emphasized that “supply of affordable and sustainable energy to our economies is crucial”, and announced that the European Commission would present an analysis of the composition and drivers of energy prices and costs in Member States before the February 2014 European Council on industrial competitiveness and policy. Energy prices and the relevance of this analysis are also addressed in the upcoming Impact Assessment for a 2030 climate and energy policy framework, which is currently prepared by the European Commission.

Main aspects of the political discussion about increasing energy prices include the level of the international oil price and how it may influence energy prices in the EU on the one hand, and the significant price difference of natural gas between the USA and Europe\(^11\) on the other hand. The resulting consequences and the influence on the competitiveness of the European economy are key concerns.

Oil prices have started to increase in 2004, and have seen a record increase and a historical price peak in 2008, followed by a sharp decline in the financial and economic crisis. However, in spite of continued economic difficulties globally, the oil price quickly increased again and continues to trade in the 100 US-$ per barrel range. While these prices are high compared to historical price levels, projections of future oil prices agree that they are not expected to go down significantly.


\(^8\) European Parliament, Resolution of 10 September 2013 on Making the internal energy market work, A7-0262/2013; Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, Making the internal energy market work, COM(2012) 663 final.

\(^9\) European Council, 14/15 March 2013, Conclusions, EU CO 23/13

\(^10\) European Council, 22 May 2013, Conclusions, EU CO 75/1/13

\(^11\) US prices have been less than half of European prices for most of the time since 2011
1.2. **Aim and scope**

The objective of the study is to evaluate the (potential) impact of oil price on the levels and evolution of energy prices in the EU, and to identify possible policy options to reduce this impact. For this purpose, the study considers primary energy sources, notably natural gas and coal, as well as secondary energies such as electricity and oil products.\(^{12}\)

The study takes into account both wholesale energy prices and retail energy prices paid by industries as well as by households. With this spectrum of the various energy prices paid in the EU, the objective is to assess how the oil price impacts energy prices in the EU.

Pricing mechanisms of the different energies at wholesale level are analysed in order to understand the factors underlying price setting and the role of the oil price in them. On the retail level, consumer price structures are analysed covering all elements including wholesale prices, network charges, taxes and other charges, and supplier margins, also assessing the respective oil price impact.

As for its geographical scope, the study analyses the European Union as a whole and showcasing various regional energy sub-markets by focussing on 10 selected EU Member States. It also provides a comparison with the US energy markets, notably in the gas sector.

1.3. **Methodology and data sources**

The availability of reliable and sufficiently detailed data was a challenge for carrying out these analyses. Many important data sets are either simply inexistent, or very difficult to access, or only available commercially at high prices. Improving on this front by facilitating a harmonized data collection on energy prices across Member States would be a worthwhile objective for the EU in order to improve the basis for scientific work on the issue, and thus develop a better understanding of the underlying mechanisms benefitting stakeholders in industry and policy making.

Data of wholesale energy prices were gathered from different sources, most notably publications of the European Commission, Eurostat, the International Energy Agency, and the US Energy Information Administration. Information from national statistical offices and other types of publications has been used to complement the data.

For retail energy prices, Eurostat has been used, complemented by national sources of data such as energy regulators, statistical offices, and trade associations. For selected Member States (see below) a thorough research was carried out on the websites of energy regulators and national statistical offices to retrieve data providing detailed decomposition of energy prices. Annual reports produced by the national regulators were also analysed, if an English translation was available. When information was not readily available, direct contact was established with representatives of these bodies. Unfortunately, most Member States have adopted a national approach for the classification of consumption bands and consumer categories, which is often incompatible with Eurostat, or not defined in sufficient detail. As a result, in spite of this extensive effort, a comprehensive but not fully harmonised data set could be compiled, and for some Member States best available data were sourced from Eurostat.

---

\(^{12}\) Oil products are useful materials derived from crude oil as it is processed in oil refineries. They are used for a variety of purposes such as transport (e.g. LPG, gasoline, kerosene, diesel, heavy fuel oil/marine bunker fuel etc.), heating and cooking (e.g. kerosene, gasoil, etc.) and power production (e.g. gas oil, fuel oil, etc.) as well as in industrial processes.
Ten EU Member States were selected to showcase various regional energy sub-markets within the EU and to describe different energy market situations across the EU. A set of five criteria was chosen in order to achieve a balanced and representative selection. For more details, please refer to Annex D. For the following 10 Member States more detailed analyses of wholesale markets and of the structure of retail energy bills were made: Bulgaria, Finland, France, Germany, Hungary, Italy, Lithuania, Poland, Spain, and the UK.

The analysis of wholesale and retail pricing mechanisms was based on a broad set of published sources and was complemented by expert interviews. Following a bottom-up approach, all elements of pricing mechanisms were identified from literature and expert interviews, and then analysed for possible mechanisms causing an impact of the oil price on the energy commodities considered. The identified oil price impact was assessed in qualitative terms; a quantitative assessment was beyond the scope of this work.

The evaluation of policy options was based on published sources from the scientific and the policy domains as well as from general media, and was carried out in view of the current political debates in Europe.

For the study, literature sources published before the end of September 2013 have been taken into account for the analysis. Relevant later publications could not be included, but have been checked for consistency with the results achieved.

The authors of this study greatly acknowledge the support and valuable input through bilateral interviews provided by Mr Jean-Marie Chevalier (Université Paris-Dauphine), Mr Albero Clo (University of Bologna), Mr Aad Correlje (Clingendael International Energy Programme), Ms Franziska Holz (Deutsches Institut für Wirtschaftsforschung), Mr Martin Godfred and Mr Giancarlo Scarsi (ACER), Mr Christian Lutz (Gesellschaft für Wirtschaftliche Strukturforschung), Mr Klaus Picard (Mineralölwirtschaftsverband), Mr Lars Schernikau (Ichor Coal) as well as experts present at the CEPS Energy Market Forum on 3 July 2013.

**1.4. Structure**

The study is organised in four main chapters.

Chapter 2 analyses the development of energy wholesale prices at global and European level and covering the USA with the objective to identify if and how prices for the energy commodities natural gas, steam coal, electricity, and oil products correlate with the oil price. This part is descriptive and uses qualitative and quantitative methods to identify correlations.

Renewable energies are not included in this analysis as they are either not traded internationally, notably solar irradiation or wind, or because international bulk trade is comparably small as in the case of bio energy. Renewable energies certainly are impacted by oil price and other energy prices. This is particularly the fact in the manufacturing of renewable energy technologies requiring energy intensive materials such as steel, composite fibre materials or silicon. However, after manufacturing and installation, they only consume renewable energies such as wind or solar irradiation. It should also be noted that the share of conventional energies required in the manufacturing process of renewable technologies has diminished over time with increasing shares of renewable energies in the general energy mix. Renewable energies are substitutes to fossil energies analysed in this study, and thus there is cross-price elasticity of demand between them. The potential role of renewable energies in mitigating oil price impact is addressed in section 5.3.
In a second step in chapter 2, price formation mechanisms are discussed in order to verify whether the correlations found are based on cause and effect relationships with oil, or whether other factors lead to these correlations. The direct and indirect impacts of oil price on wholesale energy prices are assessed here.

**Figure 1: Flow chart of analysis**

Source: Study authors

Chapter 3 analyses consumer prices covering all elements of the price structure including wholesale prices, network charges, taxes and other charges, and supplier margins. Overviews of electricity and natural gas bills paid by private and industrial consumers in the 27 EU Member States are provided in Annex E.

Chapter 4 summarizes the main factors responsible for the translation of high oil prices into high energy prices in Europe and identifies the most significant drivers based on the results of the previous two chapters.

Chapter 5 evaluates the main policy options currently debated to help mitigate a translation of high oil prices into high energy prices.
2. WHOLESALE PRICE TRENDS AND PRICING MECHANISMS

KEY FINDINGS

- Long-term price trends (corrected for inflation) show significantly higher global oil and European natural gas prices today compared to the 1990s, and rather slight increases in coal prices during that period.

- Crude oil prices peaked sharply in 2008 with subsequent decline in the financial crisis, and have now regained similarly high levels. Differences between the higher European (Brent) and the lower US (WTI) oil spot prices are due to infrastructural and legal constraints in the USA, and may vanish in the foreseeable future.

- Price formation mechanisms for natural gas vary greatly across Europe. Oil indexation is the “traditional” pricing mechanism in Europe with the price of gas being pegged to the price of oil or of oil products. Gas-on-gas competition (hub-based pricing) has become the dominating pricing mechanism in the UK and is gaining ground in Central and North-Western Europe. Importing Member States pay a higher price for their gas supplies the closer they are to Russia (Opera pricing).

- Marginal production costs of coal have increased considerably since 2006. It is estimated that roughly around one quarter of this increase may be attributed to oil price increases. Coal prices are expected to decrease slightly in the near future because of global overcapacities, and to increase again mid-term as market prices are currently below marginal costs, which cannot be sustained over longer periods.

- Electricity prices vary considerably in Europe, and in general show a moderate correlation to oil price developments. Through the merit order curve, national electricity mixes lead to different prices. Market integration into a single electricity market in Europe has not yet been fully achieved. The prices of oil and oil products have little direct impact on electricity prices in Europe. The most important indirect impact is that of the oil price on natural gas through oil-indexed contracts, reinforced by the fact that gas-fired power plants are often price setting. The limited impact of oil prices on coal provides for a small indirect impact on electricity prices.

- Oil product prices are strongly related to crude oil prices because of the very high share of feedstock costs in their production.

- In essence, the main factor translating high oil prices into high wholesale gas and electricity prices in Europe is the still dominant practice of indexation of gas prices to oil prices, prevalent in a majority of gas supply contracts in Europe.

- Although both gas and oil share common fundamental price drivers (such as economic development) and their prices often seem to be correlated, in places where oil indexation is basically absent, such as the USA, gas and oil prices are often decoupled, proving that there are no fundamental reasons why gas prices should follow those of oil.

This chapter describes the trends of energy commodity prices in wholesale markets including their correlations to the oil price, and time lags for these correlations. Correlations do not necessarily imply a cause and effect relationship, but simply describe parallel developments.
Therefore, price formation mechanisms are analysed for each energy commodity in order to identify direct and indirect impacts of oil price on each energy commodity. Oil price is taken as an input to this analysis – the oil price formation mechanisms are not included in the present analysis. After discussing long-term trends of wholesale energy prices and crude oil prices, the four energy commodities are analysed in detail in separate sections. Each section starts with an introduction and a subsequent analysis of price trends and price correlations, notably to oil, in order to describe developments. Market fundamentals are presented next, providing the necessary background for the subsequent detailed analysis of price formation mechanisms. Then, regional differences in the EU are analysed on this basis, including an analysis of the underlying causes. Finally, the price developments and correlations found for each energy commodity are combined with the price formation mechanisms in order to assess the impact of the oil price on the respective energy commodity price.

2.1. Long-term trends

This section describes long-term trends of oil, gas, steam coal, electricity, and oil product prices and compares them to price trends of non-energy commodities. It analyses statistical correlations; causes for trends and correlations found will be analysed in later sections of this chapter.

Prices for all energy commodities are monthly or quarterly (steam coal) averaged prices. Where necessary, they were converted into Euro using the average monthly US-$/€ exchange rate as published by (Eurostat 2013a). Additionally, datasets for long-term trends were converted to €\textsubscript{2012} prices. Real term prices have been calculated based on the European Harmonised Consumer Price Index (HCPI) for the years 2013 back to 1996 (Eurostat 2013b) and the German Consumer Price Index (CPI) for the years 1980-1996 (DEstatis 2013a). All other graphs in this and the following chapters focusing on 2007 until today use money of the day prices, i.e. nominal prices.

2.1.1. Energy commodities

Wholesale energy prices have increased significantly in the years until 2008. Since then, price developments have been heterogeneous, differing between energy commodities, and between world regions. In Europe, prices have generally increased again after a sharp decline in early 2009, and are on high levels in real terms compared to the last two decades. However, the 1980ies and earlier decades partly saw higher prices in real terms than today. The rapid increase in energy prices over the past few years, however, is rather unprecedented historically, and was not anticipated by the majority of future price projections.

Figure 2 shows long term price trends for crude oil, natural gas, steam coal, uranium, and electricity in December 2012 real term prices. Prices of the different energy commodities shown are on a per Megawatt hour (MWh) basis, except for uranium, which is displayed per pound on the right axis. However, a direct comparison of per MWh prices may be misleading as energies are used for different purposes, and conversion technologies such as power plants have different efficiencies for different energies.
Brent crude oil\textsuperscript{13} mostly developed sideways from the late 1980s until 2000. Between 2000 and 2005, prices increased slightly. From 2005 until 2008, the spot price increased almost continuously and reached a peak of about 93 \( €_{2012}/\text{barrel} \)\textsuperscript{14}. Shortly thereafter, the price dropped significantly but in the following three years climbed again to a level of around 90 \( €_{2012}/\text{barrel} \).

In general, the natural gas price\textsuperscript{15} follows a similar development pattern as crude oil, with a time lag of about 3 to 6 months. Five months after the crude oil price peak in June 2008\textsuperscript{16} the natural gas import price into Germany reached its all time high of 9,600 \( €_{2012}/\text{TJ} \) (TJ) before dropping by about 47\% to 5,102 \( €_{2012}/\text{TJ} \) in late 2008 (see section 2.3 for more details).

**Figure 2: Long-term price trends of crude oil, steam coal, uranium and NG**

Looking at the long-term trends and notable peaks, steam coal import prices fell from their high in 1981/82 at around 260 \( €_{2012}/\text{ton} \) (t) to an almost constant level of 75 \( €_{2012}/\text{t} \) with two short floor price periods in 1999 and again in 2003.

\textsuperscript{13} Brent Crude (or Brent Blend BFOE) is the most relevant type of crude oil for Europe. Despite its marginal share of worldwide produced crudes (\( \sim 0.3\% \)) it is used as price reference for about 2/3 of all physically internationally traded crudes. Brent Blend BFOE consists of oil from the four oil fields Brent, Forties, Oseberg and Ekofisk. WTI (West Texas Intermediate) also has a small share of worldwide production (\( \sim 0.4\% \)) and is the second important crude that is used as price reference.

\textsuperscript{14} Please note that these are monthly average prices, not daily averages. For the conversion of barrels of crude oil to MWh, a factor of 1.59 MWh/bbl has been used.

\textsuperscript{15} The German import price is taken as indicator here.

\textsuperscript{16} The single highest daily price was recorded in July 2008, while the highest monthly average prices was in June 2008.
In 2008, the steam coal price reached its highest level in recent years at 120 €2012/t. Steam coal prices in general show the same price trends as crude oil prices with delays varying between 2 and 10 months; e.g. the 2008 price peak had a delay of 2 months relative to the oil price peak, while the subsequent low price period started with a delay of around 7 months. The Brent oil price peak in September to November 2000 was followed by a broader peak in German coal import prices around July to September 2001, or around 10 months later (see section 2.4 for more details and for reasons behind price developments).

It is noteworthy that oil, gas, and coal prices were very close to each other in the 1990ies, with notably coal and gas being very similar and oil slightly higher. In 1999, prices started to diverge with the oil price highest, the coal price lowest, and the natural gas price in between. While oil, gas, and coal prices were almost identical on a per-energy basis in 12/1998, coal prices increased by 115% until their peak in 7/2008, while gas and oil prices increased by 263% and 672%, respectively, in the same period.

The course of the electricity price curve reflects the energy price peak in 2008 with a 175% increase from 2/2007 to 9/2008; however, a previous peak in 2/2006 had been just 13% lower than the 9/2008 peak. The electricity price curve is significantly more volatile than that for oil (see section 2.5 for more details).

After a long period of low prices between 1989 and 2005, uranium prices hit a record high of above 100 €2012/pound (lb) in 2007. Since 2008, the price has systematically remained below the 1985 level of 50 €2012/lb. The uranium price curve does not suggest a relevant correlation with any other energy commodity.

This long-term trend overview shows that the different energy commodities follow fundamentally different developments: Coal is substantially cheaper than it used to be three decades ago, while natural gas and oil prices have significantly increased compared to the 1990ies. Oil price peaks are seen to have an effect on all energy commodities other than uranium. They are reflected in the gas price with a delay of about 3 to 6 months, and in the coal price with a delay of 2 to 10 months.

2.1.2. Non-energy commodities

The energy price trends discussed above are an element of the wider economic development. Economic growth generally impacts most commodity prices, energy and non-energy, through increasing demand. The energy price increases starting around the year 2000, culminating in mid-2008, and increasing again in recent years after a sharp decline in 2008 are well linked to world economic growth. Similar patterns can be seen in other commodities, notably metals and agriculture. Figure 3 shows the price developments of agricultural products, precious metals, and fertilisers relative to energy. A correlation analysis carried out by the US Energy Information Administration (EIA; see Figure 4) shows that parallel price developments started to be much more prevalent since 2008 than in the years before.

In addition to economic growth, constraints in natural resources are another element of price developments, both in fossil energies and in metals and phosphate fertilisers. With easily accessible and large deposits showing signs of depletion varying by resource type and geography, even smaller and deeper deposits of natural resources need to be tapped, with decreasing quality (decreasing ore content, increasing sulphur content in coal or oil, etc.), leading to higher production cost.
Figure 3: Price indices for various commodities

Source: Study authors based on (World Bank 2013)

Figure 4: Correlations between daily price changes of crude oil futures and other commodities in the USA

Source: (EIA 2013)
2.1.3. Future projections of long-term trends

The future projection of long-term price trends involves many unknowns. Experience over the past decade has seen price developments on global wholesale markets that were not anticipated by the majority of future energy price projections. The strong increases of oil, gas and coal prices leading to the 2008 peak as well as current price levels came as a surprise to most experts. Past price projections underestimated future prices significantly, in most cases projecting 2030 to 2050 prices below values reached within a few years from the original projection.

As a general observation, price increases of fossil energies have a tendency to be underestimated by most projections, while on the other hand costs of renewable energies have decreased much quicker than anticipated, and thus tend to be overestimated (see e.g. DIW 2013a, Altmann et al. 2011). Unfortunately, a systematic and focused analysis of strengths and shortcomings of future price projections is lacking.

As discussed in (Altmann et al. 2011) a major input for future fossil energy price projections is the physical availability of the resources. Optimistic assessments of the future global availability of oil, natural gas, and coal lead to constant or only slightly increasing long-term price projections. Pessimistic resource assessments including so-called peak oil / gas / coal analyses lead to sharply increasing prices. One of the few analyses on such a basis has been published by (Lutz et al. 2012) who project a “base line”17 oil price in the range of 130 $/barrel (bbl) in 2020, but a “peak oil” price of between 300 and 600 $/bbl in 2020, depending on assumptions for energy efficiency improvements etc.

PRIMES projections in the framework of the Impact Assessment for the Roadmap 2050 (EC 2011) show, in contrast to earlier PRIMES modelling runs (E3M 2010, E3M 2008, E3M 2006, E3M 2003), various future energy price scenarios with significant spreads between the different scenarios. For oil, 2020 prices range from 79 to 132 $/bbl, while for 2050 they range from 84 to 162 $/bbl. However, the range is still small compared to the above-mentioned peak oil projections.

In spite of differences between various future price projections, they generally agree that oil prices cannot be expected to go down again to the levels of the 1990ies.

2.2. Crude oil

This section gives an overview of crude oil price developments in Europe and the USA. Oil price formation mechanisms are not in the scope of the present analysis – oil prices are taken as an input here.

Brent and WTI (West Texas Intermediate) oil spot prices as well as the average crude oil import costs for the USA and IEA Europe18 developed on par until the end of 2010. In 2011, WTI and Brent spot prices started to decouple (see Figure 5). Shortly thereafter, the average US crude oil import price also decoupled from the WTI spot price. This gap between Brent and WTI crude oil prices has ranged between 7 and 20 €/bbl, while the gap of European and US average import costs has stayed below 12 €/bbl.

The price difference between Europe and the USA, both in spot prices and in import costs, is presented in Figure 6, showing that a systematic difference started to appear at the end of 2010.

17 Comparable to the IEA World Energy Outlook 2010 “new policy” scenario according to the authors
18 IEA Europe includes Austria, Belgium, the Czech Republic, Denmark, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Luxembourg, the Netherlands, Norway, Poland, Portugal, the Slovak Republic, Spain, Sweden, Switzerland, Turkey, and the United Kingdom (IEA 2013a).
It is attributed to transport capacity restrictions within Texas, which do not allow transporting all oil produced to the sea ports for international trade (Ströbele et al. 2012). Similar as with gas prices, a permanently higher European oil price may trigger a discussion on the resulting effects on the competitiveness of the European economy and on required policy action. However, efforts to overcome these restrictions are underway, and are expected to eventually eliminate the spread in the foreseeable future. However, the export of crude oil from the USA is generally forbidden with several exemptions (Vann et al. 2013). These legal constraints have recently led to a situation where even sufficient transport to the sea ports has not resulted in eliminating the spread caused by continued domestic surplus. This may lead to export to Canada to develop in the near future, which is not legally restricted for use or consumption therein (Vann et al., 2013). Also, imports to the US gulf ports may go down because of the price spread.

**Figure 5: Crude oil spot prices and import costs for Europe and the USA**

![Crude oil spot prices and import costs for Europe and the USA](chart.png)

**Source:** Study authors based on (EIA 2013a), (IEA 2013), (Eurostat 2013a)

---

For an overview on energy trade between the USA and Canada see e.g. J. Slutz, The U.S. - Canada Energy Relationship and the Growing Role for Asia, Pacific Energy Summit, 2013 Summit Working Paper, [www nbr org](http://www nbr org).
Regional differences of crude oil import costs in Europe are very small as shown in Figure 7. Figure 7 and Figure 8 show the difference of the crude oil import price of selected countries to the European average.

**Figure 6: Spread between European and US crude oil spot and import prices**

**Source:** Study authors based on (EIA 2013a), (IEA 2013), (Eurostat 2013a)

**Figure 7: Average crude oil import costs into selected European countries and the USA**

**Source:** Study authors based on (IEA 2013), (Eurostat 2013a)
For most of the periods between 2007 and April 2013 Spain’s crude oil import costs are below the European average. In contrast, the UK’s import costs are usually above the average. Germany’s and Italy’s import costs are occasionally above or below the average. Differences are within plus/minus five €/bbl, and most of the time remain within plus/minus 2 €/bbl. Depending on the crude oil price, this corresponds to a variation of 2-6% from the European average price. As these differences are small, they are only marginally important for differences in energy prices between Member States.

In general, oil prices will remain high (see section 2.1.3), and thus continue to be a concern and a key element in policy discussions. Regional price differences are expected to prevail particularly during times when supply and demand do not match well locally or globally.

### 2.3. Natural gas

#### 2.3.1. Introduction

Natural gas is a major primary energy carrier. Some 21% of the world energy demand is covered by natural gas (IEA 2013b). It is projected that the global demand for natural gas will be rising in the future. In the IEA New Policies Scenario, the compound annual growth rate for worldwide gas demand between 2011 and 2035 is at 1.6%/year. Moreover, the EU’s gas demand is projected to increase by 0.5% per year over the same period (IEA 2013b).

In 2011, the EU Member States consumed nearly 492 Billion cubic meters (bcm) of natural gas. The IEA estimates that until 2035 the EU gas demand will increase by roughly 11%, to a level of 554 bcm. This increase appears to be rather limited when compared to the projected evolution of global gas demand, which the IEA expects to increase from 3,370 bcm in 2011 to 4,976 bcm in 2035 (+31.6%). The rising demand for natural gas will be largely driven by the non-OECD world. Between 2011 and 2035, gas consumption in the non-OECD countries is expected to soar from 1,773 to 3,086 bcm (IEA 2013).
Both in the EU and on a global level, natural gas will continue to be an energy carrier of major importance. Before discussing market fundamentals, various price formation mechanisms, and the differences between EU Member States, a short overview on price trends is given. Finally, the main findings are summarised by presenting direct and indirect drivers impacting natural gas prices.

2.3.2. Price trends

As Figure 9 shows, both the natural gas (NG) spot price in the United Kingdom (UK) and the average import price into European Member States follow the general trend of the crude oil spot price with a time lag of about 3-4 months and 4-6 months, respectively.

From the beginning of 2007 until June 2008, monthly average oil prices increased by 107% from 41 €/bbl to 85 €/bbl. Subsequently, prices sharply declined by 183% to 30 €/bbl in December 2008. In this timeframe, EU natural gas import prices increased by 93% from 4.3 €/MMBtu (April 2007) to 8.3 €/MMBtu (November 2008), returning to 4.4 €/MMBtu (August 2009) thereafter. UK gas spot prices showed a similar development, but with lower absolute prices in early 2007 and late 2008: from 2.1 €/MMBtu to 7.8 €/MMBtu (a 271% increase), and back to 2.0 €/MMBtu.

Natural gas import prices in general reflect gas prices mainly based on long-term, oil-indexed contracts, while spot prices reflect gas-on-gas competition. Consequently, it is interesting to compare these two types of gas prices and to analyse the impact of the oil price on them (see section 2.3.6).

Since mid-2009, natural gas import prices in Europe increased steadily until early 2012, and have remained constant since then (see also Figure 10). The UK spot price, in contrast, increased until end-2010, remained constant until mid-2012, and has significantly increased since then. According to latest figures, it has come back down to mid-2012 values.

Figure 9: Natural gas import and spot prices in Europe

Data source: Study authors based on (EIA 2013a), (IEA 2013), (EC 2013b), (Eurostat 2013a)

---

20 Time lags are estimated by maximising the correlation depending on assumed time lag.
The volatility of the NG spot price is somewhat higher than for crude oil and most short term fluctuations do not show any obvious link to the crude oil spot price. The EU average import price is in most periods above the UK NBP (National Balancing Point) spot price.

**Figure 10: Natural gas price correlation to Brent crude oil in Europe**

The statistical correlation is very high with a correlation coefficient $r=0.82$\(^{21}\) between the Brent spot price and the UK gas spot price at 3-4 months delay\(^{22}\), and with $r=0.94$ between the Brent spot price and EU gas import price at 5 months delay\(^{23}\). Figure 10 shows these correlations graphically.

For most parts of the period considered (2007-2013), the UK and the US gas spot prices are decoupled (see Figure 11). After a period of price parity during 2009 and the beginning of 2010, spot prices strongly and permanently decoupled again with US prices remaining low and even declining from 4 €/MMBtu to below 2 €/MMBtu, and back to around 3 €/MMBtu by early 2013. At the same time, UK natural gas spot price increased to up to 9 €/MMBtu in early 2013. US NG spot and NG import prices are almost on par while European import prices in general have a premium on the UK NBP spot price with the exception of the strong spot price spike in early 2013. Since 2010, European NG prices, both import and spot, have shown a similar upward trend as crude oil. In contrast, the US

\(^{21}\) The correlation coefficient $r$ can have values between -1 and 1; values above 0.5 or below -0.5 are generally taken as strong correlations, while values above 0.3 or below -0.3 still indicate moderate correlations. Other values indicate weak or no correlations.

\(^{22}\) The delays, or time lags, of correlations are estimated by calculating the correlations for different delays in steps of one month; the delay is fixed where the correlation coefficient is highest. For the correlation between Brent spot oil prices and UK gas spot prices, the correlation at 3 months delay is equal to the correlation at 4 months delay.

\(^{23}\) The significance level based on the $t$-value test is beyond 0.01%, i.e. the probability is 99.99% that the correlation is actual and not by chance. However, correlations do not give any evidence for a cause and effect relationship.
price has stayed at a low level of about 2 to 3 €/MMBtu. There are no correlations between US oil spot prices and US gas prices in the considered period since 2007\textsuperscript{24}.

**Figure 11: Natural gas import and spot prices in Europe and the USA**

Source: Study authors based on (EIA 2013a), (BAFA 2013), (IEA 2013), (EC 2013b), (Eurostat 2013a)

### 2.3.3. Market fundamentals

Being a heterogeneous product, the composition and key characteristics of natural gas vary depending on the place of origin. Before natural gas can be used commercially, it must undergo a treatment process to remove non-methane hydrocarbons and impurities. It then fulfils the characteristics of a search good\textsuperscript{25} as parameters affecting distribution and combustion can be readily measured at the delivery point, limiting transaction costs.

Natural gas is mostly transported via pipelines, which account for 68% of total gas trade (IEA World Energy Outlook, 2012). In the last decade, trading liquefied natural gas (LNG) has been gaining importance, especially over long distances. LNG is already responsible for 42% of interregional gas trade (IEA World Energy Outlook 2012). In general, transportation costs are significant due to the low energy density of natural gas and may, in some cases, exceed exploration and extraction costs.

Storage is an essential element of the natural gas supply chain. Storage is required to ensure the operation of the gas network, e.g. to balance flows in pipeline systems or to maintain contractual balance. A second reason for storage is to address demand variability, e.g. seasonal storage to cope with peak demand. Finally, stocks are also a tool to reduce the risk of supply disruptions. While stocks could theoretically also be used to address price volatility in competitive markets, the high costs of storage due to the relative low energy density of natural gas, for example compared to oil, makes this less suitable than oil. Experiences with the release of strategic oil stock to address price hikes have generally not been very positive.

\textsuperscript{24}Correlations have been seen in the past during periods of tight market conditions; see e.g. (Energy Charter Secretariat 2007).

\textsuperscript{25}When the characteristics of a product (e.g. its heating value) can easily be evaluated before purchase, in economics the product is typically referred to as a search good.
Production of natural gas has more than tripled since 1970, and it continues to grow as new sources are explored and new technologies improve extraction practices. In 2012, global production amounted to 3,364 bcm. However, only 4.4% (i.e. 150 bcm) of that were produced within the European Union, and the trend is declining. The most important gas-producing countries globally were the United States (681 bcm, 20.4% of global production) and Russia (592 bcm, i.e. 17.6%). Generally, gas production is concentrated in the Americas and in Eurasia, as illustrated in Figure 12. The most notable producing countries in the EU are the Netherlands (1.9%) and the United Kingdom (1.2%). Apart from Russia, the largest gas producers in the EU neighbourhood are Norway (3.4%) and Algeria (2.4%).

As shown in Figure 13, power generation is generally the largest consumer of natural gas. It is also used in buildings (mainly for space and water heating), in industry (e.g. steel, glass, paper, fabrics, brick, ceramic tiles), in energy sectors other than power generation (oil and gas industry operations), for non-energy use as a raw material (e.g. paints, fertilisers, plastics), and in transport (natural gas vehicles).

The EU heavily relies on imports to satisfy its gas consumption. In 2012, the EU imported 294 bcm of natural gas, i.e. 66% of its consumption. Due to a declining domestic production, the import dependency of the EU is increasing (BP 2013).

More details on the fundamentals of gas markets can be found in Annex A.
2.3.4. Price formation mechanisms

Introduction

In Europe, one can distinguish three main price formation mechanisms for natural gas:

- Long-term contracts (LTCs) with oil-indexation.
- Gas-on-gas competition (GOG).
- Regulated prices.

In the first case, the price of imported gas is directly linked to the price of oil or oil products. More recently, new indexation formulas have been introduced to these long-term contracts linking the gas price also to the value of other commodities, e.g. electricity, or to the value of hub-priced gas. In general, an LTC is a bilateral agreement between one buyer and one seller. The conditions of such a contract are negotiated between a gas producer (e.g. Sonatrach, Gazprom) and an importing utility, historically being the national incumbent (e.g. ENI in Italy). The length of the contract, the volume of the supplies and the nature of the indexation pattern are negotiated between the two parties. Having signed a contract with the gas producer, the importing utility resells the contracted gas volumes to its final clients (e.g. local distribution companies, large industrial consumers, residential users etc.). Important contract clauses are (at least partly) passed through, e.g. in particular a rather long duration of the contract.

The second case is a market-based price formation mechanism; the price of gas is derived from the intersection of a demand and a supply curve in a power exchange (so-called “hub”). Multiple buyers and sellers can be involved in this process, e.g. gas utilities and retailers acting both as sellers and as buyers or gas producers acting as direct sellers, e.g. to local distribution companies or large industrial consumers.

26 This does not necessarily refer to national incumbents only but also to key second-tier players in the gas sector, e.g. Enel or Edison in Italy.
27 For example, in order to sell gas acquired through bilateral contracts.
A key difference between this price formation mechanism and long-term bilateral contracts is the higher price transparency of gas-on-gas competition.

In the third case, the gas price is set by national energy regulators. Three types of regulatory pricing rules are applied in by the Member States: (i) prices caps, (ii) revenue caps and (iii) so called “Cost plus” regulation (ACER/CEER 2013). Note that the primary mission of these national authorities is to design and regulate the functioning of domestic gas and power markets.

Oil indexation has long been the dominant price formation mechanism in the EU (see Figure 25). However, in recent years, a shift towards gas-on-gas competition can be observed.

As of 2012, gas-on-gas competition amounts for roughly 45% of the European natural gas consumption, while some 50% of the consumption is traded under long-term contracts (see Figure 14).

**Figure 14: Natural gas price formation in Europe (2012 data)**

---

For example, in order to later resell this gas to residential and small business consumers.

Regional differences within Europe are discussed in section 2.3.5.
covers all remaining regulated costs, e.g. energy taxes, VAT, or special levies set by national governments in order to achieve energy policy objectives. Depending on the price formation mechanism, some components might be further split into additional components or grouped together (Dieter 2002).

The prices defined in long-term gas contracts typically include long-distance transportation costs (e.g. via pipeline) and limited volume flexibility. A minimum-pay obligation is often included in this type of contracts in order to secure a high utilisation of the transportation infrastructure, hence guaranteeing the payback for the heavy investment required to build the pipeline system and a minimum resource rent (Energy Charter Secretariat 2007). In gas-on-gas competition, the price is set by the demand/supply equilibrium in wholesale gas markets. Grid charges within the market zone are regulated costs and therefore not included in the wholesale market price. On the other hand, long-distance transportation costs may or may not be included in supply bids of market participants. These costs are not included if they are considered as sunk costs. This was especially the case in 2009. Back then, many suppliers had to fulfil long-term contracts with take-or-pay commitments in a period of low gas demand resulting from the economic crisis. Therefore, long-distance transportation costs were considered as sunk costs. Such a bidding behaviour can only be a short-term solution. In the long run, it is not sustainable (Dieter 2002).

Finally, short-term flexibility costs (e.g. for operating a storage unit) have to be covered. Again, it depends on the price formation mechanism, to which price component these can be attributed. In gas-on-gas competition, flexibility costs are reflected by the wholesale market price volatility, as the operator of a storage unit can act both as a seller and as a buyer of natural gas. In long-term gas contracts, some volume flexibility is typically included in the contract. For short-term flexibility, e.g. to balance short-term demand variations, storage units may have to be contracted. Suppliers with a long-term contract also have the option to utilise the wholesale market as a flexibility option, if the market liquidity is sufficiently high.

**Long-term contracts with oil-indexation**

Oil indexation was introduced when gas was still securing its position as a substitute fuel to oil in both power generation and heating. Oil-indexed gas is usually traded under long-term import contracts.

In 2012, 272 bcm, roughly half of the gas consumed in Europe (539 bcm) was priced directly from oil. The vast majority, i.e. 78% (212 bcm) of oil-indexed gas, was delivered to Europe through pipelines (IGU 2013a). Oil-indexed LNG supplies accounted for another 15%. The remaining 7% (20 bcm) came from oil-indexed domestic supplies, principally Italy, Germany, and the UK legacy contracts (IGU 2013a). Oil-indexation is a predominant pricing system in Southern Europe, whilst it is becoming increasingly unpopular in North-West Europe. At present, oil-indexed gas accounts for roughly 30% of internationally traded gas in this part of the continent (IEA 2013b).

---

30 Often referred to as “take-or-pay” clause.
31 A sunk cost is a cost that has already been incurred and which cannot be recovered to any major degree.
32 Under a take-or-pay contract a company either takes the product from the supplier or pays the supplier a penalty.
33 Note that the IGU definition of Europe is not identical to EU Member States as of 2012. More precisely, IGU also include Bosnia, Croatia, FYROM, Serbia, Switzerland and Turkey; and they seem to leave out Luxembourg, Sweden, Finland, Cyprus, Malta, Estonia, Latvia, Lithuania.
Public information on the structure of the indexation patterns applied in long-term gas contracts is scarce as neither gas exporting nor gas importing countries/companies are willing to disclose such information. The most recent publicly available data on indexation patterns applied in long-term gas contracts in the EU (shown in Figure 15) date back to 2004. At least back then, oil products dominated the price indexation of oil-indexed gas contracts (EC, ESI, 2007). The results of the Energy Sector Inquiry show that the indexation pattern varied across to the producing regions.

As shown in Figure 16, the indexation patterns used by Norwegian, Russian and Dutch producers are mainly based on oil products, while the Algerian indexation pattern is based on crude oil. These differences can be explained by the divergent evolutions of the gas industries. In the following, these developments are discussed in more detail.

**Figure 15: Indexation pattern under long-term gas contracts in the EU (based on 2004 data)**

![Indexation pattern under long-term gas contracts in the EU](image)

**Source:** EC Energy Sector Inquiry (2007)

---

34 An indexation pattern defines the commodities to which the gas price is indexed (IGU 2013a).

35 The Energy Sector Inquiry (ESI) was prepared by the Directorate General for Competition of the European Commission. The objective of the ESI was to assess the liberalization process in the energy sectors. The authors of this report tried to contact DG COMP and have access to updated data for the purpose of this study. However, energy companies are reluctant to disclose the structure of their long-term, oil-indexed contracts. While collecting the information on these types of contracts among the industry, the parties agreed that DG COMP will not share these data with third-party partners and will use it solely for the purposes of the ESI. The authors of this study tried to crosscheck the figures published in the report by the representatives of the gas industry. However, due to the high sensitivity of this information, data on oil-indexed, gas contract was not disclosed.
As shown in Figure 16, the indexation pattern used by the Dutch producers was dominated by oil products in 2004. This is explained by the history of the Dutch gas policy. The development of the gas industry in Netherlands was accelerated by the discovery of the Groningen gas field in 1959. Back then, gas consumption in Europe was limited, as gas was not a fuel of first choice. Moreover, in the early 1960s, the lifespan of fossil fuels appeared to be endangered by the appearance of nuclear power. Prompted to start a large-scale production and looking for stable profits, the Dutch government indexed the price of gas to the price of competing fuels, specifically oil products (IGU 2011). Price rebates were granted to encourage fuel-switching. Contracts for gas exports were signed with France, Belgium, and Germany. The introduction of long-term contracts allowed to share the risks related to price fluctuations (due to the movement of oil prices) between the Dutch producers and their foreign clients. Moreover, as producers obtained a long-term security of demand, investments in exploration and the build-up of transport infrastructure were fostered. Most importantly, the successful introduction of this pricing system secured the position of the fuel in power generation and heating. Between the mid-1960s and the mid-1970s, the Netherlands emerged as the first major supplier of natural gas in Europe. Inspired by this success, other countries embarked on gas exploration and production (Energy Charter Secretariat 2007).

Russia

The Energy Sector Inquiry showed a striking resemblance between the Russian and Dutch indexation patterns. Indeed, the Russians used the Dutch indexation pattern as a model while designing their own pricing formula. After the collapse of the Soviet Union the linkage to oil prices was conserved and remained robust. In 2004, oil products dominated the price indexation of Russian oil-indexed gas contracts, accounting for roughly 92% of all commodities included in the pricing formula.
**Algeria**

Unlike the Russian, Norwegian, or Dutch patterns, the Algerian pricing formula was to a very large extent pegged to crude oil (69.5%), followed by light and heavy fuel oil (24.9% in total). This has not always been the case. Until 1981, Algeria’s gas exports to Europe were largely pegged to fuel-oil prices. In 1981, the regime in Algiers began to impose a linkage of gas prices to crude oil prices in its export contracts in order to align the price of crude oil to the price of natural gas (Hireche, 1989). The dominance of crude oil in the pricing formula applied by Sonatrach is a residual of this so-called “Gas Battle” (Energy Charter Secretariat 2007).

**Norway**

The start-up of large-scale production in Norway in the early 1980s coincided with the beginning of the “Gas Battle” engaged by Sonatrach. Initially, Norwegian producers tried to base their pricing formula on a mélange of crude oil and oil prices. However, they started revamping the pricing strategy in 1986. Henceforward, the Norwegian indexation pattern was based on light fuel oil complemented by heavy oil and other commodities (Energy Charter Secretariat 2007). In 2004, oil products dominated the pricing formula applied in Norwegian gas contracts.

**The United Kingdom**

In the case of the UK, the results of the Energy Sector Inquiry showed that in 2004 the main price determinant was the spot market price of gas (37%) followed by inflation indices (28.1%). Oil and its derivatives accounted for merely 20.4% of the final price of gas. Since 1948, up to 1986, the British market was controlled by British Gas, a state owned gas utility. British Gas held a monopoly for the procurement and the distribution of natural gas (Webber 2010). Moreover, throughout this period of time, the company was the sole buyer for all gas volumes produced in the North Sea. This situation changed with the adoption of the Gas Act 1986 initiating the process of liberalisation of the British market. The process was completed in 1998. The abovementioned developments resulted in the establishment of hub-based pricing in the UK. The National Balancing Point (NBP) emerged as the price indicator in Britain (Webber 2010). Gas prices were set by the market conditions such as: the costs of production, fuel competition, the interactions of the market players, and seasonality. In 1999, the UK-Belgium gas interconnector was inaugurated, linking Britain to continental Europe. Shortly after the inauguration of the interconnector, the UK started to export gas to the mainland. In times when gas on the continent was traded under long-term, oil-indexed contracts bound by destination clauses, the possibility to import gas from the UK appeared as an attractive alternative. Gas supplies from the UK were not only contracted over relatively shorter period of times, but the buyer was able to choose between delivery points, fostering arbitrage between the UK and the mainland (Energy Charter Secretariat 2007).

The Energy Sector Inquiry also showed that the price indexation patterns varied depending on the region of the importing company, largely according to the origin of gas supplies. As illustrated by Figure 17, the prices of gas imported to the UK were largely pegged to the prices of gas on spot markets.

---

36 When inaugurated, the interconnector had a capacity of 20 bcm/year from the Bacton (UK) to Zeebrugge (Belgium). The flow capacity from Zeebrugge to Bacton was of 8 bcm/year; in 2007, it was expanded to 25.5 bcm.

37 Destination clauses are contract provisions that forbid the buyer to resale purchased gas volumes to a third country (Energy Charter Secretariat).
Light and heavy fuel oil accounted for only 31% of the pegging. The impact of oil and its derivatives on the final price of gas traded under long-term contracts was much stronger in continental Europe, i.e. both Western\(^{38}\) and Eastern Europe\(^{39}\) (where they respectively accounted for 84.7% and 96% of the indexation). Figure 17 also shows the indexation pattern for long-term gas contracts by importing regions. For example, gas is predominantly indexed to fuel oil, light and heavy oil in Eastern Europe – with no gas-on-gas competition being present at all. This reflects the extreme dependency from the respective suppliers in that region at this point in time.

In general, long-term contracts support long-term and capital-intensive investments in exploration, production, and infrastructure (IGU 2013a) resulting from the desire for long-term security of demand. Moreover, due to the formulas applied in long-term, oil-indexed contracts (3 to 6 months average), the influence of oil price fluctuations is reduced. However, because of the absence of price-volume linkage under this model, the supply-demand equilibrium is distorted (IEA 2007). To address this problem, oil-indexed contracts commonly include a review clause, allowing a regular adjustment of the base prices and of the indexation formulas to the price developments of the competing fuels across the different sectors (power, industrial, and residential) (Davoust 2008). In recent years, mixed indexation patterns in long-term gas contracts have become more common. For example, the French utility Poweo reportedly signed a long-term contract (20 years) with Statoil in 2010, which is indexed to a combination of gas, electricity, and \(\mathrm{CO}_2\) certificate prices\(^{40}\) (Statoil 2010). For a power producer, such an indexation can be more favourable than other indexations, as gas-fired power plants are usually not in-the-money in times of low electricity prices and/or in times of low carbon prices.

**Figure 17: Indexation pattern under long-term gas contracts according to the importing regions (based on 2004 data)**

![Indexation pattern under long-term gas contracts](image)

**Source:** EC Energy Sector Inquiry (2007)

---

\(^{38}\) Austria, Belgium, France, Germany, Denmark, Netherlands and Italy.

\(^{39}\) Poland, Czech Republic, Slovakia, Hungary and Slovenia.

\(^{40}\) The exact contract details have not been disclosed.
The changing structure of indexation patterns is caused by the fact that in most of the world oil and gas are no longer competing fuels for power generation. Figure 18 shows that between 1973 and 2011 the shares of fossil fuels in power generation changed radically. In 1973, electricity produced in oil-fired power stations accounted for 24.6% of the world production; the share of power produced in gas-fired plants was of 12.2%. By 2011, the share of electricity produced through gas combustion rose to 21.9%, whereas the share of oil-fired power plants decreased to 4.8%\textsuperscript{41} (IEA 2013).

At present, natural gas is increasingly competing with renewables, nuclear, and coal for power generation (Valiante & Egenhofer 2013). Moreover, with the “globalisation” of gas markets, regional markets are becoming more intertwined. Changes in prices, supply, and the economic condition of a region can all have an impact on the price of gas on another regional market. This interdependence was illustrated by the economic crisis and the shale gas revolution in North America which created an oversupply of gas in some regional markets\textsuperscript{42}.

The shale gas revolution resulted in an oversaturation of the US gas market. This contributed to the decoupling of the gas prices from the oil price, as shown in the sections hereunder. Inevitably, the prices of oil-indexed gas deviated from the prices of gas traded under gas-on-gas competition. With reference to publicly listed hub prices, consumers then demanded lower prices from their (gas-importing) utilities (see also next section). As a result, midstream gas companies are asking their suppliers for more flexibility on prices and volumes (IEA 2011).

\textbf{Figure 18: World electricity generation – 1973 vs. 2011}

\begin{figure}[h]
\centering
\includegraphics[width=\textwidth]{figure18}
\caption{World electricity generation – 1973 vs. 2011}
\end{figure}

\textbf{Source:} (IEA 2013c)

\textsuperscript{41} It is worth noting that 98% of the primary energy supply in Malta is based on oil. Cyprus is also heavily dependent on oil, representing over 95% of its energy mix. For more information: European Commission, “Energy challenges and policy: Commission contribution to the European Council of 22 May 2013”.

\textsuperscript{42} According to some observers, the oil indexation model was unable to reflect these developments (Stern, Rogers 2011). Gazprom, on the other hand, is strongly defending oil indexation. For example, in January 2013, Sergei Komilov (Gazprom Export) published a paper entitled “Pricing the Invisible Commodity” in which he defended inter alia, the rationale for oil indexation.
These developments were accompanied by several legal proceedings; in September 2012, the European Commission opened a proceeding against Gazprom to investigate whether the Russian supplier abused its dominant position on the gas markets in Central and Eastern Europe. Among other things, the European Commission accused Gazprom of having contravened the free movement of gas across the Member States. In the context of completing the internal energy market, “destination” clauses might be defined as incompatible with the free movement of goods, one of the fundamental freedoms of the single market (Riley 2012); more information is provided in section 5.1.1.

In June 2013, the International Court of Arbitration of the International Chamber of Commerce issued an arbitration decision regarding a dispute between Gazprom Export and RWE. The court forced Gazprom to include a gas market indexation mechanism in its long-term gas contract with RWE Supply & Trading CZ. Moreover, the ruling obliged Gazprom to reimburse certain payments made by RWE since May 2010. According to the Director General of Gazprom Export, the price formula was reviewed, but not under the conditions allegedly originally demanded by RWE (GAZPROM, 2013).

**Gas-on-gas competition**

Gas-on-gas competition is a market-based pricing mechanism. Within this mechanism, the price of gas is based on the equilibrium between supply and demand and not directly linked to any alternative fuel, hence reflecting the regional and global gas market fundamentals outlined in section 2.3.3. Natural gas is traded at contractual points called physical hubs or virtual trading points. The difference between these is shown in Table 1.

Currently, the most liquid gas markets in the world are the Henry Hub in the US and the National Balancing Point (NBP) in the UK. In the late 1970s, the United States and Canada were the first OECD countries to liberalise their gas markets. They were followed by the UK, where the process of liberalisation was completed in the early 1990s. The creation of a virtual hub, the NBP in 1994, triggered the use of this pricing mechanism in the UK, making it the first EU market to offer a reliable reference price.

Such market pricing of natural gas can apply to contracts of any length in time. Buyers and sellers can thus enter into various forms of long-term arrangements to hedge their price risk (further explained in section 5.1). All interested parties can see the ‘true’ value of natural gas in publicly quoted hub prices (Heather 2013).

The transition to hub-based gas pricing has certain preconditions. First of all, wholesale prices need to be deregulated to allow for market pricing. There also needs to be a well-developed and interconnected transmission system. Guaranteed Third Party Access and separating transport from commercial activities is also crucial to ensure transparency and allow for new entrants. In addition, a sufficient number of market participants is needed in order to guarantee fair competition and a sufficient level of market liquidity. According to (IEA 2012b), the involvement of financial institutions is also beneficial.

---

43 RWE, “Analysis of the Arbitral Award Concerning the Price Revision Proceedings between RWE Supply & Trading CZ and Gazprom Export Completed”, press release, 1 July 2013
Table 1: Physical hubs vs. virtual trading points

<table>
<thead>
<tr>
<th>Physical Hub</th>
<th>Virtual Trading Points</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas is exchanged at a precise physical location</td>
<td>Gas is exchanged in a zone (a part of gas network: national or regional TSO)</td>
</tr>
<tr>
<td>Gas is delivered/taken off to/from this location/place</td>
<td>Gas is delivered/taken off to/from this zone</td>
</tr>
<tr>
<td>Key services offered:</td>
<td>Key services offered:</td>
</tr>
<tr>
<td>• Transportation between and interconnections with other pipelines</td>
<td>• Transportation between the entry and exit points</td>
</tr>
<tr>
<td>• Physical coverage of short-term receipt/delivery balancing needs</td>
<td>• Network “short-term” balancing</td>
</tr>
<tr>
<td>Examples: ZeeHub, CEGH, Henry Hub (US)</td>
<td>Examples: NBP, GasPool, TTF, PEG, TIGF, PSV, AOC, IBP, NCG</td>
</tr>
</tbody>
</table>

**Gas pricing in Europe**

In the EU, the Third Energy Market Package provides for the legislative framework to create an internal market and enable hub-based pricing. The liberalisation and the integration of the national energy markets into a single energy market is a complex and multi-stage process. Between 1996 and 2009, three legislative packages were enacted to trigger the completion of an internal energy market. Among them, the Third Energy Package adopted in 2009 is often portrayed as the ultimate enabler for the creation of a single gas market by 2014. The core provisions of the Third Energy Package include:

- The unbundling of Transmission System Operators.
- The creation of the Agency for the Cooperation of Energy Regulators (ACER).
- Entry-exit organisation of access to transmission networks (i.e. entry and exit capacities must be bookable independently from each other and no distance-related fees must be applied).
- The development and the implementation of 12 binding European-wide Network Codes designed to regulate cross-border gas flows. Given their importance for the completion of the internal gas market, Network Codes are sometimes referred to as “the Fourth Energy Package”.

In September 2010, the European energy regulators were empowered by the Madrid Forum to design a target model enabling the creation of an internal market for natural gas. In December 2011, the Council of European Energy Regulators presented its vision of a European Gas Target Model. In March 2012, the 21st Madrid Forum endorsed the Gas Target Model developed by the Council of European Energy Regulators (Yafimava 2013).

The Gas Target Model foresees the creation of coexisting, well-functioning, interconnected regional wholesale markets throughout the European Union.

---

44 National Network Codes are being developed independently by the Member States.
45 The Madrid Forum (or the Gas Regulatory Forum) was created by the European Commission in 1999 in order to discuss the creation of the Internal Energy Market. It regroups representatives of the European Commission, Member States, transmission system regulators, national regulatory authorities, system users, consumers, suppliers, power exchanges and traders (Troesch 2003).
These wholesale markets should form adjacent entry-exit zones in which entry and exit capacities are allocated independently. According to the concept, gas should be able to flow freely from low demand/price areas into high demand/price areas. The creation of the above-mentioned entry-exit zones should facilitate the development of hubs or virtual trading points. In a nutshell, these interconnected markets should be able to reflect the supply and demand equilibrium (CEER 2011).

According to the concept of the Gas Target Model, these markets should:

- Be sufficiently robust: the gas demand within an entry-exit zone should be at least 20 bcm per year.
- Have diversified supply routes: gas traded on the wholesale market should be supplied from at least three different sources.
- Be open to competition: the level of the market’s concentration should be sufficiently low, i.e. a Herfindahl-Hirschman Index below 2000.
- Have a certain volume of trade: a churn ratio of at least 8.

According to the IEA, “2012 was a positive year for gas hub trading in Europe” (IEA 2012b). Both physical delivered (throughput) volumes as well as traded volumes increased by 13% and 14%, respectively (ibid). As shown in Table 2, there are a number of gas hubs in Europe.

The NBP continues to be the major European gas hub in terms of physical volumes. Only when taken together, the continental European hubs are now larger than the NBP in terms of physical delivered volumes. The IEA expects the NBP to remain the benchmark for gas in the British Isles, while the Dutch TTF seems to be becoming the benchmark for North West European gas supplies. The Austrian CEGH has the potential to become the reference hub for Central and Eastern Europe (IEA 2012b).

### Table 2: Gas hubs in the EU: localisation and churn rates (2011 data)

<table>
<thead>
<tr>
<th>Name of the hub</th>
<th>Localisation</th>
<th>Churn rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>PSV</td>
<td>Italy</td>
<td>2.4</td>
</tr>
<tr>
<td>Zeebrugge</td>
<td>Belgium</td>
<td>4.4</td>
</tr>
<tr>
<td>TTF</td>
<td>Netherlands</td>
<td>4.1</td>
</tr>
<tr>
<td>CEGH</td>
<td>Austria</td>
<td>3.7</td>
</tr>
<tr>
<td>PEG</td>
<td>France</td>
<td>3.4</td>
</tr>
<tr>
<td>Gaspool</td>
<td>Germany</td>
<td>2.3</td>
</tr>
<tr>
<td>NCG</td>
<td>Germany</td>
<td>3</td>
</tr>
<tr>
<td>NBP</td>
<td>UK</td>
<td>14.1</td>
</tr>
</tbody>
</table>

**Source:** ACER (2011)

---

46 The Herfindahl–Hirschman Index is an economic indicator used to measure market concentration, i.e. the higher the Herfindahl number, the more concentrated is market power.

47 i.e. the total volume of gas traded compared to the volume of gas consumed (CEER 2011).
The liquidity of a hub indicates how easy it is to find a counterparty to trade with, i.e. buy or sell gas. This is often quantified by calculating the churn rate of a given hub, e.g. the net traded volume relative to final consumption. Among industry specialists, “there seems to be a sort of consensus that hubs with a churn rate of at least 10 to 15 can be considered to be liquid” (IEA 2013e). The British NBP is the only European hub whose churn rate is consistently above 10, followed by the Dutch TTF. It is worth noting that the churn rate of the Henry Hub in the US is “at least twice the level of the NBP” (Stern and Rogers 2011).

While Gazprom is still fighting hub indexation of their long-term contracts, some other suppliers have already accepted long-term contracts indexed to hub prices. This is the case of the Norwegian oil and gas company Statoil. According to one of the publicly communicated contracts, Statoil has signed a 10-year spot-indexed natural gas contract with the German company Wintershall, mainly linked to the NCG and GASPOOL hubs.

The impact of fundamentals on prices in liquid markets was demonstrated by a recent event: In March 2013, natural gas prices in North-Western Europe increased by more than a third compared to the previous month, due to an unusually (and unpredicted) cold March. As most seasonal storage was already exhausted, NBP prices increased significantly. Prices at continental hubs followed the increase of NBP prices, even though some price differentials remained for a couple of days, mainly because the interconnector pipeline was temporarily out of order (IEA 2013e).

**Gas pricing in the USA**

In the North American gas markets, gas-on-gas competition is the predominant pricing mechanism with a share of 98% in 2012 (IGU 2013). Producers have access to an open and competitive pipeline network and gas transmission system. This was a prerequisite for the development of fully liquid trading markets, as they now exist in the USA and in Canada. In the following, the key stages of the US development will be described briefly. Afterwards, the current situation will be discussed.

Originally, US gas prices were unregulated and low in comparison to competitive fuels. In the absence of a gas transmission network, prices reflected the actual situation of local demand and supply, i.e. producers only had access to local markets in the geographical proximity of large natural gas reserves resulting in an offer overhang in the affected markets. For this reason, the US government had started to build up a national pipeline system already in 1938. To avoid a time-consuming approval process for each pipeline section on a state level, the public authorities enforced eminent domain procedures at a Federal level. This allowed for a rapid expansion of pipelines and for absorption of surplus reserves. In 1954, the Supreme Court placed wellhead pricing (i.e. the production sector) under jurisdiction of the predecessor of the Federal Energy Regulatory Commission (FERC), thus entering a phase of regulation which lasted until 1978.

---

48 The churn rate measures how often a gas is traded and re-traded from the moment of its initial sale by the producer to the eventual purchase by the final consumer. It is difficult to measure the true level of churn in the EU, because large volumes are delivered under long-term contracts (Heather 2012). It is possible to approximate the churn rate by comparing the total traded volume to the net delivered volume (“net re-trading ratio”) or by comparing the total traded volume to the physical demand of the hub area (“gross market churn”). The churn rate is an indicator of the liquidity of a market/hub. It represents the ratio between the total volume of trades and the physical volume of gas consumed in the area served by a hub.

49 Note that the churn rate of the TTF is only greater than ten if one considers the gross churn rate, not when using the (more common) definition of the net re-trading churn rate. Another measure for the commercial success of a hub is the “Tradability Index”, indicating how narrow bid/offer spreads are across the trading curve (Heather 2013).


51 This refers to the right to take private property for the public good – in return for remuneration to the owner.
Based on historic prices in a rising cost environment, this kind of regulation proved to be unworkable and led to serious supply shortages. Once again, gas markets were unable to be cleared properly. This time, the cause was a demand overhang.

In 1978, the Congress enacted the Natural Gas Policy Act (NGPA) which started the transition from regulated wellhead prices to market-responsive pricing at the wellhead. The basic idea was to solve the demand problem by granting long-term incentive prices for new supplies and gradually removing price control on existing supplies. Initially, this led to the desired outcome. However, there was also a price effect on demand. This resulted in an oversaturation of the US gas market, also known as the “gas bubble”, which lasted until the late 1980s. As illustrated in Figure 19, the US gas demand peaked in 1972 and did not exceed this value until 1995.

The NGPA also formed the basis for third-party access to pipelines. Local distribution companies were allowed to buy a certain amount of gas from a supplier other than their contracted one. However, due to decreasing overall demand and existing contracts with a fixed volume, these companies were not able to take advantage of this flexibility option. The FERC addressed these issues in orders 380 and 436, essentially by relieving distribution companies from any contractual long-term take-or-pay obligations. Moreover, it enforced non-discriminatory third-party access to pipelines.

The development in the United States can be summarised as follows:

- Production and transport infrastructure build-up.
- Deregulation of wellhead prices.
- Removal of long-term obligations.
- Enforcement of third-party access.

**Figure 19: US natural gas annual consumption during the ‘Gas Bubble’ period**

![Graph showing US natural gas annual consumption](source: Energy Charter Secretariat 2007)

The main result of this development is that prices of natural gas in the USA are settled by market fundamentals, i.e. driven by supply and demand equilibrium. There are highly liquid and transparent markets for both gas as a product and the pipeline system that transmits and distributes natural gas. “Hubs” have evolved at pipeline interconnections bringing gas flows from different sources together and distributing it to different regions. One major pipeline interconnection point is located in South Louisiana, named the Henry Hub.
As shown by Figure 20, this particular hub is located at the heart of the South-Eastern Gulf region, one of the most important gas-producing regions in the USA. Situated at the junction of 13 different pipelines, it is well interconnected with other gas-producing regions, such as the Rockies and Appalachia and is the delivery point for future gas contracts traded at the New York Mercantile Exchange (NYMEX) (IGU 2012). Due to its rich interconnectivity, its importance is comparable to the oil pipeline junction in Cushing, Oklahoma, which is the reference point for the West Texas Intermediate (WTI) oil price.

Prices of gas across the numerous US hubs usually move together, following the price of gas at the Henry Hub. Price differentials between the Henry Hub and other US hubs generally reflect the transportation costs between those hubs but can also indicate specific market conditions. For example, in 2007, the production of gas in the Rocky region increased significantly. The local markets were unable to absorb these increasing volumes, whereas inter-state pipelines were quickly running at full capacity. As a consequence, gas producers had to sell gas produced in the Rocky region below the prices of gas reported at the Henry Hub. This situation – together with the continuously increasing volumes of indigenously produced gas – led to an infrastructural development. From 2007 to 2012, gas producers invested 32 million US-$ in the construction of new pipelines to smooth over interregional prices differences (IGU 2012).

Figure 20: Natural gas market centres and hubs in relation to major natural gas transportation corridors, USA, 2009

Source: (EIA 2013)

After the restructuring of the US gas markets, there was a common perception that the price of oil was no longer relevant for gas pricing. Indeed, there was no direct linkage like in Europe or Asia where oil-indexed gas contracts with long-term take-or-pay commitments are still a common contract type. Figure 21 shows the development of natural gas and crude oil prices in the US from January 1997 to August 2013.
The graph illustrates that there have been periods where the gas price followed the oil price. For example, in 2000/2001, the USA experienced a severe winter and prices of gas increased steadily until it became economical for dual-fired power generators to switch from natural gas to fuel oil. As a consequence, an indirect linkage between gas and oil prices was established. This period lasted until spring 2006. The decoupling was a result of increased supply (primarily by an increased usage of LNG imports but also by an increased domestic shale gas production), a demand response to the high prices and the market being fully satisfied.

Initially, the increasing demand in 2008-2009 was assumed not to be possibly covered by domestic production, so an increase in LNG imports and a possible re-coupling were partially expected (BPC 2013). As illustrated in Figure 11 and Figure 21, a re-coupling of oil and gas prices did not occur. Particularly since 2009, the difference between prices for oil and natural gas has been considerable. This is also due to the fact that the extraction of US shale gas continued, despite environmental concerns. The estimated reserves of shale gas rose by 35% from 2010 to 2011 (EIA 2013). Companies operating in the Marcellus reserve, which holds more than half of total shale gas in the USA, are now expecting to increase production by 20%-25% a year. Natural gas reserves estimates in the USA increased by more than 74% in the period 2006-2013 (BPC 2013).

It should be noted that the key factor for the dynamics of the shale gas revolution was a highly developed transport infrastructure. Project developers had access to an open and competitive pipeline network and transmission system.

**Figure 21: Natural gas and crude oil prices in the USA (1997-2013)**

![Graph showing natural gas and crude oil prices in the USA (1997-2013)](Source: EIA 2013)
**Regulated prices**

As discussed in the previous section, in 2012, 95% of the gas consumed in Europe was traded under oil indexation and gas-on-gas competition. While wholesale price regulation mainly takes place in non-OECD countries, the price of approximately 26 bcm of gas consumed in the EU was set by national authorities (accounting for 5% of the total volume). Price regulation was mainly applied for indigenous EU production coming from Romania, Hungary, Poland, Croatia, and Bulgaria (IGU 2013a).

**Conclusions**

As explained in the previous sections of this chapter, two pricing mechanisms for natural gas are predominant in the EU: oil-indexation and gas-on-gas competition.

Oil-indexation is often portrayed as being the “traditional” way of gas pricing. It was invented in the 1960s, in times when gas was still securing position as a valuable heating and power generation fuel. Under this pricing mechanism the prices of gas are to a large extent driven by oil prices. Supply contracts are signed over long periods of time (e.g. 20 years) and habitually include specific provisions (e.g. “take-or-pay” clauses).

In times of high oil prices (translating into high gas-indexed prices), critics of oil escalation underline the obsolescence of this pricing mechanism, by remarking that oil and gas are no longer competing fuels in the OECD world.

Gas-on-gas competition is a market-based pricing mechanism for natural gas. Whereas prices are set by the market forces of supply and demand, they are not fully independent from oil prices, as the US example shows. Supplies are usually signed over short periods of time, which can lead to higher price volatility. At present, gas-on-gas competition is gaining ground in Europe to the detriment of oil-indexation. EU policies favour the transition towards gas-on-gas competition.

**2.3.5. Regional differences in EU**

**Introduction**

As explained in the previous sections of this chapter, gas is a commodity with various price determinants; however, price formation mechanisms seem to be the most important price drivers. Whereas the shares of oil-indexation and gas-on-gas competition seem to be almost equal in the EU, differences appear on regional level. While some regions/Member States are almost entirely dependent on oil-indexed gas, others are more reliant on spot-indexed supplies. What is worse, these differences often concur with prices level differentials. In other words, a form of interdependency between the types of pricing mechanisms and the prices of natural gas can be observed across the EU Member States. This section aims at outlining these regional differences and explaining their drivers.

**Wholesale prices**

Figure 22 shows the day-ahead natural gas prices at selected European hubs between January 2012 and April 2013. Data are available for Austria, Belgium, France, Germany, Italy, the Netherlands, and the UK. Britain’s NBP has been the first EU market to offer a reliable reference price due to an early liberalisation and due to the fact that all of Britain’s gas supplies are market priced.

---

52 A “take-or-pay” clause obliges the client to pay for a defined volume of gas even if he is unable or unwilling to receive the defined volume of gas from the supplier (Polkinghorne 2013).
Moreover, the figure indicates a high correlation between gas prices in North-Western Europe (i.e. BE, NL, UK). Price differences can typically be attributed to long periods of cold weather, causing supplies to run short. As a result, the prices at the various hubs decouple from each other. More recently, there has been a price convergence between Austria and Italy following capacity release at the Austrian-Italian entry point (ACER/CEER 2012).

**Figure 22: Wholesale day-ahead NG prices at European hubs**

Source: (EC 2013b)

**Natural gas import prices**

As Figure 23 shows, the volatility and the general level of NG import prices are different for the countries shown. E.g. Germany has a medium to high price level but the volatility and the impact of the 2008 high crude oil price is comparably low. For Germany, the price increase between the lowest price in 2007 and the highest price in 2008 is 67%. In contrast, the UK seems to have a more volatile NG import price (price increase of 220% between 2007 and 2008) but at a lower price level. For the considered European countries the NG import prices in general seem to follow the crude oil price with a time lag of half a year. High correlations of $r=0.9$ for a 7 months delayed NG border price for Germany and of $r=0.79$ for a 5 months delayed UK import price exist. The average EU import price follows the Brent crude oil price with a delay of 5 months ($r=0.94$).

---

53 For the UK NBP spot price the highest correlation exists for a price delayed by 3 months ($r=0.82$).
Figure 23: Natural gas import prices into European countries

Source: Study authors based on (EIA 2013a), (IEA 2013), (BAFA 2013), (EC 2013b), (Eurostat a), (IEA 2013f)

Figure 24: Price difference of natural gas between individual countries and EU Member State average

Source: Study authors based on (Eurostat 2013a), (DKER 2013), (IEA 2013f)
**Price formation mechanism across European regions**

Over the last decade, significant changes have taken place in price formation across Europe. As shown in Figure 25, Europe experienced a continuous shift from oil indexation to hub-pricing (gas-on-gas competition). Since 2005, the share of gas sold under gas-on-gas competition increased from 15% to 45%, whereas the share of oil-indexed contracts decreased from 75% to 50%. However, there are significant regional differences across European regions.

**Figure 25: Price formation mechanisms in Europe (2005 vs. 2012)**

![Price formation mechanisms in Europe (2005 vs. 2012)](image)

Source: (IGU 2013)

Hub-pricing is predominant in North-western Europe and it is gaining ground in Central and Eastern Europe (IGU 2013). In 2011, 70% of the natural gas consumed in the UK, France, Belgium, the Netherlands, Germany, Austria, and Italy was traded under the gas-on-gas competition pricing mechanism. In 2012, this share grew to 83% (EC 2013d). The above-mentioned countries constitute the geographic core of the European gas market. Around 74% of European gas consumption takes place in these countries (Eurostat 2013).

Figure 25 shows that in less than 10 years the share of gas traded on spot markets in North-western Europe has risen from almost 28% in 2005 to 72% in 2012. This increase happened to the detriment of oil indexation. To some extent, this phenomenon can be explained by the declining levels of indigenous gas production in the UK (gas produced in Britain was sold under “traditional” oil-indexed contracts) and the shift towards gas-on-gas competition in the Netherlands.

---

54 It should be noted that the definitions of the geographical regions described in this section vary upon the source used. According to the definition applied by the European Commission in the Energy Sector Inquiry:
- Western Europe includes: Austria, Belgium, France, Germany, Denmark, Netherlands, and Italy;
- Central and Eastern Europe includes: Poland, Czech Republic, Slovakia, Hungary, and Slovenia.
According to the International Gas Union:
- North-western Europe includes: Belgium, Denmark, France, Germany, Ireland, Netherlands, and the UK;
- Central Europe includes: Austria, Czech Republic, Hungary, Poland, Slovakia, and Switzerland;
- Southeast Europe includes: Bosnia, Bulgaria, Croatia, Former Yugoslav Republic of Macedonia, Romania, Serbia, and Slovenia;
- Mediterranean Europe includes: Greece, Italy, Portugal, Spain, and Turkey.

55 The IGU definition of North-western Europe includes Belgium, Denmark, France, Germany, Ireland, Netherlands and the UK.
As the figure also shows, the popularity of gas-on-gas competition has also increased in Central Europe. While in 2005 this price formation mechanism for natural gas was almost not applied in this part of the continent, in 2012, the share of gas traded on spot markets was 35%. In the same period, the share of gas traded under oil indexation decreased from 85% to approximately 50%. This trend reflects the increasing imports of spot gas (e.g. from Germany). Moreover, experiencing adverse effects related to “opera pricing” (further explained below), some of the gas importers from Central Europe tried to renegotiate the structure of the indexation pattern applied in their long-term contracts.

For example, in November 2012, Gazprom and the Polish Oil and Gas Company (PGNiG) renegotiated the indexation formula for the long-term gas supplies to Poland via the Yamal-Europe pipeline. Under the revised formula, the prices of gas are still pegged to the prices of petroleum products. However, the altered supply rules also reflect the prices of gas on the European spot markets. According to some sources, the reviewed structure of the contract could translate into a price cut of roughly 15-20% for PGNiG. In October 2013, the two parties opened a new round of talks for the renegotiation of gas rates (Platts 2013). The share of regulated gas prices remained stable throughout the discussed period of time (15%) and was largely driven by indigenous gas production in Poland and Hungary.

As illustrated in Figure 25, price regulation plays an important role in South-eastern Europe. In this traditional hydrocarbon-producing region, almost 60% of the gas consumption is subjected to price regulation (e.g. in Romania). Overall, the Figure shows that the pattern remained stable: while hub-based pricing is still non-existent, the share of oil-indexed contracts slightly decreased from almost 50% to a bit over 40% in 2012.

The Figure also shows that oil indexation is still predominant in the Northern-Mediterranean countries. In 2005, all of the gas consumed in Greece, Italy, Portugal, Spain and Turkey was traded under long-term contracts. In this part of the continent, imports of crude-oil indexed imports from Algeria play an important role (e.g. in 2011, Italy imported 26 bcm of natural gas from Algeria, i.e. 37% of its total imports). Since 2005, the share of gas traded under gas-on-gas competition increased to over 10%. This development is probably due to the diversification of natural gas supplies enacted by some of the Mediterranean countries. Spain, for example, was largely dependent on Algerian gas supplies in the early 2000s. In recent years, this dependency has decreased with imports from Algeria accounting for only 40% of all imports (Honore 2011). At present, a major share of Spanish natural gas imports is LNG coming from Nigeria, Qatar, Egypt, Norway, and Trinidad.

**Opera pricing**

Opera pricing refers to the phenomenon that importers have to pay a higher price for their gas supplies the closer they are to Russia. Arguably, there are two main reasons for this. First of all, due to a lack of alternative supply sources (infrastructural constraints) many of the importing countries in Central Europe are in an unfavourable bargaining position. In addition, there is a lack of internal competition as the national gas markets are often dominated by one state-owned gas importing company.

---

Figure 26 illustrates the share of Russian gas in total gas consumption across EU Member States. For infrastructural and historical reasons, this share tends to be higher in Russia’s neighbouring countries (up to 100% in some Member States in Central and Eastern Europe, i.e. the Baltic States) and less important in Member States located closer to other traditional gas supply regions. It is worth noting that Russian gas is usually supplied under long-term, oil-indexed contracts.

**Figure 26: Share of Russian gas in overall gas consumption (2012 data)**


Figure 27 provides an overview of the wholesale prices of gas throughout the EU Member States. It is worth noting that the prices of gas in some of the “new” Member States are the highest in the EU, ranging from 34.2 €/MWh in Latvia up to 41.9 €/MWh in Bulgaria (EC 2013d).
As shown in Figure 27, the Baltic Member States and Bulgaria are still entirely dependent upon gas supplies coming from Russia. Hence, the prices of gas in these countries were related to long-term, oil-indexed contracts applied by Russian suppliers. Aiming at a diversification of gas supply, the members of the Visegrád Group⁵⁸ (V4) aim to implement the Gas Target Model by establishing a single gas trading area in the region, or to start the extraction of unconventional gas (e.g. in Poland). These efforts would strengthen the negotiating position of these countries towards their Russian suppliers, facilitating the renegotiation of long-term oil-indexed contracts.

⁵⁸ Czech Republic, Hungary, Poland, and Slovak Republic
It is also for the abovementioned reason, that some Member States aim at upgrading the existing network (construction of new interconnectors, and reversed flow stations) along with supporting the construction of new infrastructure (i.e. the completion of the Southern Gas Corridor, LNG terminals etc.).

2.3.6. Impact of oil price on natural gas prices

Natural gas prices can be influenced by the oil price directly or indirectly. Whenever the oil price is an integral constituent of the price formation mechanism, it has a direct influence. Given this definition, oil-indexation is the only direct impact. Where the oil price affects other parameters or boundary conditions influencing price formation, it has an indirect impact. Direct and indirect influences of the oil price on gas price are summarized below, describing the underlying mechanisms qualitatively.

Direct impacts

The oil price directly impacts natural gas prices whenever a long-term contract is indexed to the price of oil. In Europe, the share of these contracts is diminishing. More precisely, the share of oil-indexed contracts decreased from 75% in 2005 to 50% in 2012. While a number of European gas suppliers seem to be willing to at least tacitly accept hub-indexed contracts, there is still strong opposition, especially from Gazprom. The European Commission’s legal investigation of Gazprom’s practices may bring clarity in this regard. While oil-indexation is no longer relevant in the USA, Japanese LNG imports are generally indexed to the oil price.

As the existence of oil-indexed contracts largely depends on the suppliers’ preferences, and as suppliers vary across Europe, so does the impact that the oil price has on natural gas prices. The oil price is thus a particularly important price driver in Central and Eastern European countries, while it has hardly any direct impact in the UK and the Netherlands.

Those European (and world) regions whose contracts are still predominantly oil-indexed generally face higher prices for natural gas than areas with market pricing. Yet, there is reason to believe that the very same steps that these countries would need to take to enable hub-based pricing (i.e. better interconnecting their systems, domestic markets opened to competition, etc.) would also increase their bargaining position vis-à-vis their gas suppliers, and lead to more favourable terms on their long-term contracts. The continuing regional price differences in the EU thus cannot be solely attributed to the practice of oil-indexed contracts but will also be affected by e.g. the capacity and connectivity of the local gas infrastructure.

Lastly, oil-indexed contracts are not simply indexed to “the oil price”. In fact, pricing formulas vary widely, not only in terms of the share of a contract that is oil-indexed, but also vis-à-vis the oil price they are indexed to. While Russia prefers oil products, other European suppliers such as Algeria have traditionally preferred the price of crude oil.

As a result, the actual level of the direct oil price impact will be specific to each country or region, depending on the types and details of gas contracts used.

Indirect impacts

The indirect impact of the oil price is, by definition, harder to grasp and quantify. First of all, it is important to emphasise that the fundamental drivers of natural gas demand are frequently the same that also push up oil consumption. This includes crucial macroeconomic drivers such as population growth and the level of economic development, which generally lead to a stronger demand for both gas and oil.
There is also a crucial link with the economic cycle since both oil and gas demand decrease in times of economic crisis, as became evident in Europe in the aftermath of the 2008 financial and economic crisis.

In short, the fact that oil and gas prices are often correlated does not necessarily imply a causal link. Even if oil-indexed prices should completely vanish, one would still expect similar price trends for both energy commodities. Yet, there are at least five potential indirect impacts of the oil price that are worth mentioning.

First, there are areas where oil and gas are substitutes. While oil has dramatically lost its importance in the EU’s power system, in Malta and Cyprus it is still the fuel of choice. In addition, oil peaking units still exist in other Member States. Thus, a high oil price would increase the incentive to invest in gas-fired power generation in these countries, and consequently drive up gas demand. The same holds for the use of oil in heating, where high oil prices may accelerate the move to natural gas fired burners. In addition, natural gas may increasingly play a role in transport. Also here, the higher the oil price (relative to gas), the greater is the incentive to switch to natural gas in road (and maritime) transport.

Second, there is significant horizontal integration between the oil and gas industry as almost all major oil companies are also active in the natural gas business – and increasingly so. Thus, for example, if the upstream industry is enjoying significant revenue streams due to high oil prices, they are also endowed with the necessary financial resources to invest in the exploration and development of natural gas fields, leading to greater supplies in the medium/long-term. Conversely, in times of temporarily depressed oil prices, e.g. when there is an economic crisis, the oil and gas companies may postpone investments in new supplies due to a lack of resources.

Third, there is sometimes also a physical link between oil and gas production. This is the case for “associated gas”, which is a by-product of oil production. Hence, for instance, when oil prices are high enough to make the operation of a given oil well profitable, natural gas production from the same well will continue even if natural gas prices are very low, as in the aftermath of the US shale gas revolution. This is because in this case the production decision is based on the combined business case of both oil and gas. Whether this phenomenon increases or decreases gas prices depends on the circumstances.

Fourth, since oil is the fuel of choice for seaborne transportation, the oil price may also have an impact on LNG trade volumes. More to the point, as freight costs increase as a function of the oil price, LNG transportation costs do in principle, which leads to higher regional price differences in natural gas. However, LNG carriers have a wide range of different propulsion mechanisms. Most LNG vessels can burn fuel oil, boil-off gas or a blend of both in their engines and usually use the natural LNG boil-off as fuel as far as possible. As a result, the actual share of oil-induced transportation cost is small; varying strongly with the type of vessel and the way it is operated. The average heavy fuel oil share is 0.031 MJ per MJ of LNG at the point of use, resulting in an oil-price impact of less than 5% even if the costs are fully translated into the price.

Fifth, there is an empirical evidence for an inverse correlation between oil prices and exchange rates, i.e. that – ceteris paribus – an increasing oil price is accompanied by a falling dollar (see (IEA 2011)).

59 Natural boil-off occurs at a rate of approximately 0.15% of inventory per day and at times boil off is forced above this level to further reduce the fuel oil requirements.
As a result, all natural gas that is traded in US-$ would benefit from an increasing oil price, if it caused the dollar to fall (and if the gas contract is not linked to the oil price). While the correlation between the effective exchange rate and the oil price has been relatively strong in recent years, it has recently decreased (see Figure 28). It should be noted that the direction of causality is less evident. The relationship between the price of oil and the exchange rate could as well be reverse, i.e. oil prices being influenced by exchange rates. One argument for this direction of causality is based on the fact that oil is denominated in US-$. Therefore, a weaker dollar might lead to an increase in demand for oil in non-dollar economies, which would result in a rising oil price. The interactions between oil prices and the exchange rate are not fully understood. There is also some evidence that external factors such as the monetary policy might be influencing both quantities. In any case, if this negative correlation is here to stay, rising oil prices could make potential future shale LNG imports from the USA more attractive from an EU perspective.

**Figure 28: Development of the oil price and EUR/USD exchange rate (2000-2013)**

Source: (ECB 2013), (EIA 2013)

### 2.4. Steam coal

#### 2.4.1. Introduction

Together with oil and natural gas, coal is a leading primary energy globally, accounting for around 32% of global primary energy consumption (VDKI 2012) and around 40% of global electricity generation (IEO 2013). Coal is a heterogeneous product with different coal types based on different geological ages, heating values, content in volatile components and generally chemical composition including ashes, as well as physical properties, notably size
(Brandt 2000). Coal price indices for standardized coal qualities are provided for steam coal and coking coal.

Coal is transported by rail, road, and ship, depending on distance and available infrastructure, where generally ship transport is the most economical. Lignite, based on its lower heating value than hard coal, is usually transported only over very short distances, and consumed in dedicated power plants close to the mining area. Therefore, lignite trade is virtually non-existent. Production costs of lignite dominate its price, which is not affected by world energy markets (Panos 2009). Consequently, the following sections will focus on steam coal, where not indicated otherwise. Coal can be stored easily over long periods of time. An overview of the global coal market is provided in Annex B.

Compared to natural gas markets, coal markets are less in the scientific and political focus in Europe, but also globally. The level of publicly available analyses and data of coal markets is clearly lower for coal than for gas. Consequently, the analyses provided in this section, and the conclusions derived thereof, are less robust than those in the above section on gas.

Before discussing market fundamentals, various price formation mechanisms and showing the differences between EU Member States, a short overview on price trends is given. Finally, the main findings are summarised by presenting direct and indirect drivers impacting coal prices.

2.4.2. Price trends

A strong correlation between crude oil spot prices and coal import costs into Europe is visible in Figure 29 and in Figure 31.

Figure 29: Steam coal import costs into Europe and the USA

Statistical analysis gives a correlation coefficient of $r=0.82$ between the Brent spot price and EU steam coal import price until mid-2011 at 3 to 6 months delay.

Source: Study authors based on (BAFA 2013), (IEA 2013), (EIA 2013a), (Globalcoal 2013), (Eurostat 2013a)

61 Used for electricity generation.
62 Used for steel making. Hard coal includes both steam coal and coking coal.
For Germany the correlation is similar for the same period. However, using the available German coal data\textsuperscript{63} until early 2013 results in a somewhat lower correlation coefficient at $r=0.64$ at 3 months delay.

**Figure 30: Correlation of steam coal and natural gas prices in Europe, USA and Germany**

![Graph showing correlation of steam coal and natural gas prices](image)

**Source:** Study authors based on (BAFA 2013), (IEA 2013), (Eurostat 2013a), (IEA 2013f)

**Figure 31: Steam coal import cost correlation to Brent crude oil for EU and Germany**

![Graph showing steam coal import cost correlation to Brent crude oil](image)

**Source:** Study authors based on (IEA 2013a)

**Note:** Correlation at 4 and 3 months’ delay for EU and German import prices, respectively.

\textsuperscript{63} For this period EU import prices are not available from the IEA on a monthly or quarterly basis.
This lower correlation is a result of the recent coal price development. After a relatively high European coal price in the previous years it has been decreasing since the second half of 2011 while oil prices have rather stayed constant. In essence, coal prices have moved in parallel to oil prices between 2007 and 2011, while since mid-2011 they display different trends with coal prices declining and the oil price remaining constant.

Looking at the correlation between steam coal and natural gas gives a mixed picture (see Figure 30). For the USA, natural gas and steam coal import prices did not develop in parallel between 2007 and 2011. Rather, prices tended to develop into opposite directions. It has to be noted, though, that coal import prices for the USA are less relevant since imported quantities are small. For Europe and Germany, a strong correlation is visible between 2007 and the second half of 2011. The statistic correlation factor for this period is $r=0.92$ for Germany with an NG price delay of 2 months and at $r=0.90$ for Europe without delay. For the period 2007 to early 2013 the correlation factor for Germany is $r=0.82$ reflecting the growing decoupling of prices between late 2011 and today.

In summary, the correlation between oil price and steam coal price is strong, and the correlation between coal and gas prices is even stronger. However, the correlations of coal prices with oil and with gas prices have decreased since 2011.

The US steam coal import price stayed at constant low levels until mid 2008, and has only increased slightly since then until mid-2011. No correlations are found with crude oil prices.

2.4.3. Market fundamentals

Coal production and supply in the EU-27

Hard coal production in the EU-27 is declining (see Figure 32). In 2011, almost all producing EU Member States recorded declining production. A further decline in production is expected. Poland continues to be the largest producer in the EU-27 (VDKI 2012).

Figure 32: EU hard coal production

Coal is an important source of energy in the European Union, representing 19% of primary energy supply in 2012 up from 16% in 2011 as a result of decreasing coal and CO$_2$ emission prices (VDKI 2013); it had a 25% share in electricity generation in 2010. However, there are big differences between European countries: Poland, for example, produces more than 90% of its electricity from coal, while Lithuania’s and France’s electricity supply rely to less than 5% on coal (see Section 2.5 Electricity).
As a general long-term trend, coal consumption in the EU-27 has decreased over the last two decades (see Figure 33). However, since 2009 consumption has been increasing. Largest coal importers in the EU-27 are the UK and Germany, followed by Spain and Italy.

**Figure 33: Hard coal gross inland consumption**

![Image of coal consumption graph](image)

**Source:** Study authors based on (Eurostat 2013d)

Currently, the biggest steam coal exporters to Europe are the USA, Colombia, and Russia, together covering 70% of EU imports. Australia and Indonesia play minor roles for Europe, although they are the largest exporters globally. This structure has changed over the past years. South Africa and the Ukraine, who used to be the main sources of coal a few years ago, have become less important for the EU; Russia’s importance has declined somewhat. At the same time, US coal imports to Europe have increased by 85% between 2007 and 2012 representing 19% of the EU-27 imports in 2012 (Eurostat 2013d), and coal trade from Colombia to the USA have decreased with the quantities redirected towards Europe (VDKI 2012), (VDKI 2013).

### 2.4.4. Price formation mechanisms

#### Typical contracts

The physical coal market is dominated by OTC (over-the-counter) trade. Contracts are concluded directly between producers and (large) clients. Transparency of the market is limited as trade structures are to a significant extent bilateral\(^{64}\). For steam coal, trade platforms such as globalCoal as well as commodity markets with dedicated brokers have been established. Spot market trade is increasing in quantities and relevance. In order to secure required quantities, contracts often have durations of 5 to 10 years. Prices are flexible and are typically adjusted on an annual basis based on spot market prices. Global competition is limited by transport costs (Ströbele et al. 2012), (Erdmann et al. 2010), (Panos 2009), (Ritschel et al. 2007). “Particularly in the global steam coal trade a trend towards more spot deals (3-6 months and less) can be recognized.” (Schernikau 2010)

---

\(^{64}\) In the European Union, the EMIR (European Market Infrastructure Regulation) and REMIT (Regulation on Energy Market Integrity and Transparency) regulations aim at increasing transparency. As an international example, the “Government of the Russian Federation approved an order to include coal in the list of exchange commodities, off-exchange transactions with which, including long-term supply contracts, are subject to mandatory registration by exchanges. From 20th July 2012, all coal producers, whose groups of persons sold over one million tons of coal in the preceding year, must register all off-exchange transactions with [hard] coal […]. Introduction of coal transaction registration will ensure transparent pricing on relevant markets.” Federal Antimonopoly Service of the Russian Federation, press release, 3 August 2012, [http://en.fas.gov.ru/news/news_32393.html](http://en.fas.gov.ru/news/news_32393.html).
Coal indices and derivatives trading

As coal qualities and places of delivery vary, price indices have been established on the basis of standards for quality, place of delivery and delivery conditions. An important coal price index for Europe is the MCIS (McCloskey Coal Industry Services) index for North-West-Europe (NWE). It describes CIF (cost, insurance, freight) prices for delivery to ARA (Amsterdam, Rotterdam, Antwerp) ports. Another important coal price index for Europe is the globalCoal DES ARA index, also based on delivery to ARA ports.

"The coal market is developing rapidly into a commodity market. More and more transactions are based on coal indices. In 2011, derivatives trade reached the 8-fold volume of physical trade in Europe." (HMS 2013)

The importance of price indices for the coal market is underlined by the fact that the German coal import prices follow the DES ARA price index closely, albeit with an offset and with a delay of up to three months (see section 2.4.1).

In spite of generally increasing derivatives trading in Europe and the USA, coal futures trading at the German EEX exchange (European Energy Exchange), established in 2006, practically ceased in 2012. According to EEX own assessment, this is based on a general trend towards off-exchange trade platforms (EEX 2012); see also Table 3 displaying EEX traded coal volumes between 2005 and 2012.

Table 3: Coal futures volumes traded at EEX starting in 2006

<table>
<thead>
<tr>
<th></th>
<th>2005</th>
<th>2006</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
</tr>
</thead>
<tbody>
<tr>
<td>Volume of coal</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>traded [1,000 t]</td>
<td>0</td>
<td>1949</td>
<td>246</td>
<td>246</td>
<td>117</td>
<td>1350</td>
<td>420</td>
<td>0</td>
</tr>
</tbody>
</table>

Source: (EEX 2005-2012)

Price components

Coal prices are determined by (Schernikau 2010):

- Short-term marginal FOB (free on board) costs and supply/demand equilibrium
- CO₂ emission prices
- Sea transport prices.

These factors are analysed in detail below.

Marginal FOB costs and supply/demand equilibrium

Marginal FOB costs include as major elements:

- Coal extraction costs,
- Inland transport/transshipment costs, and
- Port handling costs.

The marginal FOB cost curve, or cash-cost curve, defines the global coal price where it intersects with the demand curve (see below for more details).

---

65 The DES ARA Index is calculated based on firm bids and offers as well as transactions which are executed via the globalCOAL online trading platform. https://www.globalcoal.com/docs/ARAIndexMethodologyV1e.pdf
66 Translation from German by M. Altmann
Table 4 details the cost structure (CIF – cost, insurance, and freight) of coal delivered to ARA (Amsterdam Rotterdam Antwerp) ports for 2006/7.

**Table 4: Cost structure of coal (2006/07) CIF ARA (US$ per ton)**

<table>
<thead>
<tr>
<th>Exporting Country</th>
<th>Region Production method</th>
<th>Cost free mine</th>
<th>Inland transport</th>
<th>Port handling</th>
<th>Sea freight Ø 2006</th>
<th>Total CIF ARA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Australia</td>
<td>Queensland open-cast mining</td>
<td>14-42</td>
<td>6-14</td>
<td>2-3</td>
<td>22</td>
<td>44-81</td>
</tr>
<tr>
<td></td>
<td>New South Wales deep mining</td>
<td>25-40</td>
<td>3-10</td>
<td>2-3</td>
<td>26</td>
<td>56-79</td>
</tr>
<tr>
<td></td>
<td>New South Wales open-cast mining</td>
<td>22-38</td>
<td>3-10</td>
<td>2-3</td>
<td>26</td>
<td>53-77</td>
</tr>
<tr>
<td>South Africa</td>
<td>open-cast mining</td>
<td>16-38</td>
<td>6-10</td>
<td>1.5-2</td>
<td>16</td>
<td>38-56</td>
</tr>
<tr>
<td>Columbia</td>
<td>open-cast mining</td>
<td>22-26</td>
<td>2-3</td>
<td>3-5</td>
<td>15</td>
<td>42-49</td>
</tr>
<tr>
<td>Russia</td>
<td>open-cast mining partially plus transit/treatment</td>
<td>16-20</td>
<td>24-26</td>
<td>2-3</td>
<td>14</td>
<td>56-63</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>(6-8)</td>
<td>(60-68)</td>
</tr>
<tr>
<td>Indonesia</td>
<td>open-cast mining</td>
<td>16-33</td>
<td>2-7</td>
<td>2-4.5</td>
<td>17</td>
<td>37-61.5</td>
</tr>
<tr>
<td>Venezuela</td>
<td>open-cast mining</td>
<td>18-22</td>
<td>7-9</td>
<td>3-5</td>
<td>19</td>
<td>47-53</td>
</tr>
</tbody>
</table>

**Source:** Study authors based on (Ritschel et al. 2007)

The relative importance of the different cost elements varies depending on the local circumstances. Production costs at the mine vary considerably based on geological and other local factors, and have increased significantly since 2006 (see below). Inland transport varies notably depending on available infrastructure and transport distance, with Russia clearly reflecting the long rail transport distances to sea ports in the inland transport costs. Port handling has a relatively small contribution to overall costs. Sea freight again strongly depends on transport distance, with longest distances from Australia to Europe, and shortest distances to Europe from South America67. The major cost elements are discussed below, including their development over time.

Figure 34 details the marginal costs of coal production by supply countries. South Africa and Indonesia are the cheapest producers; however, (VDKI 2013) emphasises that cash costs68 of coal production in Indonesia have drastically increased from US$26/t in 2006 to US$52/t in 2012. This is reflected in Figure 34 by three marginal cost levels for the country from US$45/t to US$70/t, and is supported by the older marginal cost curve for 2006 (see Figure 35). It is important to note here that the marginal FOB costs have increased significantly in general over the past six years.

Several reasons are put forward to explain this cost increase, including labour costs, machinery costs, operation and maintenance costs, as well as exchange rates to US dollars. Revenues on international markets are generally generated in US dollars, while costs are mainly generated in national currencies.

---

67 The low sea freight costs from Indonesia cannot be explained by transport distance.
68 Cash costs and marginal costs are taken to be the same. “FOB (free on board) cash cost includes mining costs, costs of coal washing and preparation, inland transport, mine overhead as well as port charges (this definition corresponds to the C1-cash cost definition widely used in the mining industry). It excludes royalties and taxes, as well as seaborne shipping costs.” (IEA 2013b).
Thus, whenever the US dollar is devalued, revenues in national currency decrease, or put inversely, cash costs in US dollars increase (IEA 2013b). However, whenever the US dollar is upvalued, revenues increase in national currency, or cash costs decrease in US dollars. Taking the example of the Indonesian rupiah, the exchange rates to the US dollar in 2007 and in 2012 were identical, and thus the exchange rate did not change the cash costs. For Australia, however, the US dollar was upvalued compared to the Australian dollar by some 20% in this time frame, which lowered the Australian cash costs accordingly. Obviously, there is no exchange rate effect for US producers, which are currently price setting as discussed below.

Increasing fuel prices are also an important aspect in this context. According to (Schernikau 2010), in 2006 30-40% of all surface mining costs were fuel costs. It can be assumed that this was almost exclusively based on oil products as most machines are powered by oil products, and truck transport is an important element of surface mining. Mining in turn accounts for 40% of FOB costs, while 44% are inland transport and 16% are transshipment costs. Inland transport is carried out by rail where possible, e.g. in Russia, which may be electric or diesel-based, or it is done by truck, e.g. in Indonesia. Inland transport is a very important cost element notably in Russia, where both transport routes to the Baltic and to the Pacific are very long.

As a rough estimate, 33% of FOB costs in 2006 were based on the price of oil products: 14% from fuel consumption in coal extraction, 11% from inland transportation (assuming 25% of inland transportation costs to be fuel based), and 8% from transshipment (assuming 50% of transshipment costs to be fuel based). Average 2006 FOB costs were around US-$30/t. With the above estimate of roughly one third of that based on oil product prices, which have been increasing by around 80% since 200670, FOB costs should have increased by around US-$8/t alone by the increase of oil prices. However, average FOB costs have roughly doubled from US-$30/t to US-$60/t if demand is taken as constant for the sake of comparability71. Thus, oil price increases would account for roughly 25% of cost increases based on the above rough estimate. Unfortunately, no analysis of this relation has yet been published. A detailed analysis of this aspect is beyond the scope of the present study.

Finally, geological conditions are becoming more and more difficult as easy deposits are generally exploited first. Seam thickness is decreasing, while top layer thickness in open cast mining or depth of deposit in underground mining are increasing, quality is deteriorating etc. In detail, this is not true in all individual cases as exploration is not as systematic and detailed for coal as e.g. for oil, but the general trend is clearly identifiable. For the longer-term future, this means that not all resources identified will be converted into exploitable reserves as (Höök et al. 2010) point out: “From a simple survey of reserve and resource assessments for almost a century, and a more detailed examination over the last three decades, it can also be found that estimates are of poor quality. Resources have undergone significant changes, mostly downward. The recent increase reported by the BGR72 […] should be seen as speculative instead of definite.

In addition, it is clear that the (assumption or premise) of having coal resources unequivocally converted to reserves does not seem to be supported by published data on a global level. It is recommended that more comprehensive analyses of global coal resources and how they can [be] converted to reserves are pursued […]. Obtaining a realistic picture

---

69 Transshipment is transport in smaller ships to coal export terminals where coal is loaded onto large carriers.
70 In nominal US- $ terms
71 Based on increasing demand, the marginal cost supplier has higher costs than that as shown below.
72 German Federal Institute for Geosciences and Natural Resources (Bundesanstalt für Geowissenschaften und Rohstoffe), an authority of the German Federal Ministry of Economics and Technology
of the future potential for coal resource to be upgraded to economically competitive reserves is needed [...]."

Taking a longer term view, (Zellou and Cuddington 2012) similarly argue that “(l)ong-term trends for crude oil suggest that increasing economic scarcity is indeed an issue. For coal, however, this does not seem to be the case [...]”. On the other hand, the 1980ies have shown that coal prices may be substantially higher than they are today. The short-term trend of marginal coal production costs over the past six years provides indications that factors for increasing costs include an increasing share of coal production from smaller and more difficult to exploit coal deposits, a sign of beginning scarcity.

The coal price is set by the intersection of the demand and the marginal supply cost curve. Australia and North America currently set the FOB price for coal according to the cash cost curve shown in Figure 34, which assumes a price independent demand curve. This simplification does not change the general picture of the importance of the marginal supply cost curve.

**Figure 34:** Coal supply FOB cash cost curve for internationally traded steam coal in 2010/2011

![Coal supply FOB cash cost curve for internationally traded steam coal in 2010/2011](image)

**Source:** Study authors based on (euracoal 2011) and (uscoalexports 2013)

**Notes:** PRB – Powder River Basin

Global FOB marginal cost analyses are very limited and only carried out irregularly. Among the recent independent analyses are (Baruya 2007), (Ritschel et al. 2007) and (Schernikau 2010). Very recently, the IEA included a cash cost curve in its World Energy Outlook 2013 (IEA 2013b), which is less steep than the curve in Figure 34.

According to IEA, cash costs of the cheapest producers are higher than in Figure 34, while cash costs of the most expensive producers are around 20% cheaper. In the detailed assessment of cash costs by country, the IEA comes to significantly different results than displayed in Figure 34. The cash cost curve presented in IEA’s World Energy Outlook 2012
(IEA 2012e) is much less detailed, and only reaches 660 million tons on the horizontal axis compared to 850 million tons in 2013. Thus, the understanding of this important element of price formation is limited as is the reliability of the results derived thereof.

**Figure 35: Coal supply FOB marginal cost curve by country in 2006**

![Coal supply FOB marginal cost curve by country in 2006](image)

**Source:** Study authors based on (Schernikau 2010)

Cash cost analyses are used to model global coal markets in an attempt to project future quantities, global trade flows and prices. As an example, two dedicated coal models, (COALMOD (Haftendorn 2012) and WorldCoal (Schernikau 2010)), and a general energy model (PRIMES used by research groups under contract of the European Commission) are compared in Figure 36 with actual prices. An interesting PRIMES modelling was carried out in 2006 with the dedicated objective of exploring the effects of “soaring oil and gas prices” (E3M 2006). It is important to note that (E3M 2006) calculates that coal prices essentially remain at low levels even if oil and gas prices increase significantly, indicating that the model does not find a strong impact of the oil price on coal prices. Similarly, COALMOD does not find significant price increases until 2030. WorldCoal, however, projects strongly increasing coal prices until 2015, based on increasing costs and market power of players (see also below). Unlike COALMOD and PRIMES 2006 projections, actual coal prices increased significantly after 2006. PRIMES 2011 (EC 2011) projections in the framework of the Impact Assessment for the Roadmap 2050 include three scenarios developing significant price spreads between the scenarios over time.

This example of future projections shows the uncertainties of the models and the underlying data. Experts notably point out that the reliability of the basis used for modelling coal markets, namely the detailed marginal cost data, is rather weak.

---

73 PRIMES relies on the POLES model for future energy price projections.
74 Only 2006 and 2015 results are provided, values for other years are not available in (Schernikau 2010).
Figure 36: Comparison of future coal price projections with actual coal prices

![Graph showing comparison of future coal price projections with actual coal prices.](image)

Source: Study authors based on (Haftendorn 2012), (Schernikau 2010), (E3M 2006), (EC 2011)

**CO2 emission prices**

EU Allowance (EUA) prices\(^{75}\) have an indirect influence on coal prices through the possible substitution of coal by natural gas in electricity generation. At high EUA prices, gas may substitute coal in power production, thereby reducing demand for coal. In the current situation of relatively high gas prices in Europe, decreasing coal prices, and very low EUA prices, gas is substituted by coal in electricity generation to a large extent (see section 2.5) (Ritschel et al. 2007). Thus, CO2 emission prices have an effect on demand, which through the marginal cost curve discussed above influences the price.

**Sea transport prices**

90% of international coal transport is carried out by ships of the following types: Handysize: 40,000–60,000 t, Panamax: 60,000–80,000 t, and Capesize: above 80,000 t.

The Baltic Dry Index (BDI) is an important price index for global bulk freight (mainly coal, iron ore, and grain) on standard routes (see Figure 37). It has been published on a daily basis since 1985 by the Baltic Exchange in London. The index displays very strong fluctuations over the 2007-2013 period\(^{76}\). At present, it is at its lowest level since 1986 (VDKI 2012).

---

\(^{75}\) One EU allowance (EUA) allows emitting one ton of CO2. EUAs are traded in the framework of the European Union Emission Trading System (ETS).

\(^{76}\) In general, the BDI measures the demand for bulk shipping capacity versus the supply of dry bulk carriers. As shipping capacity does not change quickly (it takes about two years to build a new ship and it is too expensive to temporarily take them out of service) it is a very sensitive indicator for bulk shipping demand.
Figure 37: Global bulk freight index BDI

Source: Study authors based on (capitallink 2013)

Figure 38 confirms these patterns specifically for coal transport on major coal transport routes. Freight prices culminated in 2008 at maximum levels of US$60/t from Colombia to Europe, and of above US$80/t from Australia. Freight prices went down significantly in 2008/09, increased again somewhat in 2009/10 and have decreased since then to very low levels.

Figure 38: Development of hard coal (spot) freight prices (Capsize) between 2002 and 2013 to the ARA ports (in US$/t)

Source: (VDKI 2013)

“This is above all a consequence of the surplus capacity in ships. In the meantime, the overcapacity has reached such a high level that cargo volumes would not be able to utilize full capacity even if economic growth were robust.” (VDKI 2012)

As shown in Figure 39 (for details of the calculation see Annex C), heavy fuel oil (HFO), also called bunker fuel, prices following crude oil prices produced a peak in fuel costs in 2008 with a subsequent decline in 2009. Since 2010, fuel costs have been steadily increasing to top the 2008 peak. Thus, fuel costs have been showing the inverse trend of freight prices since 2010 as displayed in Figure 37 and Figure 38 with freight prices going down and fuel costs going up. In 2011, fuel costs from Colombia to Europe reached €6.51/t to €8.40/t, or around US$9/t to US$12/t.
Thus, while at the peak in 2008, fuel costs only accounted for around 20% of freight prices from Colombia, on a roundtrip basis, fuel costs are currently close to freight prices. In such a situation, ship owners react by reducing ship speeds (thereby increasing shipping times) to save on fuel consumption.

**Figure 39: Fuel costs for the shipping of one ton of coal from Newport News, USA, or from Cienaga, Colombia, to Rotterdam**

Source: Study authors  
Notes: Min and max values are based on minimum and maximum prices for HFO in each year

Based on data for 2001-2009, (Zaklan et al. 2012) conclude that “coal prices and freight rates are not directly related to oil price”, which confirms the above finding that freight costs are not correlated to (oil-based) fuel costs for transport.

However, with freight costs being a significant but fluctuating price component at the consumer location, there is no single world market price. Rather, ideal market prices are differentiated regionally for all suppliers and all consumers. Regional prices may be higher than the CIF costs of the marginal supplier for that region, as suppliers may have opportunity costs by not delivering to another consumer (Schernikau 2010).

**Market power**

In perfectly competitive markets, the market price is set by the marginal cost of the supplier with highest marginal costs necessary to satisfy demand. “Short-term price fluctuations may, however, cause coal prices to fall below marginal FOB costs for brief periods of time.” (Schernikau 2010). Current coal prices in Europe are below marginal FOB costs shown in Figure 34. This view is confirmed by experts interviewed for this study. Based on high coal prices between 2008 and 2011, investments have been high in coal production with resulting overcapacities in spite of growing demand. Thus, prices are expected to remain at the current low level for some time to come, or may even decrease somewhat more. However, they are expected to eventually go back to sustainable levels and increase further. The relevant timeframe is difficult to assess, but should be within the coming two years.

Unsustainably low international freight rates, which have approached the level of the pure fuel costs, are also expected to increase again in a similar timeframe, adding to the expected FOB cost increases.
The fact that prices are currently below marginal costs of the price setting supplier, indicates very strong competition. Based on 2005 and 2006 market data, (Haftendorn, Holz 2010) conclude: “Our chief finding is that [...] the simulation of perfect competition better fits the observed real market flows and prices.” However, there are numerous hints at market imperfections. Coal markets are much less transparent than for example oil markets because of the significant volumes in bilateral and other OTC trades. (Schernikau 2010) emphasises that the top five coal mining companies account for almost one third of global hard coal exports. “In fact, the five major steam coal exporters [...] account either directly or indirectly through marketing agreements for over 80% of Colombian and South African exports, for over 60% of Australian exports, and for about 40% of Russian and Indonesian exports.”

With respect to the question of whether nations act as strategic players in the coal market, (Paulus et al. 2011) come to the conclusion: “We find that trade and prices of a China-Indonesia duopoly fit the real market outcome best and that real Chinese export quotas in 2008 were consistent with simulated exports under a Cournot-Nash strategy.”

Thus, there are indications that both private companies and certain countries have market power. This in general leads to higher prices than in perfect competition.

The price development in 2008 with strongly increasing prices until mid-year, and a subsequent dramatic price drop is difficult to explain with perfect competition. (Trüby, Paulus 2012) analysing this issue conclude “that either unknown capacity bottlenecks or more sophisticated non-competitive strategies were the cause for the high prices in 2008.” The European Commission puts it in clear words: “The spot price levels seen in mid-2008 were completely unprecedented in international coal markets and bore no relationship to underlying costs of production and transportation. Prices to North-West Europe reached $219.35 on 4th July 2008.” (EC 2010). Other experts put forward a coincidence of unrelated aspect to at least partly explain this extreme price development. (Baruya 2011) identifies a “triple supply shock and freight shortage:

- Coal demand in China soars; exports stop; winter weather causes demand spike
- Record flooding in Queensland (Australia)
- South African power cuts
- Freight averages 30 $/t (max. 60 $/t)”.

This indicates that the fact of China turning from a net exporter to a net importer of coal with significant quantities (see Annex B for more details) between 2006 and 2009 had a noticeable effect on the global market. In this context, it is noteworthy that less than 15% of global coal consumption is covered by exports/imports.

Thus, a combination of demand development (notably China), freight price development and short-term supply disruptions caused the 2008 price spike. However, the very quick and deep fall of prices after the spike in mid-2008 more than halving the price within two quarters indicates that the extreme price increase and decrease must have had drivers beyond generally accepted price building mechanisms. The influence of the oil price through marginal cost developments would in general not be fast enough to explain this dynamic.

77 In a monopoly market, the market price is highest while in perfect competition the price is lowest. In different imperfect competition situations, of which the Cournot-Nash competition is one, prices are between the two extremes.
2.4.5. Regional differences in the EU

Figure 40 shows the quarterly average steam coal import prices in various European countries. Only minor regional differences are visible with respect to volatility and the time lag to crude oil prices. Price levels show regional differences of up to about 20 €/t (see Figure 41).

Coal import prices of different EU Member States as displayed in Figure 40 show very similar overall patterns, although price differences exist. Italy and France show generally higher coal import prices than Germany or the UK, while Finland and Spain mostly have lower import prices. The ARA index\(^78\) shows significantly higher values than the EU average before the price peak in 2008, while thereafter it shows significantly lower values than EU average until the end of 2009. Since then, the ARA index is close to average EU import prices until the mid-2011 when IEA data end. Until including the first quarter of 2013, the EU ARA index is very close to the German import prices.

Figure 40: Steam coal import prices in European countries

Source: Study authors based on (EIA 2013a), (IEA 2013), (Globalcoal 2013), (Eurostat 2013a)

The price of coal import into Northern EU Member States adds the transport costs from the ARA ports to the Member State border to the CIF ARA price. Alternative transport routes exist for the different Member States. For Germany as an example, coal can be transported directly from export terminals to Hamburg port. However, draught restrictions in Hamburg limit the ship size, and thus increase transport costs. Furthermore, costs for transport from the border to the consumer (in general a power plant) are also relevant for the consumer, but are not reflected in the import costs. Inner-European transport is mainly carried out by ship (seagoing or inland water vessel), or by rail, which is generally more expensive (Panos 2009).

\(^78\) The DES ARA Index for the price of thermal coal delivered at the ports of Amsterdam, Rotterdam, or Antwerp (ARA) is calculated based on firm bids and offers as well as transactions which are executed via the globalCOAL online trading platform. https://www.globalcoal.com/docs/ARAIindexMethodologyV1e.pdf.
Mediterranean Member States import coal directly from export countries. Port sizes and draught limits are factors leading to varying import costs. Also, import quantities are a cost element. Italy and France with relatively high import costs import lower coal quantities than Germany and the UK with relatively lower costs. Spain and Finland, however, have below-average coal import costs in spite of lower quantities. Coal qualities are another relevant factor. Depending on the power plant technology, some plants can only burn specific coal qualities while others can use "any-coal". In general, the tendency towards "any-coal" plants is stronger in markets with strong competition.

The structure of coal origins for the 10 selected Member States is shown in Figure 42. It shows that most countries have a relatively diversified import structure. This is in general not cost optimal, but has strategic reasons and may also be based on long-term supply structures. It is rather astonishing, from a cost perspective, to see imports of Australian coal with rather high marginal costs and the longest transport distance to Northern Europe. However, (IEA 2013d) shows major Australian and US FOB export price discrimination, depending on the destination country. As an example, in 2009, Australian FOB prices were US-$67.68/t with destination France, while they were US-$44.47/t, or 34% lower for Spain. Total quantities, however, were rather similar. These examples show that import cost differences depend on many factors and are difficult to explain.
The coal market in Poland

In the current debate on energy and energy policies, Poland is frequently associated with shale gas. However, while shale gas may dominate the political debate, coal still dominates the Polish energy mix (particularly power generation) with the country being the EU’s largest producer of hard coal. Among all European Member States, Poland’s energy industry is the most reliant on coal. Roughly 85% of electricity produced in Poland comes from coal-fired power plants (further explained below). Therefore, this case analysis is interesting in order to assess the impact of oil prices on coal prices on a Member State level.

Supply

In 2011, approximately 138 million tonnes (Mt) of coal were produced in Poland, 55% of which was hard coal and 45% lignite/brown coal. With an annual production of 76 Mt, Poland was the biggest producer of hard coal in the EU in 2011. However, falling exports of hard coal (~35% in 2011 compared to 2010) widened the country’s trade deficit in the coal sector. In order to satisfy its domestic consumption, Poland imported approximately 15 Mt of hard coal (almost half of it from Russia) worth 1.5 bn €. The value of coal imports increased by 15.4% compared to 2010 and by 40% compared to 2008. Hard coal imports mainly originated from Russia (7 Mt) and the Czech Republic (2 Mt). Smaller amounts were imported from Ukraine, the US, Colombia, and Kazakhstan. The traded volumes of lignite/brown coal remained marginal as its transport over long distances is uneconomic.
**Demand**

In 2011, Poland consumed 146 Mt of coal. Hard coal accounted for 57% of the consumption, whereas lignite/brown coal had a share of 43%. While the mined volumes of lignite/brown coal were almost entirely combusted in plants located in close proximity to the extraction sites (for heat and power generation), hard coal was consumed in a variety of sectors. The majority of hard coal was used by the power sector (54%), followed by the industry (29%) and the household sector (12%). The remaining volumes (5%) were consumed in other sectors such as transport and agriculture.

In Poland, the production of electricity is largely based on coal. In 2011, Polish power plants produced 163,548 GWh of electricity. As shown in Figure 43, 85% of this volume was generated through hard coal and lignite combustion, followed by various types of renewable energy sources (RES) (8%), natural gas (4%), and other fuels such as oil or liquefied natural gas (3%).

**Figure 43: Poland – Electricity generation by type of fuel (2011)**

![Pie chart showing electricity generation by type of fuel in Poland in 2011.](image)


**The coal market in Poland**

In Poland, coal is traded on a direct bilateral basis between suppliers and consumers or brokers. The duration of coal supply contracts between producers and electric utilities or industrial consumers usually ranges from two to five years. The price of coal is subject to negotiation between the parties. It is driven by a multiplicity of factors related to its quality (i.e. calorific value; sulphur, nitrogen, and moisture levels). Usually, these quality parameters are precisely defined in coal contracts. If contracted coal supplies do not fulfil the quality parameters defined in a contract, the buyer can either (i) refuse the shipments, or (ii) try to renegotiate their price. Depending on the type of freight, transport costs can represent a large share of the final price of coal. In 2006, transport costs accounted for over 30% of the final price of domestically produced coal stored in Polish harbours. For this reason, transport is also subjected to negotiations between the parties. Some buyers prefer to take care of transport themselves, believing that they can negotiate better deals with freight companies. Domestic prices of coal are also determined by international markets, i.e. by the prices of coal in Polish harbours.
Depending on the size of the ships, these prices are usually US$6–10/t higher than in the ARA ports. As prices of coal tend to decline on the international markets, coal producers operating in Poland have to face downward pressure from their consumers who are demanding lower prices for coal mined domestically.

**The future of coal in Poland**

The share of coal in electricity generation in Poland is expected to decline in the coming years. However, it might remain robust. In 2011, the Polish Ministry of Economy presented a document entitled “Energy Mix 2050: an Analysis of Scenarios for Poland”, outlining the possible structure of the Polish energy mix in 2050. According to different scenarios (e.g. including a large scale deployment of electric cars and CCS technologies), the share of coal in power generation is expected to range between 21% and 32%.

### 2.4.6. Impact of oil price on coal prices

#### Direct impacts

Oil products are used in coal transport and extraction. As a result, they potentially provide for relevant impacts of the oil price on coal production costs and thus on FOB costs through their strong dependence on the oil price. Increased FOB costs translate into coal prices through the marginal cost curve. As shown above, international sea freight prices, however, do not show any correlation to oil product prices, even though fuel costs are an important share of marginal freight costs.

While no detailed analysis has been made to date on the impact of fuel costs on marginal FOB coal costs, a rough estimate shows that they are a relevant element of FOB costs, and an impact may be expected. However, other factors such as labour costs, machinery costs, or operation and maintenance costs are important cost elements as well and have increased significantly in recent years. The development of exchange rates between national currencies in extracting countries and the US dollar as the main currency on the international markets also plays a role.

Due to high coal prices between 2008 and 2011, investments have been high in coal production with resulting overcapacities in spite of growing demand. As a result, international coal prices are currently below marginal FOB costs of some producers, and this situation is expected to prevail for some time to come. However, coal prices should eventually go back to sustainable levels and increase further.

#### Indirect impacts

Some decades ago, oil products were an important element of electricity generation (see Figure 18). The resulting substitution potential between oil and coal provided for a significant element of the oil price impact on coal prices. However, with the share of oil decreasing in electricity generation to the very low levels of today in Europe and globally (see also section 2.5), this impact is reduced to a minimum, and does not play a role in coal pricing mechanisms any more with the exception of specific cases such as Cyprus and Malta. The strong correlation between oil and coal prices must therefore be based on other factors.

Instead, natural gas has become an important fuel for electricity generation alongside coal, which provides for a significant substitution potential between gas and coal. Substituting gas by coal in electricity generation increases coal demand, which is translated into increasing prices through the marginal cost curve. With the oil indexed long-term gas contracts this was a mechanism for oil price to impact coal prices. However, the currently
decreasing coal price in Europe at a time of increasing oil price shows that this impact is weak at the moment.

Slowly decreasing levels of oil indexation in gas pricing may have a certain influence here. However, the main reasons should be in the overcapacities in global coal mining and the constraints to the substitution of gas by coal. While dispatching of existing gas or coal fired power plants allows for quick reactions of the market to changing fuel prices, the construction of new power plants requires a lead time of typically five or more years. Moreover, in many countries there is growing public resistance to the more greenhouse gas emitting coal power plants, and emission trading favours the less CO₂ intensive gas over coal depending on prices for emission allowances.

Another relevant aspect in coal pricing in relation to oil price is the role of the oil price as a good indicator of economic activity. Therefore, players in coal production, trading and consumption take it to indicate increasing or decreasing economic activity which in turn affects demand for coal. Oil spot price is a much quicker indicator than statistics or economic indices.

Finally, the psychological element of the oil price is still relevant, though with decreasing trend. “Coal price cannot decrease when oil is increasing” is still a relatively widespread reaction in the market. However, if coal fundamentals do not support such a development, the coal market reacts to the fundamentals very quickly as can be seen by recent market developments.

Conclusion
As a conclusion, the direct impact of the oil price on coal prices through fuel costs in coal extraction and inland transport to export terminals is limited. Indirect impacts present in the past have largely vanished or strongly decreased in importance.

Using a quote from Schernikau 2010, an “[...] apparent correlation between these two energy fuels [coal and oil] in rising markets is misleading. Most raw material prices, especially prices for energy raw materials, increased dramatically in 2007 and 2008. Thus, if we were to analyse this time period we would find correlations between many products that have little or no real impact on each other.”

This indicates that correlations between the oil price and coal prices are to a large extent not based on a cause and effect relationship, but that underlying price drivers for both are similar, most notably economic development. In fact, a decoupling of coal prices from oil and gas prices has been observed since 2011 (DG Energy, Market Observatory for Energy, 2013).

2.5. Electricity

2.5.1. Introduction

In contrast to the primary energy sources oil, natural gas, coal, uranium, bioenergy, solar radiation, or wind, electricity is a secondary energy carrier that can be produced from fossil, nuclear, or renewable primary energies.

Electricity is in general supplied to the consumers without offering different qualities. Nonetheless, electricity is supplied on different voltage levels, and with limitations on the usable power, depending on the voltage level and on the contract.

---

79 Economic activity determines transport volume; transport is to a very large extent dependent on oil products; consequently, increased economic activity results in an increasing demand for oil products.
Transport and distribution
In general, electricity is transported and distributed in Europe through an electricity grid. Only very small quantities of electricity are supplied through off-grid applications. In order to maintain grid stability, electricity generation and demand need to be balanced at any given time.

Electricity storage
Contrary to oil, gas, or coal, electricity storage is in general not trivial for both technical and economic reasons. Electricity storage in quantities relevant to wholesale markets has so far only been commercially viable by pumped hydro power plants\(^80\). The current power rating of such storage in so-called “Eurelectric Europe”\(^81\) is around 35 GW\(^82\) in generation mode, equivalent to some 4% of total installed power plant capacity in the EU-27, allowing to store some 2.5 TWh of electric energy in one ideal storage cycle (Eurelectric 2011). Pumped hydro is generally well-developed in Europe with strong variations between countries based on topology, and additional potentials are limited vis-à-vis renewable energy capacities in the long term (Altmann et al. 2012). Realisable potentials for new pumped capacities in the EU have recently been assessed by (JRC 2013) at ten times the currently installed capacities in the most optimistic scenarios; in the more restrictive scenarios, potentials go down to doubling the current capacities. Significant potentials outside the EU are available in Norway and Turkey.

All the above features differentiate electricity markets significantly from other energy markets such as oil, natural gas, or coal.

2.5.2. Price trends
Wholesale electricity prices show strong variability over time and significant differences between national or regional markets. Being a secondary energy carrier that can be produced using different technologies and based on a large variety of primary energies, the marginal cost of electricity generation largely depends on the prices of the primary energies used for its generation\(^83\). For most renewable energy technologies, primary energy is free of charge, notably solar irradiation and wind, but also for hydro, geothermal, or ocean energies. It is thus interesting to analyse electricity price trends, and correlations thereof with primary energies such as oil and gas.

The Pan European Power Index (PEP) is a day-ahead baseload index for Europe. Figure 44 shows that between 2007 and 2013 the baseload index in principle follows the crude oil price with a time lag of about one quarter of a year. Statistical analysis gives a correlation coefficient of \(r=0.47\) at 3-4 months’ delay, and thus a moderate correlation.

In the first three quarters of 2007 electricity prices remained rather constant while they doubled within three months at the end of that year. They increased further in the second half of 2008, reaching a peak in September 2008 some 230% above the March 2007 price. Subsequently, it decreased sharply back to 2007 levels in early 2009 following the oil price with a time lag of 3-4 months.

---

\(^80\) R&D activities to develop other forms of electricity storage have increased significantly over the past few years. This includes energy storage capacities from very small to very large and from short-term storage to seasonal storage.

\(^81\) Eurelectric is an association representing the interests of the European electrical power industry, including electricity generation and distribution companies from most European nations. So-called ‘Eurelectric Europe’ includes the EU-28 plus Iceland, Norway, Switzerland and Turkey.

\(^82\) No data available for storage capacity in Italy and Romania

\(^83\) Other influence factors include \(\text{CO}_2\) emission costs as well as typically minor costs for operation and maintenance.
From early 2009 to early 2011 the power index increased continuously by an overall 50%. After some fluctuation in 2011, it started low into 2012, but still above 2009 levels, and has increased steadily until early 2013 to come back to early 2011 levels.

**Figure 44: Electricity prices in Europe**

The power index shows a higher volatility than crude oil prices. Since the beginning of 2009, the crude oil price has continuously increased and in early 2013 has reached a price level equal to its price peak in 2008 some 180% above the lowest price in January 2009. In the same time frame, the price increase for baseload electricity is less pronounced at an overall 60%.

The correlation between electricity and natural gas prices is stronger than between oil and electricity. The correlation coefficient between the PEP and EU natural gas import prices (available until end 2012) is relatively high at \( r = 0.60 \) (2 months time lag). If only data until mid-2011 are used, the correlation is higher at \( r = 0.83 \). The correlation between the UK baseload electricity prices and the UK NBP gas spot prices (available until early 2013) is high at \( r = 0.75 \) (no time lag). If only data until mid-2011 are used, the latter correlation is slightly higher at \( r = 0.84 \). This shows that the correlation between electricity prices and natural gas prices has declined slightly since mid-2011. Besides, both gas spot and gas import prices have a higher correlation to electricity prices than oil prices. This is further discussed in the sections below.

Figure 45 shows that the US electricity spot prices also exhibited high values in 2008. Price volatility of different trading regions varies significantly while timing of major amplitudes is generally identical. In contrast to the crude oil price, US electricity prices have not increased since 2009.

**Source:** Study authors based on (EIA 2013a), (EC 2013a), (Eurostat 2013a)
2.5.3. Market fundamentals

Electricity generation

Figure 46 presents the gross electricity generation between 1995 and 2010 in the EU-27 by primary energy source.

Figure 46: Development of gross electricity generation by primary energy source in the EU-27 in TWh

Source: (EC 2012)
In 2010, some 3,346 TWh of gross\textsuperscript{84} electric energy were generated. More than one quarter of the electricity was based on nuclear power with a decreasing trend over the past years, solid fuels (coal) have decreased to 25\%, and natural gas has strongly increased to 24\% of generation. The share of crude oil and petroleum products in electricity generation has continuously decreased, reaching a level of only 3\% in 2010. Renewable power technologies continuously increased their share to 21\%.

Based on primary fossil energy consumption for electricity generation, the average gross efficiency of gas-fired power plants in the EU in 2010 was 50\%, while the average gross efficiency of solid fuel fired power plants was 36\%; oil-fired plants were between the two values\textsuperscript{85} (see below for a discussion of power plant efficiencies).

Electricity demand in the EU-27 continuously increased between 1995 and 2008 (see Figure 46). Caused by the economic downturn, it fell in 2009 and came back to almost 2007 levels in 2010 (see Figure 47). Since 2010, electricity demand has been decreasing and is currently at 2004 levels.

**Figure 47: Electricity demand in the EU-27 between 2003 and 2012 in GWh**

Electricity accounts for 21.1\% of final energy consumed in the EU\textsuperscript{86}. Thereof, 36.5\% is consumed in industry, followed by private households at 29.7\%, services at 29.4\%, transport at 2.4\%, and other users at 2.0\% (EC 2012).

\textsuperscript{84} Electricity consumption in the power plants needs to be deducted to give net generation available for transport and distribution to final consumers. Net generation was 3,180 TWh in 2010, resulting in an own consumption of power plants of some 5\% of gross generation (Eurostat 2013e).

\textsuperscript{85} Because of the small share of petroleum products in electricity generation, inaccuracies in the data for efficiency calculation do not allow for presenting a precise value here.

\textsuperscript{86} Status 2010; own calculation based on (EC 2012).
2.5.4. Price formation mechanisms

Functioning of wholesale electricity markets
In liberalised electricity markets, electricity is traded at power exchanges and bilaterally (Over The Counter – OTC; see Figure 48). Power exchanges have well-defined, standard power products, while OTC trade allows market participants to define contract details individually. OTC trade may be supported by trade platforms other than exchanges, or by brokers, but may also be concluded bilaterally between parties without intermediates. In general, power exchanges have a spot market for physical delivery of the traded electricity on the following day (“day ahead”) for individual hours of the day, while intraday trade allows making very short-term deals for same day or next day delivery of base load or peak load blocks. Intraday trade is far less relevant in terms of quantities than day-ahead trade (Monopolkommission 2011). Day-ahead prices are fixed in an auction for each hour of the following day. In contrast to that, intraday trade is continuous.

So-called “futures” are exchange-traded contracts for physical or financial delivery in future timeframes from weeks to years; also, options on futures are traded on exchanges (see e.g. (EEX 2012a)). So-called “forwards” are OTC-traded contracts for future physical or financial delivery. In contrast to futures, forwards are not standardised products, but are agreed individually between the contract partners. Some power exchanges in Europe, such as e.g. EEX in Germany or Nord Pool in Scandinavia, include OTC markets, offering the possibility to register the contracts and also offering contract clearing.

Figure 48: Structure of electricity wholesale markets

87 ECC is the clearing house of EEX. “ECC accedes to all transactions as the central contractual partner (central counterparty), and, hence assumes the counterparty risk.” (EEX 2012a).
It is generally assumed that exchange prices have a reference function for OTC trading because in the case of a price difference between an individual OTC contract and exchange prices, one of the two OTC contract parties could improve its position by trading at the exchange instead of concluding the OTC contract (Monopolkommission 2011). However, transparency of OTC trade is very low. The German Monopoly Commission (“Monopolkommission”) criticises that the large OTC trading volumes represent a major lack of transparency providing for significant possibilities and incentives for influencing exchange prices. The EU has reacted to such concerns by establishing the Regulation on Energy Market Integrity and Transparency (REMIT) and European Market Infrastructure Regulation (EMIR) in 2011 and 2012, respectively.

Exchanges use spot prices for calculating price indices. The EEX in Germany uses the day-ahead auction prices to calculate the Physical Electricity Index (Phelix); Phelix-Baseload is calculated as the average of all hourly prices of the day-ahead auction, while Phelix-Peakload is calculated from the hourly prices of the peaking hours 8:00 to 20:00 o’clock (Monopolkommission 2011).

**Figure 49: EEX spot traded electricity volumes compared to total consumption in Germany and Austria**

![Graph showing EEX spot traded electricity volumes compared to total consumption in Germany and Austria](image)

*Source: Study authors based on (AGEB 2012), (AGEB 2013), (EEX 2005-2012), (bmwfi 2013)*

In order to achieve a good reflection of the market in the spot prices, it is important to have a high liquidity of the market. The number of registered traders at the European Power Exchange (EPEX) spot market has increased from just below 140 in 2007 to 182 at the end of 2011 (Bundesnetzagentur 2012). Monthly traded volumes at power exchanges have increased significantly in Central Eastern Europe over the past years. Between January 2010 and June 2013, combined traded volumes in the Czech Republic, Hungary, 88 Regulation (EU) No 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale market integrity and transparency, OJ L 326/1 of 8.12.2011. The objective of REMIT is to increase the transparency and the stability of European energy markets, and to fight insider trading and market manipulations.


90 Spot trading is carried out by the EEX (Germany) and Powernext (France) subsidiary EPEX Spot.
Poland, Romania, Slovakia and Slovenia increased more than threefold; Poland increased by a factor of 3.3, while Hungary started from zero in early 2010, increased by a factor of 2.4 in 2011, a factor of 1.7 in 2012, and remained constant over the first half of 2013. The Nordpool only slightly increased traded volumes over the past three years (with typical seasonal variations), the UK and Ireland as well as Italy remained rather constant, while in Central Western Europe as well as Spain and Portugal traded volumes increased by around 25% (EC 2013a). Liquidity of electricity exchanges in terms of traded volumes as a percentage of national demand were 67% for Spain, 58% for Italy, 40% for Germany, 31% for Slovakia, 16% for Romania, 15% for the UK and 13% for France in 2011 (Renda et al. 2013).

Figure 49 shows that the traded spot market volumes at the German EEX for the German and Austrian market have increased significantly over the past years to reach 45% of combined consumption in 2012. Traded volumes of futures and in OTC trade are significantly higher than physically generated and consumed volumes, indicating that these contracts are not only used for hedging business transactions (Monopolkommission 2011). As an example, OTC trade on five brokerage platforms in Germany in 2009 with delivery in 2009 totalled 4007 TWh (Bundesnetzagentur 2010), compared to only around 550 TWh physical consumption in the same year.

**Market concentration**

Market liberalisation has been achieved to different degrees in the EU Member States so far. Market dominance of large generators in individual Member States hinders competition, and may lead to higher wholesale electricity prices than under perfect market conditions as described below. Figure 50 indicates the market share of the largest suppliers in each of the European Member States in 2010. Market dominance of single suppliers in some Member States is obvious.

**Figure 50: Market share of the largest generator in the electricity market in % of total generation in 2011**

![Map of Europe showing market share of the largest generator in the electricity market in 2011]  
**Source:** (Eurostat 2013g)  
**Note:** Grey – data not available
Interconnections

Physical capacities for the exchange of electricity between the Member States are still limited. Thus, market integration into a single electricity market in Europe has not yet been fully achieved, while regional price convergence is increasing and already very high, for example, in North-Western Europe. Efforts to build new interconnections have increased over the past years in order to accelerate market integration.

Price formation mechanism: The merit order curve

In order to set the price, power exchanges use the supply curve, called “merit order curve”, that reflects the marginal costs of the available generation technologies. The cost of generating electricity depends on which generating technology is used. Figure 51 shows an example of a merit order curve. Potential supply of electricity volumes from different types of power plants is depicted on the horizontal axis, while the vertical axis describes the marginal generation costs of each power plant (type). The merit order curve may differ for each hour of the year.

Marginal costs include

- fuel costs,
- CO₂ emission costs, as well as
- other minor operational and maintenance costs.

The cheapest power plant in terms of marginal costs, still necessary to cover demand during a given hour, sets the market price⁹¹. In this example, demand is 14 MW (see red vertical bar in Figure 51), crossing supply at a price of 15 €/MWh set by a nuclear power plant. All power plants to the left, i.e. all hydro power, wind power and solar power plants as well as some nuclear power plants will run during this specific hour and will sell the electricity for the price fixed at 15 €/MWh. Assuming an hour later that the demand is 20 MW and the merit order curve unchanged, the price will then be set by a coal-fired plant at 25 €/MWh. In the same way, at a potential demand of 25 MW, the price would be set by a gas-fired plant at 45 €/MWh.

The difference between the price fixed for the hour and the marginal costs for individual plants contributes to covering investment costs (depreciation) of the power plant, and to the profit margin of the operator.

Figure 52 shows the merit order curve of the German power system on 4 September 2012. Solar, hydro, and wind power are at the low end of the merit order curve with practically zero marginal costs. Next are nuclear power plants followed by lignite-fired plants and some biomass plants. Differences in efficiencies of e.g. individual lignite-fired plants lead to different marginal costs as shown in the figure. Another factor are variations in fuel costs paid by different operators. This explains why some lignite-fired plants have higher marginal costs than certain steam coal-fired plants.

---

⁹¹ Market participants may be situated abroad and cross-border capacities (or lack thereof) play a role in practical terms as they may limit market access for participants from abroad.
Figure 51: Merit order supply curve (example)

Source: Study authors based on (DIW 2013)

Figure 52: Exemplary illustration of a merit order curve for Germany in 2012; spot market prices of 4 September 2012

Source: Study authors based on (Kranner, Sharma 2013)
Next in the merit order curve are gas-fired power plants, then low sulphur fuel oil plants, and finally gasoil plants. At an average load of around 62 GW, steam coal plants are price setting at around 50 €/MWh in this case. At higher loads, gas plants set the price, or a few very inefficient coal plants. Only at very high loads of beyond 80 GW, oil plants become price setting. With the German peak load at below 80 GW, oil-fired plants should in principle never be price setting except when other plants have to be maintained or shut down for unplanned reasons. Consequently, oil is not relevant for electricity price formation and thus does not have a direct impact on electricity prices. In addition, solar and wind power may not be available, e.g. on a calm night. Under these circumstances, oil-fired plants may become price setting. In essence, due to their high marginal cost, it can be assumed that oil-fired plants are price setting whenever they are running.

For the sake of completeness, it should be noted here that demand curves are not perfectly vertical as indicated in Figure 51, but have a certain inclination because of price elasticity.

**Figure 53: Projected merit order curve for Germany in 2020**

*Source: Study authors based on (Kranner, Sharma 2013)*
Anticipating further growth of fluctuating renewable power plants, notably wind and solar power, in line with goals until 2020\(^2\), the German merit order curve will see additional capacity at zero marginal costs (see Figure 53).

By 2020, the average load may be fully covered by renewables, leading to an electricity market price of practically zero during significant times of the year. If demand is higher than generation by renewables as depicted in Figure 53, prices will be set by the remaining nuclear plants. A few years later, all nuclear plants will be retired, and renewable capacities further increased. Then, market prices of zero will become ever more frequent. In essence, solar and wind power with practically zero marginal costs put wholesale electricity prices under pressure by pushing power plants with higher marginal costs out of production. On the other hand, the low prices are not sustainable as they do not allow covering the initial investment, or, in other words, market prices are below the long-term marginal costs of renewable energies. Similarly, the low costs are problematic also for fossil power plants for the same reason.

Dark spreads and spark spreads are often used as indicators of the profitability of coal ("dark spread") and natural gas plants ("spark spread"). They are defined as the difference between the electricity price and the fuel price translated into costs per electricity produced with the help of the plant efficiency. The “clean” spreads additionally include the CO\(_2\) emission allowances costs. Thus, a clean spark spread of 5 €/MWh signifies that the electricity price is €5 higher per MWh than the combination of fuel costs and CO\(_2\) costs for producing this MWh. For the calculation of the spreads, standardised values for plant efficiencies are used.

From a different perspective, clean dark spreads higher than clean spark spreads indicate that gas-fired power plants are price setting in the merit order curve rather than coal-fired plants, while inverse spreads indicate an inverted merit order curve with coal-fired plants setting the price.

Figure 54 shows the clean dark and spark spreads for Germany and the UK since 2007. They clearly indicate that typical gas-fired power plants in Germany are not recovering their marginal costs at present, and only very efficient plants can run profitably, while in the UK positive contribution margins are achieved. For coal, contribution margins are positive in both countries, however, in the UK they are higher.

This indicates that natural gas-fired power plants are price setting more often than coal-fired plants. Renewable energies (excluding biomass-based) and nuclear power plants are never price-setting in an electricity mix including all electricity generation technologies in relevant shares. The impact of oil price on electricity prices is thus mainly through gas, which itself is impacted by the oil price through oil-indexed long-term contracts. The impact of coal prices on electricity prices is less pronounced, and the limited impact of oil price on coal prices further weakens the oil price impact on electricity through this route.

In other electricity mixes, price setting characteristics may be different and lead to different impacts of oil price on electricity prices.

---

\(^2\) The so-called "20-20-20" targets of the EU set three key objectives for 2020: a 20% reduction in EU greenhouse gas emissions from 1990 levels; raising the share of EU energy consumption produced from renewable resources to 20%; a 20% improvement in the EU energy efficiency. The goals are broken down into individual goals for all Member States.
Impact of the Oil Price on EU Energy Prices

According to (Enggrav, Noreng 2012), Germany on average has a less efficient gas-fired power plant portfolio than the UK or the Netherlands. This is due to the average age of German gas-fired power plants of 19 years, while for the UK and the Netherlands this is 13 and 16 years, respectively. Furthermore, the average size of German gas plants is relatively small (259 MW) compared to the UK (607 MW) and the Netherlands (584 MW). This makes it even harder for German gas plants to make profits, in addition to lower clean spark spreads.

Figure 55: Average gas-fired power plant efficiencies in Germany, the Netherlands and the UK

Notes: “Claus C” is a recently built highly efficient 1940 MW natural gas-fired plant in the Netherlands; “Emden 4” is an old, inefficient gas-fired power plant in Germany.

Calculating the impact of the costs of CO₂ emissions on electricity generation costs, depending on the EUA prices and depending on the plant efficiencies, shows that EUA...
prices of 15-30 €/t$\text{CO}_2$ have a significant effect on profitability for low efficiency plants (Enggrav, Noreng 2012). At 50% power plant efficiency, an EUA price of 20 €/t$\text{CO}_2$ translates into CO$_2$-related electricity costs of 8 €/MWh for gas plants. At 30% plant efficiency this gives 13.33 €/MWh, while at 60% efficiency it results in only 6.67 €/MWh. At low spark spreads a high efficiency thus makes the difference between positive and negative margins.

For coal fired plants, an EUA price of 20 €/t$\text{CO}_2$ results in CO$_2$-related electricity costs of 23.07 and 17.30 €/MWh at 30% and 40% efficiency, respectively. Thus, at higher than current EUA prices high efficiency gas plants and low efficiency coal plants reverse their position in the merit order because of the CO$_2$ costs. So EUA prices can quantitatively and qualitatively change the merit order curve in case they are high enough, and are thus a major factor in electricity prices. The current very low EUA prices, however, have practically no influence on the merit order curves.

Regional market integration

The Nordic market has the longest history in electricity market integration. Denmark, Finland, Norway, and Sweden, and more recently Estonia, Latvia, and Lithuania are included in the Nord Pool power exchange.

Denmark (high wind share), Finland (high nuclear share), Norway (very high hydro power share), and Sweden (high hydro power and nuclear shares) have large capacities with low marginal costs.

Physical interconnections between and within the countries are sometimes not sufficient to allow for maximum power exchange. Under such circumstances, market splitting is exercised with two regions in Denmark, one in Finland, five in Norway$^{93}$, four in Sweden, and one in each of the Baltic States. In general, price differences are small between the Scandinavian countries and Estonia. Latvia and Lithuania are still rather decoupled from the Scandinavian countries, but coupled to each other.

The combined merit order curve of the Nord Pool in 2009 (i.e. without the Baltic states) is shown in Figure 56, displaying large wind and hydro power as well as nuclear capacities. At low demand and high hydro reserves, nuclear is price setting. With market splitting, Norwegian prices may go down to practically zero based on 100% hydro power at certain times.

Regional market integration is not perfect in all parts of Europe. A recent European Commission report on European electricity markets (EC 2013a) described the current status as follows: “The ratio of adverse power flows (or flows against price differentials – FAPDs) is a useful measure of the effectiveness of existing market couplings or integration of neighbouring power markets. [...] In the Central West European region the ratio of power flows against price differentials remained insignificant in the first quarter of 2013, though prices in certain regional markets showed clear signs of divergence from others. Another good example for market couplings can be found in Central Eastern Europe, notably between the Slovakian and Hungarian markets, where adverse flow ratios fell below 1% in Q1 2013 from 40% measured in Q2 2012.” On the other hand, adverse flows have remained at around 30% for the past years between Hungary and Austria. Adverse flows between France and Germany are zero since the beginning of 2011, while they have remained at around 15% between Germany and the Netherlands, and at around 40% between Germany and the Czech Republic (EC 2013a).

---

93 This number can vary.
The Visegrád group of countries is a good example of the impact of interconnectors on pricing. In September 2012, Hungary acceded to the Czech-Slovakian market coupling area, significantly decreasing price premiums of the Hungarian market over the German electricity market. The weekly percentage ratio of price convergent hours between the Hungarian and the Slovak markets jumped from around 10% to an average of 80% in September 2012 (EC 2013a).

**Capacity mechanisms**

The price mechanism explained above defines an energy-only market, i.e. a market where only the electricity produced is financially rewarded. However, so-called capacity mechanisms are implemented in a few Member States (e.g. Greece, Ireland, Lithuania, Portugal, Spain), or are in the process of being implemented legally in some other Member States (e.g. Belgium, France, Italy, Poland, UK); in Finland and Sweden, a capacity reserve is implemented (see Figure 57).

Capacity mechanisms financially reward the availability of plant capacities no matter whether the plant is running or not, aiming to ensure that enough generation capacity is available and plants perceived to be relevant for the energy system are not decommissioned, because they are not making a profit by selling energy (see German example on page 93). Other options to support a better balancing of supply and demand include demand side management and storage capacities. Capacity payments for power plants thus increase overall system costs without being related to input fuel costs. As they do not directly affect wholesale electricity prices through the merit order curve, these increased system costs need to be recovered through other routes, e.g. grid charges or other general levies. Capacity mechanisms are relevant to take into account here as, where established, they reduce the impact of the oil price on electricity prices since they constitute an additional price component independent of fuel costs.
However, there are different options of from whom and how to recover these costs. Depending on the option chosen in each case, capacity mechanisms may be relevant for wholesale markets, or for retail markets.

Other capacity addressing mechanisms, notably demand response or demand-side management, influence the demand curve and thus directly lead to changes in wholesale prices.

**Figure 57: Capacity mechanisms in Europe**

![Capacity mechanisms in Europe](image)

*Source:* (Graichen 2013)

### 2.5.5. Regional differences in the EU

EU Member States have a wide variety of electricity generation mixes as shown in Figure 58. Poland has a large share of coal-fired plants, while France has a large share of nuclear power. Italy, the UK, and Lithuania have large shares of gas plants, while Spain has a significant share of renewables. Lithuania\(^{94}\), Italy, and Spain have the largest shares of oil and petroleum products in the power mix, with 11%, 7% and 6%, respectively. These different electricity mixes lead to different merit order curves and thus to different price setting structures.

\(^{94}\) Lithuania had a high nuclear share until the end of 2009.
In Poland, coal should set the price much more often per year than natural gas. In Italy, and Lithuania, natural gas and, to a lesser extent, oil should be price setting most of the time; Spain will have even less oil dominance. The UK electricity prices will be dominated by natural gas. In France, nuclear power will be price setting during large parts of the year, while during cold weather\textsuperscript{95} coal and natural gas will set the price.

**Figure 58:** Electricity generation of 10 selected EU Member States by primary energy source in 2010

![Electricity generation chart](image)

**Source:** Study authors based on (EC 2013a), (EC 2012)

Major regional differences in baseload price volatility exist. A similar price peak as for crude oil is visible in 2008 for baseload electricity prices; however, the magnitude of the price increase in 2008 significantly differs between regions.

Figure 59 shows very high electricity prices for Italy compared to other EU Member States, reflecting the dominance of natural gas and oil on exchange prices. Relatively low Lithuanian electricity prices, in spite of an electricity mix similar to Italy and based on higher than EU average gas prices in both countries, seem contradictory. However, most of the electricity consumed in Lithuania is imported from Russia, which is not reflected in the electricity mix. Thus, the relatively low electricity prices result from cheap imported electricity, and not from the national electricity mix. The UK shows strongly increasing electricity prices since end of 2012, caused by strongly increasing gas prices at the NBP.

\textsuperscript{95} France heavily relies on electric residential heating, resulting in an additional power demand of 2300 MW for every degree Celsius of temperature decrease during the heating period; see e.g. S. Domergue, Requirements for the implementation of a capacity mechanism in France, dena Conference on Capacity Mechanisms, Berlin 30 August 2012
Figure 59: Baseload electricity prices in European countries

Source: Study authors based on (EIA 2013a), (IEA 2013), (EC 2013a), (Nordpool 2013), (Gietda Energii 2013), (Eurostat 2013a), (HUPX 2013), (Baltpool 2013)

Note: PEP – Pan European Power Index

Figure 60: Price difference between baseload electricity and PEP index for selected European countries

Source: Study authors based on (EIA 2013a), (IEA 2013), (EC 2013a), (Nordpool 2013), (Gietda Energii 2013), (Eurostat 2013a), (HUPX 2013), (Baltpool 2013)

Note: PEP – Pan European Power Index
Nord Pool prices including Finland depend on hydro power availability, and thus show unique patterns compared to other Member States. The low prices in July 2012 can be explained by higher than long-term average hydro reserves in Norway (EC 2013a). High prices in France in February 2012 can be explained by the exceptionally cold weather, which caused demand for heating purposes to be very high. Low electricity prices in Spain in the first quarter of 2010 are a consequence of exceptionally high hydro reserves and average wind performance, while economic recession still caused industrial electricity demand to be low (EC 2013a).

2.5.6. Impact of oil price on electricity prices

Summing up, the most important factors influencing electricity prices are:

- Electricity generation mix, including share of renewable energies: different technologies and different fuels impact the marginal electricity generation costs, which through the merit order curve are the basis for the price setting mechanism;
- Supply/demand balance: the price is set where the supply/demand curve intersects the merit order curve of electricity generation;
- Prices of fossil fuels for power generation: fuel prices notably for coal and gas, but also for oil where it has a relevant share in the national electricity mix impact the merit order curve;
- Interconnection capacities with other Member States: interconnections enable import of electricity from lower cost sources; influence on national prices will depend on interconnection capacity and on generation capability in neighbouring countries;
- Price of CO$_2$ emission allowances (EUAs).

Direct impacts

How important is the oil price as a determinant of electricity prices? As shown above, between 2007 and 2013 the Pan European Power Index (PEP) seems to follow the crude oil price with a time lag of about a quarter year. However, the correlation is only moderate. Oil price changes have a direct impact on electricity prices where oil itself is used as a feedstock for power generation. Only about 3% of all EU electricity is produced from oil products, strongly limiting the extent of this type of impact. Only a few Member States (notably Malta and Cyprus) are particularly vulnerable to oil price changes in this regard.

Indirect impacts

The most important indirect impact is the oil price’s impact on natural gas through oil indexed contracts (see section 2.3). The relatively small impact of oil prices on coal stemming from coal extraction and inland transport (see section 2.4) provides for only a small indirect impact on electricity prices.

Since about 25% of all EU electricity is generated in gas-fired turbines, electricity prices are closely tied to gas prices (see section 2.5.2 above). Moreover, gas-fired power plants are more often price setting than coal-fired power plants making gas more relevant for electricity prices. Electricity prices therefore tend to also follow oil prices since, as discussed above, gas and oil prices are linked through various mechanisms including most notably oil indexation. Power utilities are in this sense no different from gas utilities; they buy gas from wholesalers through a mix of oil-indexed and spot-market prices (with the actual mix varying from country to country). However, there is one key difference between power and gas utilities: the former generally have access to a wider range of alternative energy sources.
While gas retailers only have a very limited range of alternatives to natural gas (mainly biogas), power utilities generally have the option of using other fossil resources (coal or oil) or non-fossil power sources (nuclear, renewables). In theory, they can therefore react to rising gas prices by increasing their use of non-gas power generation assets; although in practice the scope for such arbitrage is limited due to various barriers. For example, coal is not an ideal substitute to gas when lowering CO\textsubscript{2} emissions is a major policy imperative. Renewables cannot replace all natural gas power generation due to their higher degree of intermittency (as well as generally higher cost). Nuclear power plants are expensive and difficult to build in today’s political context. This leaves oil, which is of course tied to oil prices (as well as being more CO\textsubscript{2} intensive than natural gas). The negotiating power of natural gas buying power utilities is therefore limited, although the ability to switch from gas to coal (due to the currently weak constraints on CO\textsubscript{2} emissions) presently allows them to exert some pressure on their gas suppliers.

What is more, power generators have more to lose from sudden gas price movements than gas distributors, since the “take-or-pay” clauses that usually accompany oil-indexed contracts can lead to severe losses if electricity prices fall below a given threshold (the purchaser will be forced to buy gas at times when power prices will not cover fuel prices). Since electricity prices are determined by a range of factors, including the price of coal. As electricity is not easily storable, it is possible that electricity prices fall while gas prices increase. If competing power retailers are able to secure cheaper electricity (e.g. from nuclear sources), they will put pressure on the gas dependent utility to lower its prices and thus incur losses.

Another point that can be made is as follows. Since oil indexation tends to lead to higher gas prices, it may have the effect of discouraging power generators from investing into gas-fired power assets. Switching from coal or oil to gas always involves substantial costs; if the price advantage of gas is lessened, so will be the incentive to switch. All other things being equal, this could result in higher electricity costs and/or CO\textsubscript{2} emissions. In the USA, where gas prices have fallen dramatically, many power generators switched to gas and thus initiated a movement that led to low electricity prices and CO\textsubscript{2} emissions.

Also, the rigidity of oil indexed prices can be a strong disincentive to invest into gas power plants if retail prices are deregulated, since utilities are forced to commit to minimum purchase volumes (as per the so-called take-or-pay contractual terms). If gas prices increase faster than electricity prices, utilities will be penalised. According to (Melling 2010), the higher share of oil-indexed gas supplies in Eastern Europe may help explain why this region invests less in combined-cycle gas turbine power plants than the UK and other North Western European countries. Melling goes on to argue that given the increased importance of the power sector in gas markets, its greater need for flexible price mechanisms may be the main driver of de-indexation, i.e. the transition toward spot pricing.

In summary, the cost of generating electricity in Europe is linked to oil mainly through the impact of the latter on gas prices though indexation contracts. As there are other electricity generation technologies including nuclear and renewable power plants and different national electricity mixes, the impact of the oil price on electricity prices through natural gas (strong link based on oil-indexed contracts) and through coal (weak link through fuel costs in extraction and inland transport) overall is limited. The moderate correlation found between oil price and electricity prices, and the rather large variations in national electricity prices are a consequence of this.
2.6. Oil products

2.6.1. Introduction

Oil products are used for a variety of purposes such as transport (e.g. LPG, gasoline, kerosene, diesel, heavy fuel oil/marine bunker fuel, etc.), heating and cooking (e.g. kerosene, gasoil, etc.), and power production (e.g. gas oil, fuel oil, etc.) as well as in industrial processes. In the EU, motor-fuel represents the biggest use of refined oil products.

All oil products are co-products and are made by distillation and further processing of crude oil in refineries. The configuration of the refinery defines the produced quantities of each product and can only be varied slightly. The produced product mix can also be slightly influenced by the used crude feedstock. Using lighter i.e. lower density crude results in higher quantities of light products such as gasoline and diesel while the use of heavy crude produces higher quantities of heavy products (e.g. fuel oil). Therefore, the possibility for refineries to react to demand shifts in local product markets is limited (Pieterse et al. 2008), (EC 2010a). However, investments in additional technology influence product output.

2.6.2. Price trends

Crude oil and oil product spot prices basically run parallel in northwest (NW) Europe (Figure 61). Crack spreads\textsuperscript{96} for gasoil and kerosene have mostly been between about 10 and 20 €/bbl.

Figure 61: Oil product spot prices in northwest Europe

![Graph of oil product spot prices in northwest Europe]

\textbf{Source:} Study authors based on (IEA 2013), (EIA 2013a), (Eurostat 2013a)

The crack spread for gasoline has shown some variability in recent years. Figure 61 shows a peak of about 17 €/bbl in 2007 and a virtually non-existent spread for certain periods in 2008 and 2011. Between 2008 and 2012, the spot price level of marine bunker fuel\textsuperscript{97} increased more strongly than crude oil spot prices did. Correlation coefficients for all oil

\textsuperscript{96} Crack spread: differential between the price of crude oil and oil products extracted from it.

\textsuperscript{97} Marine bunker fuels are fuels used for ship propulsion. Several different qualities exist. For this study a bunker fuel with 180 cst (centistokes describes the viscosity of the fuel) at Rotterdam harbour has been used. Prices are for fuels delivered on board including barge transport and/or ex-price fees.
products in Europe and the USA show very high values of $r>0.95$ without time lags, indicating very strong correlations.

As Figure 62 shows, spot prices for oil products in the USA develop similarly to the European spot prices\textsuperscript{98}.

**Figure 62: Oil product spot prices in the USA**

![Chart showing oil product spot prices in the USA](chart)

Source: Study authors based on (IEA 2013), (EIA 2013a), (Eurostat 2013a)

### 2.6.3. Market fundamentals

Between 2000 and 2008, North Sea crude production declined by about 2 million barrels per day to a level of 4.3 million barrels per day. The result was an increased share of imported crudes (up by 5% to 80% in 2008). The quality and composition of the crudes determines the level of processing and pre-processing required to achieve the desired output of oil products. In this case, replacing North Sea crudes with heavier imported crudes like Urals crude and Arabian Gulf crude results in a higher share of less valuable heavy oil products from distillation and requires additional processing to produce higher value oil products. In addition, the sulphur content of imported crudes is higher than in North Sea crude, making it less attractive for the production of low sulphur fuels as required in the EU. Heavy crudes with high sulphur content also have increased impurities of nitrogen and metal, making it more costly to produce light products (EC 2010\textsuperscript{b}).

Over the last years, European policy has stimulated the consumption of diesel fuel for transport, resulting in a shift of local oil product demand from gasoline to diesel. Between 1990 and 2010, demand for middle distillates (predominantly diesel for transport but also kerosene) almost doubled. This resulted in a growing asymmetry between product output from European refineries and European product demand. Since refineries can only slightly adapt to changes in the demanded product mix, the increased supply of diesel fuel for transport, to some extent, also leads to increased gasoline production. Those local imbalances between product supply and demand are equilibrated by international trade (see Figure 64).

\textsuperscript{98} Using IEA “Energy prices and taxes” as source for US gasoline prices, a disproportionate price increase can be detected in 2011. Data provided by EIA do not support this price increase, which is probably due to a switch in data provider by IEA.
In the USA, gasoline is by far the most important product. For some time, US refineries were not able or have not chosen to adapt to the strong gasoline demand which has developed over the last two decades. Therefore, the US imported surplus gasoline from European refineries to compensate for its own deficits and in return exported diesel to Europe. Only recently have the US refineries switched to increased gasoline output, and European gasoline exports previously destined for the USA have been directed towards Africa.

The increased demand of diesel fuel in Europe is met by additional imports from the Former Soviet Union (FSU) and the Middle East (Pieterse et al. 2008), (Meijknecht et al. 2012).

The EU oil product market is considered to have passed its peak demand between 1990 and the financial crisis in 2008. Between 2005 and 2008 the demand fell by 3% (EC 2010b).

Since 2000, the net EU motor gasoline export has increased from about 15 Mt/a to about 40 Mt/a. In the same period, diesel, and kerosene imports increased to 20 Mt/a and 15 Mt/a, respectively (see Figure 64).
Figure 65: Oil product output from European refineries in 2011

Source: Study authors based on (Eurostat 2013d)

Figure 66: Development of refinery capacity and utilization rates in the USA, Europe and the rest of the world

Source: Study authors based on (BP 2013)

Increasing exports and imports are a result of the inability of the refinery industry to adapt to regional shifts in demand, (Pieterse et al. 2008).

The EU is the second largest producer of oil products in the world. Refineries exist in 22 Member States with a total product output of 888 Mt in 2011 (EC 2010a), (Eurostat 2013d). Figure 63 and Figure 65 show details of the European refinery capacity and product mix over time and its regional distribution, respectively. There is a current over-hang in European refining. The resulting trend towards reduction in refining capacity since 2008 visible in Figure 66 is expected to continue in the coming years, further aggravated by increasing competitive pressure from refineries on the US East Coast (IEA 2013b), (DG Energy 2013a).
2.6.4. Price formation mechanisms

Oil products are internationally traded commodities. The international trade ensures that the price difference between different regional markets is kept at a minimum. Therefore, product (as well as crude) prices are determined by demand and supply on a worldwide basis. Trade also ensures outbalancing deviations between regional oil product supply and demand. The cost of production for oil products predominantly depends on the crude oil prices. The ACCC (Australian Competition and Consumer Commission) states that crude oil accounts for 85%-90% of the cost of refined products. However, the international demand for oil products can also influence the crude oil price (AIP 2013).

Furthermore, refining margins and product transportation costs have an influence on oil product prices. Refining margins are the differential between the price of crude oil and oil products extracted from it. They are influenced by the price and quality of the feedstock (i.e. crude oil), by regional and global product demand, and by the availability and utilization rate of regional and international refineries. In addition, the complexity of the refinery has an influence on its achievable margin. E.g. more complex cracking refineries can produce a larger share of more valuable middle distillates and can therefore achieve a higher margin than e.g. simpler hydroskimming refineries (EC 2010b), (Pieterse et al. 2008), (Grant et al. 2006).

**Figure 67: Refining margins for simple and complex refineries and various types of crude oil**

![Refining margins chart](source: Study authors based on (IEA 2013b))

After the “golden years” of profit margins in the refining sector from 2004 to 2008, margins declined to a minimum for European refineries due to a falling European demand for oil products, existing overcapacity in Europe, and higher crude feedstock prices (Meijknecht et al. 2012).

2.6.5. Regional differences in the EU

Regional prices vary by transport costs from major price setting trading points such as Rotterdam, which is price setting for NW Europe. This is true both for price differentials between Member States and within individual Member States.
For example, within Germany regionally differentiated prices for eight regions are fixed by service providers on a daily basis. Regional production and demand balances also play a role. However, in general, regional differences are very small.

2.6.6. Impact of oil price on oil products prices

As mentioned above, the crude oil price is the predominant driver for oil product prices. Product prices therefore directly and immediately reflect the price development of crude oil (see Figure 68), in qualitative and quantitative terms. Other factors only lead to small variations of oil product prices.

Figure 68: Correlation between crude oil price and selected oil products

Source: Study authors based on (EIA 2013a), (IEA 2013), (Eurostat 2013a)
2.7. Conclusions

The crude oil price is the predominant driver for oil product prices, which directly and immediately follow oil price changes. For other energy commodities; the strongest impact of the oil price on wholesale energy prices is through oil-indexed long-term gas contracts. The share of oil-indexed contracts, which shows significant regional variations in Europe, and the details of the contractual agreements determine the strength of the impact. There is a general, but slow trend away from oil-indexation in gas contracts. For coal, the impact of the oil price is weaker. It is largely based on the high consumption of oil products in coal extraction and inland transport. International sea freight rates develop independently from the oil price in spite of the fact that fuel costs are a major element of freight costs.

Electricity prices in general show a moderate correlation to oil price developments. Through the merit order curve, national electricity mixes lead to different prices and sensitivities. Market integration into a single electricity market in Europe has not yet been fully achieved. Since oil only has a very minor role as a fuel in electricity generation, the prices of oil and of oil products have little direct impact on electricity prices in Europe. The most important indirect impact is through oil-indexed natural gas contracts, reinforced by the fact that gas-fired power plants are often price setting in the merit order curve. The smaller impact of oil prices on coal provides for a small indirect impact on electricity prices. Figure 69 shows routes of direct and indirect impacts of the oil price on energy commodity prices. The thickness of the arrows qualitatively corresponds to the strength of the impact: thick lines indicate strong impacts, thin lines weak impacts of oil price on wholesale energy prices. This graphical representation is not comprehensive; however, the most important impact routes identified in this chapter are included.

**Figure 69:** Overview on most important price formation mechanisms of energy commodities

Although both gas and oil share fundamental price drivers (such as economic development) and their prices often seem to be correlated, in places where oil indexation is basically absent, such as the USA, gas and oil prices are often decoupled, proving that there are no fundamental reasons why gas prices should follow those of oil.
3. RETAIL PRICE TRENDS AND PRICING MECHANISMS

**KEY FINDINGS**

- Despite market integration, the EU retail energy market is characterised by large disparities and differences in the price setting mechanisms and market models that are applied. Moreover, large discrepancies at the level of prices persist across countries.

- In the majority of Member States, certain end-user categories (particularly households) are still being offered fixed regulated tariffs with levels determined by the national regulator. Where regulated tariffs compete with the “free-market”, competition is hindered and prices are kept artificially low.

- Energy retail prices have four major price components, namely wholesale energy costs, supplier margins, network charges, as well as taxes and other charges. The relative share of these components varies significantly depending on the type of consumer (private, industry, etc.). Of these components, network charges, taxes, and other charges are regulated by each Member State, and may vary geographically within individual Member States. However, they are independent of the supplier, are in general passed on fully to the final consumer, and are independent of any impact of the oil price. Consequently, in terms of translation of the oil price, these two price components have a dampening effect.

- On average, the non-regulated price components, most importantly the wholesale energy costs have a share of 40%-60% of the final electricity or gas price of private or industrial consumers, while regulated components independent of oil price impacts represent a share of 60%-40%. Consequently, any impact of the oil price on wholesale prices only affects 40-60% of the final consumer price (except for VAT). Network tariffs governed by the national regulatory authority and taxation are becoming increasingly important element in the final price.

- The market structure and degree of market liberalisation are also an important factor in explaining discrepancies in retail electricity prices across the EU.

- Oil prices have a greater impact on retail gas prices than on electricity prices. While the main components of retail energy prices are the same for both, oil-indexation plays a stronger role in influencing retail gas prices than for electricity.

The objective of this chapter is to analyse European electricity and gas retail markets. After discussing the European retail energy market for electricity and gas, the main components of retail energy prices are analysed. Additionally, regional differences in market structures are presented. Finally, the resulting role of the oil price as a factor influencing energy bills for household and industry consumers is summarized.

3.1. The European retail energy market

3.1.1. Introduction

This section presents a general overview of the main characteristics of the EU energy retail market for electricity and gas, including the current level and recent evolution of retail prices. The retail energy market is the market through which end users, such as industry and household customers, purchase energy directly for their own consumption.
Energy services ranging from production, trading, transmission, distribution, and retail are charged to end-users in the form of an energy bill. The total amount of this energy bill, including all taxes and charges, constitutes the retail price. The analysis will focus on electricity and gas bills since they account for the largest share of energy bills for different consumer categories. Also, electricity and gas retail markets have recently gone through important changes that are interesting to explore in light of the effort made at the EU level to create liberalized electricity and gas markets.

Retail energy prices have been drawn from Eurostat, complemented by national data sources such as energy regulators, statistical offices, and trade associations. For ten selected Member States a thorough research was carried out on the websites of energy regulators and national statistical offices to retrieve data providing detailed decomposition of energy prices. Annual reports produced by the national regulators were also analysed, if an English translation was available. When information was not readily available, direct contact was established with representatives of these bodies. Unfortunately, most Member States have adopted a national approach for the classification of consumption bands and consumer categories, which is often incompatible with Eurostat, or not defined in sufficient detail.

However, in some cases, the consumption band can be quite detailed on the basis of the consumption patterns of consumers (e.g. Finland) or approximate estimates on average consumption (e.g. Italy, Germany, Hungary). As a result, in spite of this extensive effort, a comprehensive but not fully harmonised data set could be compiled, and for some Member States best available data were sourced from Eurostat (for Bulgaria, Lithuania, Poland, and Spain).

Eurostat defines a large number of consumer categories. This analysis will focus on the two most important ones: households and industry, since these two categories alone make up for more than 50% of final energy consumption in the EU.

Additionally, Eurostat data categorise consumers by predefined annual consumption bands. There are in total five household categories for electricity and three for gas. On the other hand there are seven industry categories for electricity and six for gas. The most complete series provide prices inclusive/exclusive of taxes and Value Added Tax (VAT) for both gas and electricity. For some countries it is also possible to retrieve separate data for taxes and network tariffs.

For simplicity, an initial high level analysis of price trends using Eurostat statistics is carried out in order to give a first impression of energy bills across the whole EU. Medium size consumers for both domestic and industry end-users have been selected for these purposes:

99 Ten EU Member States were selected to showcase various regional energy sub-markets within the EU and to describe different energy market situations across the EU. A set of five criteria was chosen in order to achieve a balanced and representative selection. For more details, please refer to Annex D. For the following 10 Member States more detailed analyses of wholesale markets and of the structure of retail energy bills were made: Bulgaria, Finland, France, Germany, Hungary, Italy, Lithuania, Poland, Spain, and the UK.

100 Energy end user categories: private households, agriculture, industry, road transport, air transport (aviation), other transport (rail, inland navigation), services, other.
Electricity:
- Band DC: 2,500 kWh < Consumption < 5,000 kWh for households
- Band IC: 500 MWh < Consumption < 2,000 MWh for industry.

Gas:
- Band D2: 20 GJ < Consumption < 200 GJ for households
- Band I3: 10,000 GJ < Consumption < 100,000 GJ for industry.

These same categories are used by the European Commission for its benchmarking reports\(^{101}\) and can be treated as representative of the general trend. It also has to be noted that for large industrial consumers time series are often incomplete.

### 3.1.2. Market fundamentals

Energy bills for both households and industry consumers have increased in the past years and can account for up to 17% of household total expenditure across the EU. For poorer households they may reach up to 22% of the total household budget (EC 2013f). Energy bill increases, particularly following the cold winter of 2012, have led to political turmoil and heated debates in some countries (e.g. in Bulgaria and Lithuania).

Electricity and natural gas are the dominant sources of energy for households and industry consumers. In the year 2012, gas accounted for 39% of total energy consumption of households and 30% for industry. Electricity accounts for 25% and 30% of energy consumption for households and industry, respectively (Enerdata 2012). It should be noted that while the share of electricity for both consumer categories have continuously increased since the 1990s, the contribution of oil products, coal, and wood have decreased during the same period with only a few exceptions across Member States.

### Market structure

Traditionally, gas and electricity retail markets in Europe were operated as national monopolies, with large state-owned utilities in charge of managing the infrastructure and supplying energy to end-users. With the aim to create the Internal Energy Market, the European Union has pushed forward the liberalisation of national energy markets, both at the wholesale and retail levels. Member States were formally required to liberalise their retail electricity and gas markets by 1st July 2007, but many discrepancies still exist at the EU level. In principle, a competitive retail market is expected to benefit end-users as the competitive pressure should induce companies to lower prices and improve services delivered.

The European retail energy market is characterised by large disparities and differences in the price setting mechanisms and market models that are applied. Annex E analyses the existing regulatory framework and provides the detailed gas and electricity price decomposition for 10 selected Member States. This analysis is the basis for highlighting specific characteristics and identifying the key impacts of the oil price on retail prices.

---

Overall, the following key market players are shaping retail energy markets:

- **Energy suppliers and retailers:** purchasing energy from the wholesale market, they are responsible for selling it directly to households and industrial consumers.

- **Transmission and distribution system operators:** in charge of transporting the energy commodity and managing the high voltage energy infrastructures. Transmission Systems Operators (TSOs) are responsible for the correct functioning of the wholesale market. Distribution System Operators (DSOs) are responsible for providing connection to the low voltage network and delivery access points to retailers and consumers.

- **Large industrial consumers:** businesses for which energy represents an important variable cost. Depending on their business and location they may be directly connected to the transmission network. Given the large quantities of energy purchased, they have the possibility to negotiate their contracts directly with wholesale traders.

- **Households and small/medium size business consumers:** depending on the Member State, they have some scope to choose between competing energy retailers and price plans.

In most cases, the energy supplier is the key contact point for end-users, who receive one single energy bill including all charges from them. Rarely consumers may receive two bills, one from the supplier and one from the DSO. In certain cases consumers may receive an integrated energy bill for both gas and electricity; however, usually energy bills are separated for both gas and electricity.

**Regulated tariffs persist in Europe despite the liberalisation of electricity and gas markets**

As noted above, retail electricity and gas markets had to be fully liberalised in 2007. However, in reality in most EU Member States regulated tariffs persist alongside market-based price formation mechanisms. Table 5 below shows the 18 countries still offering regulated tariffs to domestic end-consumers, also indicating the percentage of customers being offered regulated tariffs, where available (ACER, 2012). The number of countries providing regulated electricity tariffs to the industry sector is somewhat smaller (12 Member States). Regulated tariffs are in place to protect end-users from high prices and volatility but, if not set at the right level, might hinder competition and the development of a competitive retail market by impeding the entry of new suppliers in the market. Regulated tariffs also weaken the link between wholesale prices and retail prices, or at least tend to partially delay it. While this could positively impact retail prices when wholesale prices are high, it also implies that end-users cannot fully benefit from a decrease in wholesale prices. However, in the same fashion, regulated retail prices will also dampen any impact of the oil price on retail prices, since price changes at the wholesale level cannot directly translate into price increases or decreases at the retail level.
Table 5: EU Member States regulated tariffs for domestic electricity and gas consumers

<table>
<thead>
<tr>
<th>Country</th>
<th>Electricity Household regulated prices</th>
<th>Gas Household regulated prices</th>
<th>% of household customers under regulated prices (electricity)</th>
<th>% of household customers under regulated prices (gas)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Austria</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Belgium</td>
<td>Yes</td>
<td>Yes</td>
<td>7.7</td>
<td>8.1</td>
</tr>
<tr>
<td>Bulgaria</td>
<td>Yes</td>
<td>Yes</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Cyprus</td>
<td>Yes</td>
<td>No</td>
<td>100</td>
<td>NA</td>
</tr>
<tr>
<td>Czech Republic</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Denmark</td>
<td>Yes</td>
<td>Yes</td>
<td>85</td>
<td>NA</td>
</tr>
<tr>
<td>Estonia</td>
<td>Yes</td>
<td>No</td>
<td>100</td>
<td>NA</td>
</tr>
<tr>
<td>Finland</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>France</td>
<td>Yes</td>
<td>Yes</td>
<td>94</td>
<td>86.3</td>
</tr>
<tr>
<td>Germany</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Greece</td>
<td>Yes</td>
<td>Yes</td>
<td>98</td>
<td>100</td>
</tr>
<tr>
<td>Hungary</td>
<td>Yes</td>
<td>Yes</td>
<td>99</td>
<td>100</td>
</tr>
<tr>
<td>Ireland</td>
<td>Yes (until April 2011)</td>
<td>Yes</td>
<td>63</td>
<td>72.9</td>
</tr>
<tr>
<td>Italy</td>
<td>Yes</td>
<td>Yes</td>
<td>83</td>
<td>89.6</td>
</tr>
<tr>
<td>Latvia</td>
<td>No</td>
<td>Yes</td>
<td>NA</td>
<td>100</td>
</tr>
<tr>
<td>Lithuania</td>
<td>Yes</td>
<td>Yes</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Luxembourg</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Malta</td>
<td>Yes</td>
<td>Not applicable</td>
<td>100</td>
<td>Not applicable</td>
</tr>
<tr>
<td>Netherlands</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Poland</td>
<td>Yes</td>
<td>Yes</td>
<td>99</td>
<td>100</td>
</tr>
<tr>
<td>Portugal</td>
<td>Yes</td>
<td>Yes</td>
<td>94</td>
<td>93.6</td>
</tr>
<tr>
<td>Romania</td>
<td>Yes</td>
<td>Yes</td>
<td>100</td>
<td>100</td>
</tr>
<tr>
<td>Slovakia</td>
<td>Yes</td>
<td>Yes</td>
<td>100</td>
<td>99.9</td>
</tr>
<tr>
<td>Slovenia</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Spain</td>
<td>Yes</td>
<td>Yes</td>
<td>74</td>
<td>35.4</td>
</tr>
<tr>
<td>Sweden</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>United Kingdom &amp; Northern Ireland</td>
<td>No</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Yes</td>
<td>Yes</td>
<td>89.8</td>
<td>92.9</td>
</tr>
</tbody>
</table>

Source: (ACER 2012)
3.1.3. Electricity retail markets: recent price trends

Evolution of electricity retail prices between 2008 and 2012

During the period 2008-2012 the average EU electricity retail price for the EU-27 has:

- increased for household consumers on average by 18%, from 0.1668€/kWh at the end of 2008 to 0.1966 €/kWh in the second semester of 2012,
- increased for industry consumers by 17%, from 0.1250 €/kWh to 0.1466 €/kWh in the second semester of 2012.

The countries that have experienced the strongest rise during this time period are Lithuania, Spain, and Cyprus\(^{102}\) for households, and Portugal, Latvia, and Lithuania for industrial consumers. In the case of Lithuania recent market developments and in particular the shutting down of the Ignalina nuclear power plant, which was the country’s main producer of electricity, may have impacted prices. Due to the technology used, many safety concerns were raised with regards to its functioning. The shutting down of the plant was agreed as part of the accession agreement stipulated between the country and the European Union, which in turn provides financial assistance for the decommissioning of the plant.

In the case of Portugal, significant renewable energy investments have led the country to become one of the prominent players in the field in Europe. However, the costs of these investments have been transferred to retail prices, leading to significant price increases.

Pricing situation in the 2nd semester of 2012\(^{103}\)

Figure 70 and Figure 71 show household and industry electricity prices in H2 2012. Top segments represent the amount of taxation, including VAT, while dark blue triangles show the level of prices in Purchasing Power Standards (PPS)\(^{104}\), allowing to better judge discrepancies among Member States in terms of living costs and general price levels.

The EU average electricity price for households including all taxes in H2 2012 was 0.1966 €/kWh, ranging from 0.0955€ in (Bulgaria) to a maximum of 0.2972€ (Denmark), while for industry the average electricity price it was 0.1412 €/kWh, ranging from 0.0915€ for (Finland) to 0.2732€ in (Cyprus). The highest electricity prices in Euro for both households and industry consumers are therefore found in Denmark and Cyprus, respectively.

---

\(^{102}\) Latest data available at the time of writing.

\(^{103}\) Eurostat data categorize consumers by predefined annual consumption bands. Here we have selected medium size consumers for both domestic (Band DC: 2,500 kWh < Consumption < 5,000 kWh) and industry (Band IC: 500 MWh < Consumption < 2,000 MWh) end-users.

\(^{104}\) Purchasing power standard (PPS) is an artificial common currency based on purchasing power parities derived from the GDP (gross domestic product) of each Member State.
In PPS, electricity for domestic consumers is most expensive in Cyprus, Germany, and Poland, while for industrial consumers it becomes most expensive in Cyprus, Malta, and Italy. On the other side, the lowest electricity prices in PPS are found in Finland, France, and Luxembourg for domestic consumers and in Sweden, Finland, and France for industrial consumers. Both Finland and France have a high share of nuclear electricity, which helps keeping prices low (though some argue that these prices are kept artificially low, as they do not sufficiently take into account future costs of decommissioning plants and processing nuclear waste).

\[105\text{ VAT and certain other taxes are recoverable for industry.}\]
In all configurations, retail electricity prices are found to be very high in Cyprus. It can be argued that this might be due to the high level of fossil fuel imports which constitute the bulk of energy production patterns in Cyprus (see Section 0). The same may hold for industrial energy prices in Malta and Italy, which both have a high share of oil and gas in electricity production. As a result, when analysing individual Member State profiles it will be important to take into account not only the regulatory framework and the market conditions, but also the relevant energy mix used for electricity production. More insights into the relationship between energy mix and retail energy prices will be provided in the sections below.

It is interesting to note how the situation changes when comparing between prices in Euro and PPS, which acts as an indicator of the actual price level across countries. The differences are particularly noticeable for most new Member States; their ranking is almost inverted.

Based on these data, the following observations can be made:

- The price of electricity for domestic consumers is generally higher than for industrial consumers (on average 30% across all Member States).
- The share of taxes and levies (including VAT and other taxes) for the EU-27 is on average 30% for domestic consumers and 34% for industry consumers.\(^{106}\)
- According to Eurostat (2013), between the second semester of 2011 and the second semester of 2012 Cyprus and Greece have experienced the largest price increase for domestic consumers, while Italy and Bulgaria experienced strongest price increases for the industry sector.

Cyprus’ strong reliance on oil for electricity production has obviously a direct impact on end-user prices. In Greece, the recent transition from regulated to non-regulated markets along with increased taxation hit consumers the hardest. In Italy and Bulgaria a combination of strong reliance upon energy imports and tax increases has contributed to the price increase.

**Evolution of retail electricity prices in comparison to wholesale prices (EU-15)**

Figure 72 below shows the evolution of average retail electricity prices in EU15 in comparison with wholesale prices for the main electricity power exchange in Europe (Vasa ETT 2013). According to the authors of the Vasa ETT report, EU15 countries experienced a 40% decrease in wholesale electricity prices following the 2008 financial crisis, while retail prices remained more or less stable throughout the period analysed. It can be assumed that before 2009 both wholesale and retail prices increased and readjusted to lower levels throughout 2009.

Wholesale prices were particularly volatile between September 2009 and March 2010. The high increase in wholesale prices in December 2010 was due to the very cold weather of that year in many Member States and to economic growth that increased energy demand. Cold weather affected prices in such a way that base-load prices were higher than average retail prices at different time in the winter of 2009 and 2010. In comparison, retail prices remained mostly stable throughout the period analysed, slightly decreasing between 2009

\(^{106}\) It has to be noted, though, that some taxes and levies included here, in particular VAT, are typically recoverable by industry customers; when excluding VAT and other recoverable taxes and levies, the resulting share of taxes for industry reduces to 18.3%.

\(^{107}\) Greece is not included in the analysis because of missing data.
and 2010 and increasing again throughout 2011. It seems then that wholesale price volatility is not directly transmitted to end-users.

This lack of correlation between the two is explained by the fact that electricity is mostly sold through internal procurement and bilateral contracts rather than being directly acquired through the spot market (Vasa ETT 2013). Also, retail electricity prices are mostly regulated and are adjusted only few times per year.

**Figure 72: Residential user electricity prices (EU-15 average)**\(^{108}\) versus wholesale electricity prices

![Residential end-user electricity price Vs. wholesale price](image)

**Source:** (Vasa ETT 2013)

### 3.1.4. Gas retail markets: recent price trends

**Evolution of gas retail price trends between 2008 and 2012**

During the period 2008-2012 the average EU gas price for the EU-27 has:

- increased for household consumer by 14%, from 0.0629 €/kWh to 0.0715 €/kWh at the second semester of 2012,
- increased for industry consumers by 5%, from 0.046 €/kWh to 0.0483 €/kWh.

The countries which have experienced the strongest growth during this time period are Lithuania for households\(^{109}\) and Bulgaria and Portugal for industrial consumers\(^{110}\).

---

\(^{108}\) (Vasa ETT 2013) gathers data independently from Eurostat and uses a different way of separating taxes, levies, and other charges; for that reason, absolute retail price values shown differ from the Eurostat values in Figure 70 and Figure 71.

\(^{109}\) Greece and Austria are not included in the analysis because of missing data.

\(^{110}\) Household band D2: 20 GJ < Consumption < 200 GJ and industry band I3: 10,000 GJ < Consumption < 100,000 GJ
Impact of the Oil Price on EU Energy Prices

Situation at the 2nd semester of 2012

The EU-27 average price for households\(^{111}\) including all taxes for the second semester of 2012 is 0.0715 €/kWh, ranging from 0.0274 €/kWh (Romania) to a maximum of 0.1268 €/kWh (Sweden). The EU-27 average price for industrial customers in the second semester of 2012 is 0.0483 €/kWh, ranging from 0.0327 €/kWh (Romania) to a maximum of 0.0988 €/kWh (Sweden).

Figure 73: Retail gas prices for domestic consumers

![Retail gas prices for domestic consumers](image)

Source: (Eurostat 2013)

Figure 74: Retail gas prices for industrial consumers\(^{112}\)

![Retail gas prices for industrial consumers](image)

Source: (Eurostat 2013)

\(^{111}\) Provisional data (Eurostat 2013)

\(^{112}\) VAT and certain other taxes are recoverable for industry.
Again, the analysis of data in PPS allows us to understand the actual impact on energy affordability for domestic and industrial consumers. In PPS, gas for domestic consumers is most expensive in Bulgaria, Greece, Portugal, and Hungary. For industrial consumers it is most expensive in Hungary, Bulgaria, and Lithuania. Again similar trends were identified as for electricity. Moreover, Eastern European countries seem to suffer from their proximity to Russia and a strong reliance on gas imports from the Russian giant Gazprom (see section 0 on Opera pricing).

On the other side, the lowest gas prices for consumers are found in Luxemburg while for industry the United Kingdom is still relatively cheap.

The following observations can be made:

- In comparative terms, the poorest EU countries are generally more affected by high gas prices than the more developed economies. This is mainly due to the fact that retail gas prices are substantially affected by wholesale prices, which are often higher for countries with potentially less bargaining power.
- With a few exceptions, the price of gas for domestic consumers is generally higher than for industrial consumers (on average 18% across all Member States).
- The share of taxes and levies in the gas price (on average around 22%) does not differ greatly between industry and households.
- According to Eurostat (2013), between the second semester of 2011 and the second semester of 2012 Spain (68%), Latvia (21%), Estonia (19%) and Bulgaria (18%) have experienced the largest price increase for domestic consumers, while Bulgaria (25%) and Latvia (18%) experienced the strongest price increases for the industry sector.

Evolution of retail gas prices in comparison to wholesale prices (EU-15)

Figure 75 shows the evolution of the average retail gas price for domestic consumers in EU15 in comparison to the wholesale gas market for the main European markets (Vasa ETT 2013).

As can be seen, wholesale prices decreased sharply following the 2008 economic downturn but have followed an overall upward trend ever since. The average retail price in EU-15 decreased throughout 2009 and has increased since the beginning of 2010.

Hence it can be seen that retail gas prices follow wholesale prices more closely than in the case of electricity, with only a slight delay. Obviously, retail gas prices are adjusted more often to the wholesale level than electricity prices. (Vasa ETT 2013) argue that this is based on the fact that regulated gas tariffs are usually revised quarterly, on the basis of pricing formulas that include a spot price component.

113 Wholesale energy costs also includes supplier margin, which is often not presented as a separate component.
3.2. Energy bills: main price components and drivers

Retail energy prices in the EU depend on a variety of factors, which may differ to a greater or smaller extent among Member States. In this section the study presents in details the main cost components for retail electricity and gas prices. In general, it is possible to identify three main cost components:

- **Wholesale energy costs**: corresponding to the actual cost of the gas or electricity purchased from wholesalers (for determinants of wholesale energy prices, see chapter 2). Supplier margins, i.e. the proportion of the price going to private actors in the energy chain, generating profit but also covering sales and marketing expenses, are included in this component\(^\text{114}\).

- **Network charges**: representing the cost related to the transport of electricity or gas from one point to another through necessary physical infrastructure. Energy suppliers are obliged to pay these network charges set by the national regulatory authority for the use of transport infrastructure. It should be noted that in certain cases\(^\text{115}\), a part of transmission and distribution costs is borne by wholesalers.

\(^{114}\) Consistent and comparable data on supplier margins is not readily available; for that reason, supplier margins are aggregated with the cost of the commodity in most available analyses and data sets (see e.g. London Economics 2012). The ratio between household and industrial prices reflects the different margins applied to each customer group, essentially enabled by the difference in sales and marketing cost between large and small consumers.

\(^{115}\) E.g. in cases where transmission and distribution is not yet fully unbundled and suppliers own and operate parts of the network.
• **Taxes and other charges**: including direct and indirect taxes which are included in the final retail prices. These are generally government mandated charges and can contribute significantly to the end-user price of energy.

The cost component structure of an energy bill is influenced to a lesser or greater extent by internal and external factors. Such “price drivers” determine the relative importance of each component and exemplify the linkages that exist between energy bills and the market structure. In the next sections the main cost components and key drivers for retail electricity and gas prices will be discussed. Through this analysis it is possible to determine the direct and indirect impact of oil prices on retail prices.

**Box 1: The Italian retail electricity prices for domestic consumers**

Annex E presents the detailed decomposition of electricity and gas prices for domestic consumers in Italy. The pricing structure reflects quite well the key elements presented above; however, for Italy it is possible to further split general price components into other sub-components. For instance, wholesale energy costs are identifiable in the component “production and supply costs”, which is subdivided into primary energy costs and retail costs related to the production and supply of electricity. This component accounts for 54% of the final electricity price. Also, apart from distribution and transmission tariffs defined as network tariffs (14% of the final price) another component related to the network is present and defined as “general system tariff”, accounting for 18% of the final price. In other case studies this sub-division is not available. The remaining tax component accounts for 13% of the final price in Italy.

**3.2.1. Decomposition of electricity retail prices**

The diagram below (Figure 76) outlines main drivers and price components of retail electricity prices in Europe.

**Drivers**

The drivers constitute the factors of influence through which one of several price components prices may be affected. Such drivers include:

**Energy supply structure**

The energy supply structure encompasses all activities related to the production and supply of electricity. The main factors influencing the supply structure include primary fuels and technologies used for producing electricity. The ratio of imported energy versus national sources also has an important influence. Adequate access to energy infrastructures determines the ability to diversify energy imports and reduce dependency on e.g. a single supplier.
Figure 76: Overview of the main drivers and price components of retail electricity prices in the EU

- **Energy supply structure**
  - Share of nuclear power etc.
  - Access to domestic resources / global energy markets
  - Access to infrastructures

- **Wholesale and retail market structure**
  - Degree of market liberalisation
  - Type and share of contracts (oil indexation, hub pricing)

- **Regulatory framework**
  - System and Operational charges
  - Local, national and EU regulatory environment

- **Policy**
  - Energy and Climate Change policy
  - Industrial policy
  - Economic policy

- **Wholesale energy costs**
  - Cost of primary energy
  - Capital cost (generators etc.)
  - Costs associate to trading
  - Supplier / retailer margin

- **Network Charges**
  - Technology costs
  - CAPEX/OPEX
  - Maintenance costs
  - Investments
  - Transmission/distribution charges

- **Taxes and charges**
  - VAT and other taxes
  - Price subsidies or restrictions
  - Cost associated to feed in tariffs, etc.
  - Carbon levy, ETS contribution
  - Local license fees and local taxations

**Drivers**

**Price components**

**Source:** Study authors

**Box 2: Lithuanian dependency on foreign imports**

Since the shutting down of the nuclear power plant “Ignalina” in 2009, Lithuania must rely on Russian exports for roughly 80% of its energy consumption, mostly through imports of natural gas and electricity. Moreover, along with the other Baltic states, the country has little or no physical connections to other EU Member States to diversify its energy imports. For this reason it is often referred to as an energy island. The main problem faced by the energy sector therefore relates to the high level of dependency on foreign imports due to the lack of local capacity and the difficulty in diversifying supply sources in the short term.

The case study presented in Annex E shows how retail electricity prices have recently increased, in particular due to an increase in wholesale energy costs. Due to the strong dependency on foreign imports also of electricity, it is often the case that in the Lithuanian merit order curve the marginal price in the wholesale electricity market is set by imported electricity rather than domestic production costs.

**Wholesale and retail market structure**

Wholesale and retail market structures are determined by the type and size of the market and by the key participants involved. In particular the degree of market liberalisation is an important factor explaining discrepancies at the retail level. A high level of market
concentration may reduce the number of new entrants, hence limit competition and price offers.

**Regulatory Framework**

The regulatory framework combines legislations and rules that govern the supply, transmission and distribution of electricity. The National Energy Regulator (NRA) defines the regulatory framework and operation charges. The regulatory framework establishes the conditions through which energy suppliers are able to negotiate retail contracts with end-users. The relative “degree of freedom” through which contracts are prepared is also an important factor in determining price levels. With regulated tariffs this freedom is of course highly impeded.

**Policy**

National policies, such as regarding energy security, energy efficiency, and climate change policies, may impose additional costs on consumers through corresponding charges for the promotion of new technologies or reduction of energy consumption. Other types of horizontal or transversal policies, such as those aiming to improve industrial competitiveness, may also influence price setting through specific levels of taxation for industrial consumers.

**Price components**

Price components include the different elements that when summed up constitute the final retail price to the end users. Each of these price components can be impacted directly or indirectly by the drivers seen earlier. Components of retail electricity prices include:

**Wholesale energy costs**

Wholesale energy costs include all costs associated to the purchase of fuels for electricity production or the purchase of electricity itself when imported (see detailed discussion in chapter 2). Such costs also include the cost of capital and trading. Supplier margins are also generally included under this price component.

**Network charges**

Network charges include all costs related to the transport and distribution of electricity at the low and high voltage level. Capital Expenditures (CAPEX), network expansion, Operational Expenditures (OPEX), which include infrastructure and maintenance costs, and, finally, network charges set up by the NRA are some of the components included in these costs. Metering and billing costs are also part of this component.

**Taxes and charges**

Taxes and charges include all direct and indirect taxation applied to electricity. Consumption charges such as Value Added Tax (VAT), excise duties, and environmental taxes are included here. The level and nature of charges and taxes applied vary substantially between countries.

Figure 77 shows the share of VAT and other charges across the EU for household electricity prices. The share of taxes and levies ranges from 56% in Denmark to only about 5% in the UK. The situation for the retail industry electricity price is quite similar.
Figure 77: Household electricity price breakdown for the year 2012

Source: (Eurostat 2013)

It is important to note that the Eurostat data still include e.g. network charges in the main component “energy costs”. A recent report from (Vaasa ETT 2013) on residential energy prices, estimates that the average energy price component (including retail margins) for the EU15 is only around 43% of the total final retail price of electricity, if one excludes direct/indirect taxation and network charges.

Box 3: German retail electricity price tax component

Annex E presents the detailed decomposition of retail electricity prices for German domestic consumers (volume-weighted average across all tariff categories) (Bundesnetzagentur 2013). According to BDEW (2013), electricity prices for domestic consumers have increased by 68% between 1998 and 2013. Among the individual components, taxes have tripled, while production and network charges have increased by only 11%.

Wholesale energy and network tariffs grouped together account for 45% of the final price paid by consumers, while the tax component including a number of different charges accounts for over 50% of the electricity bill. General taxes and levies as percentage of the final price, include the following sub-charges (Bundesnetzagentur 2013):

- VAT at 19%, accounting for 16% of the final price (36% of the tax component),
- A local licence fee, accounting for 6% of the final price and 14% of the tax component,
- The “Erneuerbare-Energien-Gesetz” EEG surcharge, which supports Renewable Energies, accounts for 14% of the final price (31% of the total tax component),
- The “electricity tax”, accounting for 8% of the final price (18% of the tax component),
- A small charge established under section 19 StromNEV accounting for 0.6% of the final price.

3.2.2. Decomposition of gas retail prices

Similarly to retail electricity prices, it is possible to differentiate between the same three main components of retail gas prices: the wholesale price (paid to wholesalers), network
charges, and direct and indirect taxes. While the price composition of retail gas prices follows a similar structure as for electricity, as can be seen from Figure 78, they may be affected by different drivers, and slightly different price components should be considered.

Box 4: France regulated domestic gas tariff

Annex E includes the French case study, providing basic information on the market structure of both electricity and retail gas prices. The French gas market is characterised by a high concentration at the retail level. Domestic consumers are offered a regulated tariff. The country is dependent on foreign imports for its national consumption, mostly (80% of total consumption) supplied by Algeria, Russia, and Norway. Even if non-regulated tariffs are available on the market, 86% of domestic customers remain loyal to the regulated gas tariffs provided by GDF Suez. GDF Suez tariffs are set on a monthly basis through a pricing formula that takes into account oil price indexation derived from long-term contracts, spot market rates, and fluctuations in foreign-exchange levels. Therefore the energy component in the tariff is historically heavily dependent upon oil prices. This relation seems to have slightly decreased in recent years since GDF Suez has been renegotiating its long-term contracts with suppliers (Platts 2013).

Even with a regulated tariff, primary energy cost represents the main component of the final energy bill (55%); transmission, distribution and storage costs make up for roughly 30% of total costs, and two taxes are applied. Taxation applied (including VAT) is quite low and stands for only 15% of the final energy bill.

Figure 78: Key drivers and price components for retail gas prices

Source: Study authors

---

**Policy Department A: Economic and Scientific Policy**

124

PE 518.747
Drivers

Gas supply structure
The gas supply structure comprises all activities related to the purchase, treatment, and shipment of natural gas between wholesalers and energy suppliers. The ratio between import and national sources is fundamental in determining the impact of wholesale prices at the retail level. The value of the gas imported or produced and the quality of infrastructure are all factors affecting the relative importance of this driver.

Wholesale and retail market structure
As in the example of electricity, the retail and wholesale gas market structures are dependent upon the geographic location, the number of players, and the size of the markets. The relative share between oil indexed contract and hub pricing is an important factor impacting prices at the retail level. Since price indexation still plays a role in determining wholesale prices in most EU countries, except the UK, oil prices are able to influence directly retail gas prices paid by European consumers.

Box 5: Hungarian natural gas pricing mechanism
With 38% of primary energy consumption, natural gas accounts for the largest share in the Hungarian energy mix. The country imports roughly 70% of its gas from Russia. In the Hungarian case study (Annex E), when comparing oil prices to natural gas prices, it can be observed that the wholesale gas price clearly follows the oil price. This is due to the historical pricing formula in use, whereby 60% of the natural gas price was derived from long-term oil-index contracts and 40% from spot market prices. In order to reduce the impact of oil price the ratio was inverted at the end of 2011 (MEH 2012). In comparison to wholesale prices, end user gas prices remain stable and low throughout the year, mostly due to the regulation in place (MEH 2012).

Regulatory framework
The regulatory framework encompasses all rules and legislations that govern the distribution of natural gas to end users. These are based on national and EU legislations and influence the way in which stakeholders operate and the degree of freedom they have in purchasing and supplying gas to end-users. Transmission and distribution tariffs are also determined via the regulatory framework.

Policy
Finally, energy policies and socio-economic policies shape the framework under which gas is traded on the retail market. Fiscal policies determine the taxes that are charged to the final end-users. For instance economic policies of a social nature may lead to regulation of end-users prices and a general level of energy consumption taxation. Also climate change and environmental policies have an impact on the magnitude of fees that are charged onto the consumers for the consumption of natural gas.

Price components
Wholesale energy costs
As shown in chapter 2, gas production and supply entail various costs related to the treatment, shipping, and storage of gas. These ‘hidden costs’ are included in the wholesale price and depend on the gas quality and adequate access to infrastructure.
Network charges

Network tariffs are determined by the energy regulator. Apart from transmission and distribution charges they also include storage costs. Extra costs, dependent upon the quality of infrastructures, may also be added on the basis of local or regional legislation. Metering and billing costs are also included in this component.

Taxes and charges

Natural gas is subject to a variety of taxes and charges including VAT, excise duties, subsidies to support renewable energy, and carbon taxation. The relative importance of each component depends on the policy options adopted by the individual MS.

Figure 79 shows the decomposition of retail gas prices for the example of household consumers based on Eurostat data.

Figure 79: Household consumer retail gas price breakdown year 2012

![Graph showing the breakdown of household consumer retail gas prices for 2012.]

Source: (Eurostat 2013)

Denmark, Sweden and Romania have the highest share of taxes and levies (including VAT and other charges) in the retail price. The share is lowest in the UK and in Italy, which have traditionally been significant market players for gas in Europe. This ranking holds for both domestic and industrial consumers.

3.2.3. Analysis of price components

Evolution of wholesale and retail prices

Retail electricity and gas prices in Europe are mainly composed of a non-regulated component (the wholesale energy costs) and two regulated components (network tariffs and taxes/charges). Wholesale energy costs alone are on average the largest contributor to customer's bills for most Member States analysed. It can therefore be assumed that wholesale gas and electricity prices are in a good part responsible for increases in retail prices. Through share of wholesale prices on retail prices it is possible to better define the actual impact of oil prices on end-user energy prices.

In order to better understand the impact of wholesale prices on the retail price, the evolution of the retail price with respect to wholesale prices over time is analysed. The comparison is made for Member States with different market characteristics.
As discussed above, the impact of wholesale prices on retail prices should vary depending on the level of market liberalisation, national energy mix, and availability of resources and other external factors.

According to (ECMA 2010), for some countries the relationship between wholesale and retail prices seems to be more apparent while there seems to be no direct relation for others. A similar exercise was also carried out for both the electricity and gas sectors by ACER in its Annual Report 2011 (ACER/CEER 2012). ACER used retail prices in capital cities and spot prices to make the comparison. For electricity the report finds that retail prices correlate best with wholesale prices in countries without regulated prices. Correlation there was found to be very low for all countries except Sweden, Belgium, and Finland. Similarly, for gas the analysis finds that in those countries still featuring regulated prices the correlation between wholesale and retail prices is very low. In countries where prices are unregulated, a moderate correlation can be found while the gap between wholesale and retail price has been somewhat reduced over time. The authors indicate that there are important limits to such an analysis, due to both the lack of data and the fact that using spot prices as a proxy for wholesale prices is not accurate for all countries.

Figure 80 compares the evolution of retail electricity prices, excluding all taxes and network tariffs, for a domestic consumer with spot electricity prices in the Nord Pool. As can be seen from the figure, increases in the wholesale price are almost instantaneously followed by limited increases in the domestic retail price. In the case of wholesale price decreases, however, the relation seems to be less important. Since retail electricity prices in Finland are not regulated and are partially tied to the Nord Pool a moderate to strong correlation coefficient of 0.52 appears.

**Figure 80: Comparison of electricity retail prices versus wholesale electricity prices for Finland**

![Comparison of electricity retail prices versus wholesale electricity prices for Finland](image)

**Source:** (Statistics Finland 2012), (EMV 2012)

Figure 81 below presents the evolution of retail electricity prices, excluding all taxes and network tariffs, for an average consumer and wholesale prices (in this case actual spot prices) in Italy. As can be seen the retail price follows the wholesale price quite closely. The correlation analysis shows a rather pronounced correlation coefficient of 0.63. From the figure it can also be seen that wholesale prices have started decreasing at the end of 2012. At the same time retail prices do not immediately follow the same trend.
An increase in wholesale and retail prices is noticeable during the second half of 2008, following the increase in oil prices. Since in Italy most of electricity is produced from natural gas this probably indicates that oil prices have had a delayed but strong impact on electricity prices in Italy.

Figure 81: Comparison of electricity retail prices versus wholesale electricity prices in Italy

![Comparison retail electricity prices and wholesale price - Italy](image)

Source: (AEEG 2013)

In the case of France, the high level of market concentration and the application of artificially low regulated tariffs led to important distortions in both the electricity and gas retail markets. Considering Figure 82, which compares the retail price for an average domestic consumer in France with the level of wholesale prices, the direct impact of wholesale electricity prices seems to be less apparent than in the case of Finland or Italy. The retail prices appear to be more stable over the course of the last decade. The correlation coefficient between the two is very low, only 0.12.

Along with tariff regulation, this is also explained by the important nuclear production portfolio combined with hydropower capacity, which has allowed lower than EU average electricity costs. However, the combination of increasing operating costs due to more stringent safety standards and dismantling of ageing nuclear plants, together with the increased penetration of renewable energies will most likely result in future increases in both prices and volatility of electricity prices.

Looking at the evolution of gas retail prices with respect to wholesale spot prices in the UK for two different consumer categories (see Figure 83), it is obvious that for both small/medium size to very large industrial consumers changes at the wholesale level are followed by increases/decreases in the retail price. Correlation analysis finds only a small correlation factor of 0.23 for small to medium size industry and 0.25 for large industrial clients.

In this case the impact of wholesale gas prices on retail prices is quite low. This is probably due the fact that gas in the UK is traded through internal procurement and long-term contracts, enabling energy suppliers to smooth wholesale price volatility through hedging strategies. Hence spot prices are not the most exact proxy of wholesale prices. The impact is therefore not immediate and does not reflect the real extent of the price variations.
Degree of market liberalisation

As argued above, the level of retail market liberalisation varies a lot across the EU. In some countries consumers have the possibility to choose between a large number of suppliers and tariffs (e.g. Finland, Germany), in others the choice is very limited (e.g. Bulgaria, France).
As seen in Section 3.1, Finnish electricity prices are the lowest in PPS for both domestic and industrial consumers and domestic electricity prices are 21% lower than the EU average. The high degree of market liberalisation of the retail sector with an average switching rate of 7.6% (EC 2012) promotes competition among suppliers and therefore contributes to keeping prices low. The type of contract energy suppliers are able to offer and the conditions under which these are negotiated also affects the relation between wholesale and retail prices. Since most energy suppliers are still linked to long-term contracts, it is more difficult to adjust the price offers to short term changes at the wholesale level.

This link can be shown through a specific example. Figure 84 below shows the evolution of the different types of contracts available for purchasing electricity in Finland. It appears that fixed-term contracts react faster to changes in the spot market, both price increases and decreases, relative to contracts valid until further notice (EMV 2012).

**Figure 84: Price of electricity with different contract types for Finland**

![Diagram of electricity prices with different contract types for Finland]

Source: (EMV 2012)

**Price regulation**

Retail prices in Europe still remain capped, restricted, or somehow controlled by the national regulatory authority, often under the influence of the government. Price regulation also implies that in the majority of countries only fixed price contracts are available while in others there is a mix of both fixed prices and variable price offers.

Annex E discusses how regulated tariffs have led to an important tariff deficit in Spain. This happens when regulated end-user prices are too low to allow full recovery of all costs. The same issue may also affect other EU countries in the near future. Large tariff deficit can lead to further increases in retail prices, as the regulated tariff must be increased in order to allow full cost recovery. According to French regulation, tariffs must be set at a minimum level to allow EDF full recovery of production costs. In a recently published report the energy regulator found that regulated tariffs were too low in comparison to the increase in commercial costs of EdF (CRE 2013b). The authors estimate the gap between revenue and cost to be 7.4% for blue tariff, 3.8% for yellow tariff and 1.3% for green tariff\(^\text{116}\).

\(^{116}\) The distinction between the different tariffs is presented in detailed in Annex E. The blue tariff is applied to small domestic consumers, the yellow tariff is applied to medium size consumers such as SMEs, and the green tariff is applied to large industrial consumers.
The heavily regulated tariff system, along with a subsidised production of nuclear electricity, has kept French electricity prices below the European average. However, in order to avoid large tariff deficits, regulated tariffs will have to progressively increase in the coming years (CRE, 2013b).

In the case of France, the high level of market concentration and the application of artificially low regulated tariffs led to important distortions in both the electricity and gas retail markets.

In the case of Spain, free-market suppliers offer prices that are pinned to the evolution of the regulated tariffs in order to remain competitive. As can be seen from the figure below, most prices offered by free-market suppliers are either very close to or below the regulated ‘tariff of last resort’ (abbreviated “TUR” in Spanish) with a maximum spread of 0.013 €/kWh between the lowest and highest rate. On the other hand, for consumers with no access to the TUR the spread is much smaller at 0.003 €/kWh (CNE 2012).

**Figure 85: Spread between TUR and free-market electricity prices**

![Spread between TUR and free-market electricity prices](image)

**Source:** (CNE 2012)

**The impact of the energy mix on retail electricity prices**

Countries where electricity is produced using imported fossil fuels such as gas and oil are more likely to have high retail electricity prices than those where electricity is produced with nuclear power, where the fuel (uranium) accounts for a relatively small share of total generation costs. From the detailed analysis of the individual Member States provided above, it is noticeable that France and Finland, with an important share of nuclear in their electricity mix, offer very low electricity prices for both domestic and industrial consumers. In the case of France price regulation additionally keeps prices low. In countries like Italy and Hungary, more reliant on gas for the production of electricity, energy and supply costs are far more important.
Noticeable is also the difference between industrial and domestic energy prices in the UK, most likely as a result of industrial policy to improve national competitiveness.

As mentioned above, when gas-fired power plants are price setting for electricity, the impact of oil prices is greater compared to when other energy sources such as nuclear or coal are price setting. Hence, it is possible in these cases to observe a direct correlation between retail electricity prices and oil. In the case of Italy, given the predominance of natural gas as a primary energy source for the production of electricity, natural gas price indexation to oil has an indirect impact on electricity retail prices (see Figure 86). Correlation analyses find a positive relationship between the price of crude oil and the retail price of electricity for an average household consumer (see figure below) with a correlation coefficient of 0.83.

**Figure 86: Italy comparison of oil price and retail electricity price for the period 2001–2012**

![Diagram showing the correlation between oil price and retail electricity price](image)

**Source:** (AEEG 2013)

**Network tariffs**

Network charges are established by the National Regulatory Authority (NRA) and are computed on the basis of price formulas that take into account distribution and transmission costs, the cost of operating and maintaining the network and future investments. In the case of Italy, system charges can also be included in the category “network charges”, hence increasing the relative importance of the component. Network charges may depend on a variety of factors such as the history of infrastructure investments or economic considerations. Their weight with respect to the average cost varies substantially across Member States. From the sample of Member States analysed in this study, it is concluded that network tariffs may represent on average between 20% and 30% of final retail electricity and gas prices. In most EU countries there are specific legislations that determine the main rules for setting up network tariffs both for gas and electricity. The NRA may either provide guidelines for setting up network tariffs (e.g. Germany, Finland) or set the precise level of the tariff (e.g. Italy, France) (Eurelectric 2013).
Either way, each Member State applies different types of legislation and therefore tariff levels. According to (Eurelectric 2013), network tariffs include the following components:

- Capital costs: for the investment into physical infrastructures (e.g. cables, substations, metering system etc.);
- Operation and maintenance costs: for the overall operation and maintenance of the system;
- Customer service;
- Overhead costs: corporate costs not directly linked to the operation and maintenance of the network, but associated with network service delivery.

In principle oil prices cannot have a direct impact on the level of network tariffs as these are determined according to national legal frameworks. All in all, they are to a large extent determined by the volume of energy consumed, the quality of the network infrastructure and the location of production and consumption centres. Network tariffs tend to be relatively higher in percentage for households and smaller businesses.

It could also be argued though that high oil prices have induced policy makers to promote the use of less polluting resources such as natural gas and renewable electricity. Therefore the network tariffs cost component has increased in recent years for both gas and electricity, due to the need to upgrade infrastructures in order to cope with a gradual increase in overall consumer demand, as well as technical reinforcements required for growing interconnections and to cope with growing intermittent renewable energy production. In the case of electricity, the increasing share of renewable energy production and balancing costs have had an impact on network upgrading requirements. In the case of gas, storage has become an important component.

**Taxation**

The relevant weight of taxation also plays an important role in the final energy price. The different levels of taxation across Member States are shown in detail in section 3.2.4 below.

High oil prices have contributed to the promotion of renewable energy production, which is often financed through extra charges imposed on the final consumers. As in the above case of network tariffs, high oil prices have indirectly contributed to a partial increase in the regulated components of retail prices. Depending on the regulatory system in place, these can be part of network system tariffs (e.g. in Italy) or included as an extra charge on their own (i.e. Germany). Our analysis shows that surcharges related to the production of renewable energy are an increasing share of the regulated component. In the case of Germany, the Renewable Energy Sources Act (EEG) charge is distributed to EEG plant operators. Figure 87 presents the evolution of the different electricity price components for industry in Germany. Amongst all charges the EEG surcharge increased exponentially since 1998, from 0.08 €/kWh to 5.277 €/kWh in 2012, contributing in large part to the increase in the retail price. However, the renewable energies, which are entirely marketed on the EEX electricity exchange by the German TSOs on the basis of the EEG and related regulations, are an important driver in bringing down wholesale electricity prices through the merit order. This effect is particularly visible in the industry sector production price component between 2012 and 2013 in Figure 87.
Figure 87: Evolution of the different price components for industry in Germany

Source: (BDEW 2013)

Figure 88 shows the same price decomposition for domestic households. The EEG charge is the same for both consumer categories. However, in the case of domestic consumers a wider array of charges is added on top of it, including VAT, which contributes to double the average price for domestic consumers in comparison to industrial ones.

Figure 88: Evolution of the different price components for households in Germany

Source: (BDEW 2013)
In conclusion it can be seen that the taxation and charges, particularly charges related to the promotion of renewable energy technologies, have an increasing impact on retail prices of electricity in Germany for both households and industrial consumers. Germany being a pioneer in the deployment of renewable energy technologies, it is possible that this same impact will be seen in the future in other European countries as well, particularly those who keep renewable technology high on their energy policy agenda.

3.2.4. National structures of retail electricity and gas prices

Annex E provides a detailed analysis of retail electricity and gas prices in 10 Member States, analysing different consumer categories in Europe.

The analysis was constrained by the availability, quality and uniformity of data which tends to vary substantially between EU countries. For some countries (e.g. Bulgaria and Poland) only Eurostat data were made available, while for others detailed decomposition of electricity and gas prices was made available for pre-determined consumer categories.

Member States were required to liberalise their energy retail market by July 2007, but as mentioned in section 3.1 each Member State is at different stages of the liberalisation process. For instance, the UK and Germany have fully liberalised electricity and gas markets and tariffs are deregulated; this is also the case of the Finnish electricity sector. In the majority of other countries, consumers are in theory free to select their energy retailers offering a free-market price. In practice, however, most consumers remain under regulated-tariff contracts (e.g. Bulgaria, France, Spain, Italy, Hungary, and Lithuania). For industrial users regulated tariffs persist in a small number of countries (e.g. gas in Bulgaria and France). When both regulated tariffs and free-market offers coexist, only the price decomposition of the first is available through public sources. Industrial customers directly connected to the network tend to negotiate the energy price directly with the supplier, through customised and confidential contracts. SMEs and medium size companies consuming below a certain threshold determined at the national level, are usually subject to the same pricing mechanisms as domestic consumers.

The analysis carried out in Annex E shows that on average 40 to 60% of retail electricity and gas prices are directly attributable to the actual cost of fuels. The cost of primary energy sources such as natural gas and coal thus has a major impact on final electricity prices (ECME 2010). The relative importance of other components such as regulated network tariffs, VAT and general taxes vary between Member States. Across the EU it is apparent that electricity price differences are largely driven by each Member State’s energy mix, the cost of producing electricity and the merit order curve. Several studies confirm this including the ECME Consortium (ECME 2010), which found that cross-Member State variation in household electricity prices seems to be largely driven by differences in the cost of generating electricity. In the case of retail gas prices, import prices and import dependency appear as the key drivers of price levels.

Electricity retail prices in selected Member States

Table 6 and Table 7 below present the results of the analysis carried out in Annex E for retail electricity prices for domestic and industrial consumers, respectively. Eurostat data were used in a number of countries for which detailed decomposition from national sources could not be retrieved despite contacting national regulators and public authorities.
**Table 6: Individual price components as a share of the domestic electricity retail prices for selected Member States**

<table>
<thead>
<tr>
<th></th>
<th>Wholesale energy costs</th>
<th>Network</th>
<th>VAT</th>
<th>Other taxes and levies</th>
<th>Data source</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Bulgaria</strong></td>
<td>49%</td>
<td>34%</td>
<td>17%</td>
<td>0%</td>
<td>Eurostat (2013)</td>
</tr>
<tr>
<td><strong>Finland</strong></td>
<td>45%</td>
<td>21%</td>
<td>10%</td>
<td>23%</td>
<td>Statistics Finland (2013)</td>
</tr>
<tr>
<td><strong>France</strong></td>
<td>37%</td>
<td>31%</td>
<td>15%</td>
<td>17%</td>
<td>Energy Regulatory Commission (2013)</td>
</tr>
<tr>
<td><strong>Germany</strong></td>
<td>32%</td>
<td>23%</td>
<td>16%</td>
<td>29%</td>
<td>Bundesnetzagentur &amp; Bundeskartellamt (2013)</td>
</tr>
<tr>
<td><strong>Hungary</strong></td>
<td>39%</td>
<td>36%</td>
<td>21%</td>
<td>4%</td>
<td>Energy and Public Utility Regulatory Authority (2013)</td>
</tr>
<tr>
<td><strong>Italy</strong></td>
<td>54%</td>
<td>14%</td>
<td>13%</td>
<td>18%</td>
<td>Autorità per l’energia elettrica e il gas (2013)</td>
</tr>
<tr>
<td><strong>Lithuania</strong></td>
<td>40%</td>
<td>33%</td>
<td>17%</td>
<td>9%</td>
<td>National Control Commission for Prices and Energy (2013)</td>
</tr>
<tr>
<td><strong>Poland</strong></td>
<td>41%</td>
<td>37%</td>
<td>19%</td>
<td>3%</td>
<td>Eurostat (2013)</td>
</tr>
<tr>
<td><strong>Spain</strong></td>
<td>36%</td>
<td>42%</td>
<td>17%</td>
<td>4%</td>
<td>Eurostat (2013)</td>
</tr>
<tr>
<td><strong>United Kingdom</strong></td>
<td>37%</td>
<td>23%</td>
<td>5%</td>
<td>35%</td>
<td>Department of Energy &amp; Climate Change (2013)</td>
</tr>
</tbody>
</table>

**Source:** Various, own elaboration

The analysis shows that for all countries, wholesale energy costs are the largest component of retail prices. On average, 41% of the final energy bill for domestic consumers and 59% for industrial consumers are related to wholesale energy costs. The percentage share of network tariffs vary considerably between Member States. It is on average 29% for both households and industrial consumers. For domestic consumers the network tariffs have the lowest share in Italy (14%) and the highest share in Bulgaria (34%).

German domestic and industrial consumers pay the highest taxes with an average share of 46% and 53% respectively. VAT is charged to all domestic consumers and its share varies across Member States, the minimum being in the UK (5% of the final price) and maximum in Hungary (21%). Data on supplier margin are unavailable for most Member States. Our analysis finds that supplier margins account for 3.79% of the final price in Hungary, 8.1% in Germany (including supply costs) and roughly 8% in Spain.
Table 7: Individual price components as a share of the industry electricity retail prices for selected Member States

<table>
<thead>
<tr>
<th></th>
<th>Wholesale energy costs</th>
<th>Network</th>
<th>VAT and consumption tax</th>
<th>Other taxes and levies118</th>
<th>Data source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulgaria</td>
<td>76%</td>
<td>24%</td>
<td>1%</td>
<td></td>
<td>Eurostat (2013)</td>
</tr>
<tr>
<td>Finland</td>
<td>66%</td>
<td>25%</td>
<td>9%</td>
<td></td>
<td>Eurostat (2013)</td>
</tr>
<tr>
<td>France</td>
<td>58.4%</td>
<td>18.3%</td>
<td>20%</td>
<td></td>
<td>Energy Regulatory Commission (2013)</td>
</tr>
<tr>
<td>Germany</td>
<td>36%</td>
<td>11%</td>
<td>29%119</td>
<td>24%</td>
<td>Bundesnetzagentur &amp; Bundeskartellamt (2013)</td>
</tr>
<tr>
<td>Hungary</td>
<td>63%</td>
<td>32%</td>
<td>6%</td>
<td></td>
<td>Eurostat (2013)</td>
</tr>
<tr>
<td>Italy</td>
<td>53%</td>
<td>27%</td>
<td>19%</td>
<td></td>
<td>Eurostat (2013)</td>
</tr>
<tr>
<td>Lithuania</td>
<td>43%</td>
<td>56%</td>
<td>3%</td>
<td></td>
<td>Eurostat (2013)</td>
</tr>
<tr>
<td>Poland</td>
<td>64%</td>
<td>31%</td>
<td>5%</td>
<td></td>
<td>Eurostat (2013)</td>
</tr>
<tr>
<td>Spain</td>
<td>62%</td>
<td>33%</td>
<td>5%</td>
<td></td>
<td>Eurostat (2013)</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>71%</td>
<td>24%</td>
<td>4%</td>
<td></td>
<td>Eurostat (2013)</td>
</tr>
</tbody>
</table>

Source: Various, own elaboration

As noted in the section above, market liberalisation has an impact on retail prices. In the case of Finland for instance, the large number of energy suppliers in the market encourages a high number of price offerings keeping prices low.

High dependency upon foreign imports of primary energy sources for the production of electricity may also imply higher price levels. In Italy for instance 52% of electricity is produced from natural gas with an import share of 90%, and retail prices are found to be historically high. In the case of Lithuania, electricity import prices are actually found to be the main determinant of the final electricity price. It can also be seen that for these two countries wholesale energy costs are relatively more important in the final energy bill than in other EU Member States.

Finally, taxes and charges account for an increasing share of end consumer energy bills. In particular fees related to the support of renewable energy technologies have an impact on retail prices. For the German domestic consumers 16% of the final energy price goes into feed-in tariffs for the support of renewable energy. In Poland for instance, where 90% of electricity is produced from coal, the price of electricity is expected to increase due to the increase in costs of CO₂ emissions. According to (DECC 2013) estimates, the inclusion of the Climate Change Levy (CCL) in the UK industry sector led to an increase of 3.3% in the prices of electricity. It should be noted, however, that the maturation of renewable energy

117 VAT is recoverable, consumption tax in Germany is (partly) recoverable for certain industries, notably manufacturing industries.
118 Non-recoverable.
119 Includes consumption tax and VAT.
technologies may over the long run have a lower impact on retail prices as these technologies become less expensive and thus less dependent on feed-in tariffs and subsidies. Additionally, renewable energies lower the wholesale electricity price through their almost negligible marginal cost, as explained in section 2.5.4. At the same time externalities are more and more accounted for incumbent technologies, and reflected in a more transparent manner in the final retail electricity prices. Recent nuclear projects awarded by the UK Government to the French utility led EDF consortium have shown much increased costs of electricity production due to more stringent environmental and safety standards.

**Impacts of oil price on retail electricity prices**

First of all, the impact of oil and gas price changes on electricity prices does of course depend on the share of power that is generated from oil-linked commodities. Countries that are less dependent on gas and oil (e.g. France, Poland) will be less affected than countries heavily dependent on these source of energy (e.g. Malta, Cyprus, Italy, UK), if at all.

On the one hand, the impact of the oil price on retail electricity prices is somewhat limited by the relative stability of regulated components, including network charges and taxes. As seen in the section above, wholesale electricity prices represent 40% to 50% of the total final retail electricity price, while the final price is governed by an increasing share of network tariffs, consumption charges, and other taxes.

On the other hand, it could also be argued that, indirectly, high oil prices have induced governments to promote renewable energy production, hence increasing the share of costs associated with support mechanisms for renewable energies and network tariffs.

In conclusion, it should not be forgotten that a number of Member States regulate retail electricity prices for domestic consumers, limiting the ability of retailers to pass on increased costs (whether caused by higher oil prices or not). A case in point is the example of France given in section 3.3, where abrupt changes in the wholesale market have much less of an impact on the final price paid by consumers.

**Gas retail prices in selected Member States**

Table 8 below provides the results of the retail gas price decomposition for domestic consumers presented in Annex E. Detailed information on gas retail prices is scarcer than for electricity prices, including from Eurostat, where detailed components of gas prices similar to those provided for electricity are not available. Hence for a number of countries Eurostat data from the analysis in section 3.1 were used. For these Member States it was not possible to distinguish between wholesale energy costs and network tariffs. Among countries for which detailed data were retrieved, wholesale energy costs are the largest component of retail gas prices, on average above 50%, while network tariffs vary considerably between Member States, from a minimum of 17% in Germany to a maximum of 30% in France. VAT is charged in all countries and its share varies across Member States, the minimum being in the UK at 5%.
The results in Annex E ascertain that on average the wholesale energy price shares for retail gas prices are higher than for electricity. Taking the example of Germany, only 36% of the final electricity bill of an average consumer is attributed to wholesale energy costs, but for the gas price the share is 55% for the same type of consumer. The same is true for France, where wholesale costs account for 37% of electricity bills, while the same component is 55% for gas retail prices. Though it is difficult to make a generalisation due to the lack of data, it seems plausible to assume wholesale prices and in general the structure and functioning of wholesale markets to have a greater impact on retail gas prices than on electricity. Dependency on foreign imports is also a key driver of gas retail prices. In countries like Italy and Hungary a high dependency on gas imports leads to higher prices, as import wholesale gas prices are often linked to the oil price.

Network tariffs are usually determined by the energy regulator. Apart from transmission and distribution charges they also include storage costs. The only country for which a separate storage component was identified is Italy and it accounts for only 0.8% of the final price. Extra costs may also be added on the basis of local or regional legislation (e.g. France, Italy).

### Impacts of oil price on retail gas prices

As reported in chapter 2, the main direct impact of oil prices on gas prices is through oil indexation of long-term gas contracts. Since wholesale energy costs are an important component of retail gas prices for both domestic and industry consumers (50% to 60% of the final price), oil indexation has a direct impact on retail gas prices.

---

**Table 8: Individual price components as a share of the domestic gas retail prices for selected Member States**

<table>
<thead>
<tr>
<th></th>
<th>Wholesale energy costs</th>
<th>Network/Storage</th>
<th>VAT</th>
<th>Other taxes</th>
<th>Source</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bulgaria</td>
<td>80%</td>
<td>20%</td>
<td>0%</td>
<td></td>
<td>Eurostat (2013)</td>
</tr>
<tr>
<td>France</td>
<td>55%</td>
<td>28%</td>
<td>15%</td>
<td>2%</td>
<td>Energy Regulatory Commission (2013)</td>
</tr>
<tr>
<td>Germany</td>
<td>54%</td>
<td>17%</td>
<td>16%</td>
<td>3%</td>
<td>Bundesnetzagentur &amp; Bundeskartellamt (2013)</td>
</tr>
<tr>
<td>Hungary</td>
<td>79%</td>
<td>21%</td>
<td>0%</td>
<td></td>
<td>Energy and Public Utility Regulatory Authority (2013)</td>
</tr>
<tr>
<td>Italy</td>
<td>47%</td>
<td>18%</td>
<td>10%</td>
<td>25%</td>
<td>Autorità per l'energia elettrica e il gas (2013)</td>
</tr>
<tr>
<td>Lithuania</td>
<td>82.65%</td>
<td>17.35%</td>
<td>0%</td>
<td></td>
<td>Eurostat (2013)</td>
</tr>
<tr>
<td>Poland</td>
<td>81.25%</td>
<td>18.75%</td>
<td>0%</td>
<td></td>
<td>Eurostat (2013)</td>
</tr>
<tr>
<td>Spain</td>
<td>83.75%</td>
<td>16.25%</td>
<td>0%</td>
<td></td>
<td>Eurostat (2013)</td>
</tr>
<tr>
<td>United Kingdom</td>
<td>47%</td>
<td>18%</td>
<td>5%</td>
<td>14%</td>
<td>Department of Energy &amp; Climate Change (2013)</td>
</tr>
</tbody>
</table>

**Source:** Various, own elaboration
While wholesale gas prices generally incorporate and/or reflect oil price changes as described in chapter 2, the final impact on retail prices also depends on the degree of retail market liberalisation and price regulation. The more a market is liberalised, the more a utility will be able to pass on wholesale price increases to end users (e.g. UK). At the other extreme are the countries where retail prices are fixed or heavily regulated (France and Bulgaria). However, even in such cases, retail prices tend to follow wholesale prices after some delay. Indeed, even when sustained through specific policies by National Governments, utilities cannot absorb wholesale price increases indefinitely.

As discussed earlier, wholesale gas prices determine to a large extent final retail gas prices, but there are other very important elements having an impact as well. Since taxes, network charges, and other price components may not be correlated to oil prices and tend to be more stable, they will generally help to dampen the effect of rising wholesale prices (whether linked to oil prices or not).

### 3.3. Conclusions

Despite market integration, the EU retail energy market is characterised by large disparities and differences in the price setting mechanisms and market models applied. Moreover, large discrepancies between price levels of different countries persist. The market structure and degree of market liberalisation are important factors in explaining discrepancies in retail energy prices across the EU.

In many Member States, regulated end consumer tariffs are offered with levels determined by the national regulator, which keep prices artificially low and shield consumers from oil price impacts.

Network charges, taxes, and other charges are regulated retail price components, which are independent of the supplier. They are independent of any impact of the oil price and in general passed on fully to the final consumer. Consequently, these have a dampening effect on the impact of the oil price.

The structure and functioning of wholesale gas markets have a greater impact on retail prices than in the case of electricity. While the main components of end-user prices are similar for both gas and electricity, oil price indexation has the main impact on end-user prices for gas. Hence, oil prices have a greater impact on retail gas prices than on electricity.
**4. FACTORS INFLUENCING THE OIL PRICE IMPACT**

**KEY FINDINGS**

- Factors potentially weakening the impact of oil price changes on European gas and electricity prices include: gas price de-indexation, diversification of fuels for electricity generation and diversification of gas supplies, pass through factors and time lags (for oil indexation contracts), globally increasing LNG markets, increasing US gas production, (potential) US gas exports, (potential) European shale gas production, price controls on retail gas and electricity prices, high network charges and taxes on retail energy, strengthening of the Euro and other European currencies.

- Factors potentially reinforcing the impact of oil price changes on European gas and electricity prices include: Increased global and/or European demand for gas, or reduced global and/or European supply capacity, weakening or elimination of controls on retail gas and electricity prices, lowering of network charges or taxes on retail energy, weakening of the Euro and other European currencies.

- The growth of LNG supplies has had a large impact on the characteristics of global gas markets; whereas gas markets used to be regional in nature, they are now increasingly globalised with price movements in one market (e.g. North America) having influence on other markets (e.g. Europe, Asia). In theory, this leads to a weakening of the oil-gas price linkage. However, the overall impact of LNG on European gas prices is limited by a number of factors including the high cost of LNG (liquefaction, transport, and gasification). It should also be noted that many LNG supply agreements are oil-indexed.

- The impact of US shale gas on European energy markets is especially important to monitor, since it offers the potential for significant increases in global gas supply capacity as well as for diversification of contractual arrangements, leading to downward price effects on gas as well as increased pressure to renegotiate long-term oil indexation contracts. However, other developments such as increasing demand for LNG in Asia may keep gas prices high. Recent developments in the USA indicate that future shale gas extraction may not fulfil the high expectations raised in recent years. Thus, the overall impact of US shale gas on global markets remains uncertain.

- Price controls are one of the key factors lessening the impact of oil price changes on retail gas and electricity prices. However, they are generally seen as unsustainable in the long-term. Network charges and taxes also reduce the effect of wholesale energy price changes and by extension the impact of oil price changes on retail gas and electricity prices.

- The link between oil and gas prices depends on the overall market conditions for gas, internationally, regionally and domestically. Since these market conditions are generally expected to remain tight in the future, there is little that policy can do to avert price increases.

The objective of this chapter is to review factors reinforcing or weakening the translation mechanisms of a high oil price into high prices for other energy commodities. As shown in chapter 2, such mechanisms particularly influence pricing for electricity and gas, while for coal, apart from a direct impact through the use of oil products in coal extraction and transport, other influencing factors remain vague.
Oil products, to the contrary, are by nature intimately tied to the price of crude oil to such a high degree that any other influencing factors only play a very minor role. As a result, this chapter mainly focuses on ways to address the mechanisms translating high oil prices into high wholesale and retail gas and electricity prices in Europe.

Table 9 summarises the key translation channels discussed in chapters 2 and 3, focusing on gas and electricity. Key factors that currently or potentially amplify (or weaken) the impact of these channels will be reviewed in the following.

Table 9: Mechanisms linking electricity and gas prices to oil prices

<table>
<thead>
<tr>
<th></th>
<th>Gas</th>
<th>Electricity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Direct impacts</td>
<td>Gas supply contracts incorporating oil indexation clauses</td>
<td>Use of oil-derived fuels in power generation</td>
</tr>
<tr>
<td>Indirect impacts</td>
<td>Price linkages between oil indexed supplies and gas hub supplies</td>
<td>Price linkages between oil indexed supplies and gas hub supplies, and between oil and coal prices</td>
</tr>
<tr>
<td></td>
<td>(e.g. through the influence of large wholesalers on spot markets)</td>
<td>Use of gas in power generation (when gas is purchased through supply contracts incorporating oil indexation clauses)</td>
</tr>
</tbody>
</table>

Source: Study authors

4.1. Market factors

This section reviews recent developments in international gas markets that have played an important role in influencing prices for gas and consequently electricity in Europe. The section focuses on LNG and US shale gas since these are thought to have had the most impact on the global and European gas sector.

4.1.1. LNG

LNG imports from Qatar and other countries have played a key role in European markets for some time. As confirmed by several studies (e.g. JRC 2010), the growth of LNG has had a deep impact on the structure and functioning of global gas markets; whereas markets used to be regional in nature, they are now increasingly globalized with price movements in one market (e.g. North America) having influence on other markets (e.g. Europe, Asia). For example, increasing LNG capacity in North-West Europe strengthened the link between UK and US gas hub prices between 2009 and 2010 (JRC 2012). In theory, future developments outside of Europe (e.g. a major increase in unconventional gas supply capacity in Canada or Australia) could result in lower gas hub prices in Europe. This would in turn put further pressure on wholesalers to either weaken oil indexation or at least make adjustments to reduce the gap between oil-indexed and gas-hub pricing.

However, despite the growth of LNG worldwide, several barriers make it difficult to achieve a truly “global” gas price. Above all, the high costs of liquefaction, transport, and regasification make it impossible to offer the same prices everywhere. According to (Messersmith 2012), the total costs of liquefaction, shipping and regasification in the US are between USD 2.10 to USD 3.20 per MMBtu, or about the same as the wellhead price of US gas in recent years. In other words, importers of US LNG would pay about double the price paid by domestic US buyers.
Thus, even in a fully liberalised European market, local and regional suppliers (i.e. suppliers linked to European markets by pipeline) would not be competing directly with US or Middle-East gas prices, but with the full cost of imported gas including the cost of transportation. LNG can still be attractive to European buyers, but as noted by one study (EDF Energy 2012), “once the costs of LNG transportation (and re-gasification) to Europe is taken into account, [the increasing volume of gas available worldwide] may only curb the extent of price rises in the longer-term rather than drive prices down from current levels.”

Another important point to note is that LNG is not necessarily traded under gas hub pricing arrangements. In fact, much of the LNG imported into Europe is subject to oil indexation, as is the LNG imported by Japan. After all, the rationale behind oil indexation is the same for LNG as it is for pipelines; both require costly infrastructure investments that entail a certain level of price stability and predictability, which are in turn facilitated by oil indexation. However, a key difference is that LNG suppliers have more flexibility in terms of export markets. The LNG market is effectively global; suppliers can sell to the USA, Europe, Japan, and other markets and will try to find the best price for their product. In other words, LNG exporters should be less reticent to adopt free market pricing practices since they have more flexibility to find alternate markets and thus less risk of losing money on stranded investments.

Thus, when demand for LNG is high and/or supplies are limited, prices tend to move toward those of high price markets such as Japan and continental Europe. When LNG is in oversupply, prices move toward the lowest-cost market (the USA), though, as discussed, price parity is impossible due to the higher costs of LNG relative to US domestic supplies. As noted above, the liquidity of LNG markets is therefore a key determinant of whether gas prices will be close to oil-indexed prices or not. In a seller’s market, LNG suppliers will sell at or just below either hub prices or oil indexed prices, which ever are higher. This dynamic points to the possibility that expectations regarding the impact of market liberalisation and de-indexation on low gas prices may be overly optimistic. If demand continues to grow faster than supply capacity, gas hub prices will rise, perhaps higher than what they would be under oil indexation, and LNG prices will follow. Put differently, it is not only the structure of markets and the type of contractual arrangements that determine energy prices, but also supply and demand. In a tight market, there is little that policy can do to avert price increases.

It should also be noted that the countries and regions that will benefit the most from LNG supplies are naturally those that are the closest to LNG terminals. Since the pipeline grid has capacity constraints that can cause congestion on the system, it is easier to supply buyers in proximity than say landlocked countries in Eastern Europe, who are tied to Russian suppliers (Jensen 2009).

4.1.2. The impact of US shale gas

The shale gas “revolution” in the US has four important repercussions for Europe: (1) The USA has reduced its demand for LNG, which (all other things being equal) puts pressure on global LNG prices; (2) the increase in US gas consumption has led to reduced demand for coal, which is increasingly available for export to Europe; (3) having dramatically increased its domestic production capacity, the USA could potentially export its gas to Europe and other foreign markets, which could result in further downward pressures on global and European gas prices; and (4) the US experience is encouraging countries in Europe and elsewhere to invest in shale gas.
Impact on LNG markets

The USA has dramatically reduced its intake of LNG, at a time when the global recession resulted in lower demand for gas. This has had a downward price impact on global LNG prices. However, the net effect on global and EU LNG prices is uncertain as some countries, notably Japan (after Fukushima), have been increasing LNG imports, while pipeline and LNG supplies from North Africa and the Middle-East have been disrupted by the Arab Spring. These factors, in addition to the fact that most gas contracts remain oil indexed, may explain why European hub gas prices moved away from US (Henry Hub) levels towards the higher German border price even though US gas prices were low (JRC 2012). This situation of under-supply is likely to remain for some time (UKERC 2012). That said, it is plausible to assume that current LNG prices would be even higher if the USA remained a big gas importer, and that increased imports from countries that practice gas hub pricing encouraged buyers to renegotiate oil indexation contracts. A similar trend is observed in Japan, where the government is actively seeking to move away from rigid oil indexation contracts. Throughout the world, buyers are increasingly unwilling to use oil-indexation to price gas (UK Parliament 2013).

Impact on coal markets

US power utilities have been increasingly switching from coal to gas to benefit from the low gas prices; in response, the US coal industry has been increasing its exports to Europe, which (all other things being equal) has a downward effect on coal prices and hence on electricity costs. In the current situation of relatively high gas prices, low coal prices, and very low EUA prices, gas is increasingly substituted by coal in EU electricity generation (see sections 2.4 and 2.5, and (Ritschel 2007)).

Potential for US LNG exports

In the longer term, the USA may start to export significant amounts of LNG to Europe, further exercising downward pressure on LNG prices and eventually continental gas supplies. Indeed, the US Department of Energy (DOE) is currently considering over 20 LNG export permits, which, if approved, would make the USA the largest exporter of LNG (see section 5.4.1, and (Deloitte 2013)). However, the potential for low US gas prices to translate into lower gas import costs for Europe remains to be seen; as noted above, once liquefaction, transport and regasification costs are factored in, LNG prices often approach those of Russia and other continental suppliers. Moreover, Europe will have to compete with Asia for US LNG imports, which may result in higher prices for US gas exports, all other things being equal. Finally, US shale gas reserves are uncertain and it is possible that the US will have limited surplus capacity to export in the future, being itself a major consumer of gas. A push for greater penetration of gas in transport (for use in natural gas vehicles, or indirectly, through natural gas derived hydrogen) would contribute to this.

Moreover, recent developments in the USA indicate that shale gas extraction may not fulfil the high expectations raised in recent years. US dry gas production has been constant since October 2011 as shown in Figure 89. What is more, the USA continues to be a net gas importer, and net imports of the USA having decreased because of strongly increasing shale gas production over the past few years, have remained constant since October 2012 (see Figure 90).
Impact of the Oil Price on EU Energy Prices

Figure 89: US dry gas production

Source: Study authors based on (EIA 2013b)

Figure 90: US net gas imports

Source: Study authors based on (EIA 2013b)

Impact on European shale gas development

On the other hand, the US experience is also encouraging European countries to allow shale gas exploration and exploitation, which, if successful, could support the stabilisation of gas prices, or even lead to gas price reductions. However, the potential for Europe to produce significant amounts of shale gas is highly uncertain; a more likely scenario is that shale gas is produced, but that this only helps to curb the extent of price rises rather than reduce prices.
4.2. Regulatory and political factors

4.2.1. The impact of price controls

As discussed in chapter 3, end users of gas and electricity are often sheltered from changes to commodity or wholesale prices by price controls, subsidies and other measures imposed by authorities to limit retail energy price volatility. Thus, even if oil price changes typically translate into higher wholesale gas and electricity costs, the impact on consumers may be limited. Indeed, despite the launch of the Third Energy Package and the constant push towards energy market liberalisation and integration across the EU, most EU Member States are still promoting regulated end-users tariffs. Regulated tariffs are often in place to protect specific consumer sections, mostly households, from abrupt price changes and high prices. Price regulation can take different forms. The NRA may set the level of price regularly through a pricing formula (e.g. France), which helps avoid abrupt price changes. Price caps might also be established to avoid that energy prices rise above a threshold (e.g. Italy).

Governments retain control over the price setting mechanisms often because of political considerations, fearing that removing price regulations and allowing retail prices to reflect the true costs of production could lead to price increases and public discontent. Through tariff regulation the position of the largest supplier is also favoured, hindering competition. More recently, concerns have also been raised with regards to energy affordability for energy consumers, in particular lower income households. In certain cases, governments have intervened to reduce retail prices (e.g. Hungary) and placate popular protests (e.g. Bulgaria).

Even in those countries with liberalised markets, network tariffs and taxes can account for an important share of the final price paid by consumers; according to (VaasaETT 2012), they are also responsible for recent price increases. Increases in regulated tariffs, particularly network charges, are justified by the need to improve and invest in the network system needed for the implementation of climate change policies and the integration of large amounts of renewable energy into the network system, and more generally to maintain and upgrade existing infrastructure. Price regulation and regulated components of electricity and gas prices are one of the main reasons for the large discrepancies still existing at the European level. These points are further discussed in chapter 5; the main point here is that these regulatory and political factors tend to dampen the relative effect of wholesale energy price changes and by extension the impact of oil prices changes on retail gas and electricity prices.

4.2.2. The impact of gas price de-indexation

As discussed in previous chapters, oil indexation is a major factor explaining oil-gas price linkages, and to a lesser extent oil-electricity price linkages. Would de-indexing gas prices lead to a decoupling of gas and electricity prices from oil prices, as has been observed in the USA?

Indeed, the European transition from long-term oil-indexed contracts to hub-based pricing would release gas from its dependency on oil prices. Instead of being driven by the prices of another commodity, gas prices would be able to freely react to the situation on the market. Price volatility would increase, as prices could smoothly react to changes in supply and demand. In times of low demand (e.g. in summer or in periods of high RES feed-in) prices will be lower than in periods of high demand (e.g. during cold winter / periods of low RES feed-in).
While it is true that short-term price volatility would increase, it seems that hub-prices would generally follow the trends of oil-indexed prices, albeit often at lower levels (in the British example, the move to hub-based pricing has led to lower gas prices). However, there are exceptions to this trend.

First, according to the market fundamentals, rising demand usually results in higher prices. Thus, in periods of high demand, it is entirely possible that the prices of gas traded on spot markets approach or even surpass the prices of oil-indexed gas. As shown in Figure 91, between September 2007 and January 2009, prices of spot-traded gas at the National Balancing Point (NBP) repeatedly exceeded oil-linked gas prices in continental Europe. On the other hand, gas-on-gas competition gives the possibility to apply demand response in times of high spot market prices, which is not possible with gas traded under long-term oil indexation.

**Figure 91: European oil-indexed prices vs. NBP prices**

![European oil-indexed prices vs. NBP prices](source: Heather 2013)

Second, under gas-on-gas competition, prices driven by market rules are particularly sensitive to possible supply shortages. On March 25th 2013, the UK-Belgium pipeline experienced an unexpected shutdown due to a technical problem. Gas imports into the UK were disrupted for approximately 7 hours. This incident coincided with a period of unseasonably cold weather forcing utilities to withdraw storage in order to meet demand needs. The amounts of gas available in storage facilities reached the lowest level since December 2010 prompting concern among analysts. When the operator announced shutdown of the interconnector, NBP gas prices for within-day delivery increased by more than 50%.

Third, oil and gas are no longer competing fuels in most of the OECD countries, resulting in a gradual disappearance of the price interdependency between the two fuels. This could have unexpected consequences over the medium to long-term.

---

120 Gas demand response has been discussed in the US (see e.g. Faruqui, A. and Weiss, J. Gas Demand Response, Fortnightly’s Spark 2011, [http://spark.fortnightly.com/fortnightly/gas-demand-response](http://spark.fortnightly.com/fortnightly/gas-demand-response)) and Enernoc has been running customer trials (see [http://www.greentechmedia.com/articles/read/enernoc-moves-into-demand-response-for-natural-gas](http://www.greentechmedia.com/articles/read/enernoc-moves-into-demand-response-for-natural-gas))
While their effects are difficult to quantify, the appeasement of the political situation in the MENA region, the electrification of the transport sector, or the impact of a potential “shale oil revolution” could lead to a global reduction of oil prices, and thus to a decrease in oil-indexed gas prices even if gas supply and demand would not justify a price decrease. On the other hand, if this scenario materialises, suppliers would try to renegotiate the contract formula of the long-term oil-indexed contract.

And fourth, while US hubs are supplied by numerous competing producers, the situation is very different in the EU; Europe does not only experience a rising import dependency, but its external sources of supply are mainly located in four countries. As illustrated in Figure 97, in 2011, 82% of natural gas imports originated from Russia, Norway, Algeria, and Qatar. Therefore, if (i) storage capacities are not increased, (ii) domestic production of shale gas proves to be unviable, and (iii) Europe won’t be able to attract significant LNG supplies, the transition towards a predominant hub-based pricing system could strengthen the market power of its external suppliers, especially in periods of high demand.

The European transition towards a hub-based gas pricing system will therefore not necessarily result in decreasing prices of natural gas. Under gas-on-gas competition, the price of gas will simply reflect its market value. If gas prices fell when North America and the UK liberalised their gas markets, it was at least partly due to the fact that they had substantial supply surpluses at the time (Jensen, 2009). In contrast, Jensen notes that “in times of shortage, inter-fuel competition can set prices that may be indirectly linked to oil after all.”

Moreover, price correlations between oil and gas will persist since, as discussed in chapter 2, both energy sources share common price drivers such as GDP growth. However, under the right conditions, e.g. significantly increased gas production or import capacity, and/or reduced demand, de-indexation could free gas prices to the extent where gas and oil prices could move in opposite directions, as has happened (temporarily) in the USA. Low hub prices would in turn put additional pressure on exporters of oil-indexed gas to consider de-linking gas pricing in order to protect their European markets. It should also be noted that gas price de-indexation could lead to higher volatility of gas prices (and consequently electricity prices). Price stability is one of the arguments used to justify indexation. For example, Germany, which has a high share of oil-indexed gas, has a medium to high price level but lower price volatility compared to the UK. However, oil indexation is not the only means of achieving more stable prices. For example, daily gas volatility could be reduced by using monthly price averages as a benchmark.

4.3. Other factors

There are a variety of oil indexation contracts in use; the sensitivity of gas prices to changes in the oil price depends on the type of contract. Jensen (2009) discussed the role of “pass through factors” (contractual terms that share the risk between buyer and seller) and lags between the recording of the oil price changes and their effect on the gas price. According to him, these types of contracts reduce the linkage between oil and gas prices, particularly in markets with rising oil prices. Other factors to consider when examining the relationship between global oil prices and European gas and electricity prices are the impact of trade balance, and hence currency movements, on the price paid for imported energy. A weaker currency raises the cost of imported oil, which in turn amplifies the effect of oil-gas/electricity price linkages, all other things being equal.

\[\text{121} \text{ Middle East and North Africa}\]
\[\text{122} \text{ Provisional Eurostat data for 2012 indicate no change of the situation described.}\]
For example, if an increase in the oil price leads to higher gas prices (due to oil indexation and other mechanisms), the net effect of this increase will be amplified if the country in question is experiencing a weakening of its currency. Conversely, a strengthening of the Euro or other European currencies with regards to the US dollar (the primary currency used in international oil transactions) reduces the impact of oil price increases on domestic fuel, gas and electricity prices. It follows that greater energy independence reduces the vulnerability of Member States with regards to currency related oil price movements, while also strengthening their bargaining position with foreign suppliers of natural gas. However, the question as to whether European shale gas or other developments could contribute to greater energy security remains controversial (see above).

Another potential dynamic to consider is the effect of climate change policies on power generators. On the one hand, the increased penetration of renewable energy in the power sector will lessen the dependence of power generators on gas, thus improving their bargaining power vis-à-vis their suppliers (which, for example, could result in decoupling of oil and gas prices). But on the other hand, pressures to reduce coal combustion in the power sector will have the opposite effect, since power generators must replace at least part of their coal derived electricity by consuming more gas (since fluctuating renewables are not suitable for base or peak power).

4.4. **Conclusion**

This chapter reviews various factors reinforcing or lessening the translation of high oil prices into high energy prices. In summary, the following factors could significantly weaken the impact of oil price changes on European gas and electricity prices:

- A significant increase in global LNG supplies and LNG import and regasification capacity in Europe, provided that gas demand is held constant or decreases;
- Continued increases in US domestic gas production, since this has the effect of lowering global demand for LNG;
- The (potential) development of US gas export capacity;
- The (potential) development of European shale gas production capacity;
- Price controls on retail gas and electricity prices;
- A high share of network charges and taxes in retail gas and electricity prices;
- Gas price liberalisation (through de-indexation of gas prices and/or elimination of destination clauses, etc.);
- Increased access to and diversification of gas supplies;
- Pass through factors and time lags (for oil indexation contracts);
- Strengthening of the Euro and other European currencies.

Factors that could significantly reinforce the impact of oil prices on European gas and electricity prices include:

- Increased global and/or European demand for gas, or reduced global and/or European supply capacity, since this is working against some of the factors listed above;
- Weakening or elimination of controls on retail gas and electricity prices;
- Lowering of network charges or taxes on retail gas and electricity;
- Weakening of the Euro and other European currencies.
As noted already, global and European gas supply and demand conditions are critical in determining the outcome of oil price influences on gas, and thus on electricity. In a tight gas market, there is little that policy can do to avert price increases. Thus, expectations that market liberalisation and de-indexation will necessarily lead to lower gas prices may be overly optimistic. When market conditions are tight, i.e. when demand exceeds supply capacity, gas wholesalers have no incentive to reduce their prices below that of the higher oil-indexed gas price. In other words, the impact of oil indexation is strong even though there is a significant share of hub price based contracts. Conversely, when gas supplies grow faster than demand, as happened in past years due to the USA reducing LNG imports and the fall in demand following the global recession, the gap between hub prices and oil-indexed prices (and thus the oil price) increases as gas suppliers seek to sell off their surpluses. This may result in lower gas prices for consumers. Hence, the link between oil and gas prices depends on the overall market conditions for gas, internationally, regionally and domestically.

Even if all gas transactions in the EU were based on hub pricing, there might still be a strong correlation between gas and oil prices. This might happen if LNG supplies are tight, enabling European and Russian producers to increase their prices toward oil parity (or even beyond). In a sense, proponents of electricity liberalisation faced a similar dilemma; in a free market, prices can go down under the pressures of competition, but they can also go up when demand outstrips supply. Thus, for a durable decrease in gas prices to occur, one must have not only market liberalisation and de-indexation but also continued investments in gas supply capacity. Paradoxically, some producers would argue that the high volatility and uncertainty of hub pricing discourages them from making such investments.
### 5. EVALUATION OF POLICY OPTIONS

#### KEY FINDINGS

- Many policies have the potential to contribute to reducing the impact of the oil price on energy prices in Europe. Recommendations are made in this chapter highlighting relevant policy.

- In order to avoid a direct translation of high oil prices into high energy prices, it is necessary to decouple gas from oil prices as gas prices have a significant influence on prices in the electricity and heating sector. Viable alternatives to oil-indexed gas contracts are required; these should rely on market-based price signals and reflect the actual situation of natural gas supply and demand.

- While the EU might try to accelerate the process of delinking oil and gas prices, it seems that this objective will not be achieved in a foreseeable future, notably because the majority of the exporters seem reluctant to make that move. The completion of a well-functioning, interconnected single gas market could encourage gas producers to engage in the transition to hub-based pricing. Therefore, investments in transport and storage infrastructure are required to foster the development of liquid gas hubs across the EU as part of a longer process.

- Energy taxation represents an important source of public revenues for national governments all over Europe due to the low price elasticity of energy commodities. Through the existing system of minimum excise duty governments may be tempted to partly protect consumers from oil price shocks by reducing the level of taxation when prices are high. However, this should be avoided since shielding consumers from price increases sends the wrong economic signal; end-users will not feel the price increase and thus will not adapt their behaviour.

- Energy efficiency and renewable energy sources (RES) tend to reduce fossil energy prices by reducing demand, and to weaken the impact of oil prices on electricity prices by reducing fossil fuel consumption and wholesale electricity price through the merit order curve. However, at the same time increasing fluctuating RES may increase the role of flexible natural gas fired power plants in electricity generation, and thus have a strengthening effect on the impact of oil price on energy prices as long as oil indexation remains prevalent. Furthermore, the use of RES also helps to reduce the economic impacts of high oil prices on the national economies by reducing the reliance on oil imports with related financial flows out of the country.

- Monitoring US gas production for export opportunities and facilitating the import of US LNG shipments may enhance the diversity of European gas supplies and supply contracts not directly linked to the oil price.

- Lastly, the following two potential policy options, which are controversially debated, may also have an influence on the impact of oil price on European energy prices. The deployment of carbon capture and storage (CCS) in coal fired electricity generation may allow keeping fossil electricity generation diversified and compatible with climate protection at the same time. Also, the development of innovative shale gas extraction methods may contribute to a diversification of European gas supplies while reducing environmental and health-related risks.
5.1. Completing the Internal Market to decouple gas and oil prices in Europe

In order to avoid a direct translation of high oil prices into high energy prices, it is necessary to decouple oil and gas prices as gas prices are a significant influence on energy prices in the electricity and heating sector. As a consequence, viable and accessible alternatives to oil-indexed gas contracts are required. Ideally, these alternatives should rely on a market-based price signal for natural gas and reflect the actual situation of natural gas supply and demand. Generally, more mature and competitive markets give suppliers and consumers the opportunity to develop a broader range of pricing models more appropriate to individual needs. This is also underlined in a recent discussion from the Institut français des relations internationals (Kanai 2011). It should be noted that the access to gas markets gives power generators more flexibility, not necessarily to make more profit, but to avoid generation during loss-making periods, i.e. when the power price is below their short-term generation costs.

5.1.1. The role of infrastructure in enabling wholesale markets

While in most North-Western EU Member States gas markets have already been established and are well-functioning, market liquidity is still relatively low with the exception of the NBP hub in the UK. Sufficient market liquidity is, however, an important precondition to have a well-functioning marked-based pricing mechanism. Market liquidity can be improved by increasing interconnectivity between different regional gas hubs and by removing market entry barriers for new players in order to diversify gas supply. It should be noted that low interconnectivity is not only a matter of limited physical transmission capacities but can also be a contractual issue as unused cross-border transmission capacity is not always released into the market in a timely manner. Regulators will need to address this issue.

Compared to the Member States in the North-West of the EU, the situation is very different in the remaining EU Member States, where gas hubs are practically non-existent and interconnectivity between different states is very limited. This is illustrated in Figure 92: there is no interconnection at all between Sweden and Finland, Finland and Estonia, Lithuania and Poland, Poland and Slovakia, Slovakia and Hungary, and Austria and the Czech Republic. As a result, Finland and the Baltic states are completely isolated from other EU countries and are therefore limited to largely relying on just one supplier. Also, there are no bidirectional flows between Estonia and Latvia, Poland and the Czech Republic, Austria and Slovenia, Austria and Hungary, Italy and Slovenia, Hungary and Romania, Romania and Bulgaria, and Bulgaria and Greece. Here, the first step would be to better interconnect these systems by building and increasing transmission capacities to neighbouring Member States. Financial support could be granted by the Connecting Europe Facility (see section 5.4.2). In addition, access to additional gas supplies is necessary. In (COM/2008/781), the European Commission proposed the Southern Gas Corridor initiative to access gas supplies from Middle Eastern and Caspian regions. The Trans Adriatic Pipeline (TAP) is a Southern Corridor project and is expected to transport gas from the Shah Deniz II gas field in Azerbaijan to Italy via Albania and Greece, starting in 2018. The project was chosen by Shah Deniz Consortium over the competing Nabucco West project, which proposed a different route crossing Bulgaria, Romania, Hungary, and arriving in Austria near the Slovakian border.

---

123 The route between Azerbaijan and Greece is covered by the Trans-Anatolian gas pipeline (TANAP).
The selection of TAP over Nabucco West represents a clear setback in diversifying gas supplies for these countries, as TAP allows Gazprom to maintain its predominant position in this region. But such a state of play in Central and Eastern Europe is not only due to the limited interconnection but is also linked to competition issues. To foster the development of gas hubs in this part of Europe, domestic markets need to be open to competition. DG Competition has recently launched a case against the predominant supplier in these markets, i.e. Gazprom (cf. textbox on the Gazprom case).

Another pipeline project, the North-South gas corridor, plans to connect the LNG Terminal in Świnoujście in Poland with the proposed Adria LNG terminal in Croatia. Running through central Poland, the Czech Republic, Slovakia and Hungary the North-South gas corridor will allow these countries to access new gas supplies. Since pipeline projects need a long planning time, enduring political support is crucial for the realisation of such projects.

**Figure 92: Interconnections, reverse flows in the EU-27 gas system.**

*Source: Study authors based on (Koch 2013 and ENTSOG 2013)*
Box 6: The Gazprom case

In September 2012, DG Competition launched a case against Gazprom. Essentially, it contains three allegations (Riley 2012):

1) Allegation of resale protection (destination clauses)
2) Allegation of suppression of competition in the European gas market (e.g. limited third-party access to pipelines)
3) Allegation of unfair pricing (particularly "indexation" the linking of the gas price to the oil price)

While the timeline for the case and its outcome is uncertain at this point, the three allegations provide a good summary of current competition issues in Central and Eastern Europe. Contracts with resale prohibition (or destination clauses) undermine the creation of the internal energy market. These clauses are illegal, according to the EC, as they have the potential to partition the EU single market into various national sub-markets, which is not compatible with European competition law. As a consequence, these clauses were banned from supply contracts with Western European countries at the beginning of the century but they are still present in Central and Eastern Europe. Similarly, denying third parties the possibility to access the pipeline system impedes the creation of a market and the diversification of gas supplies. The allegation of unfair pricing is related to the dominance of oil-indexed gas contracts in this part of Europe combined with the fact that there is one predominant supplier in these markets, putting the affected countries in a weak negotiation position. It is questionable whether this is acceptable under EU antitrust law or it constitutes an abuse of dominance. It should be noted that oil indexation per se would pose little risk if there were a well-functioning gas market.

Given the complexity and importance of this case, a potential prohibition decision is not to be expected before the end of 2014. A further two years will probably elapse before disposal of the main issues in the EU General Court.

5.1.2. The completion of the Gas Target Model

The completion of the internal energy market by 2014 is among the top priorities of the European Commission. Its achievement will increase the share of hub-priced gas.

In its Communication “Making the internal energy market work”, the European Commission recalled that the completion of a fluid, competitive and integrated energy market is essential to achieve the transition to a low-carbon economy (EC 2012).

It is rather difficult for a single Member State to individually achieve all of the conditions listed in the Gas Target Model (see section 2.3.4). Take the criterion on sufficiently robust markets requiring a consumption level of an entry-exit zone of at least of 20 bcm per year. In 2012, consumption exceeded 20 bcm per year in only six Member States.124 (EIA 2013). Thus, to meet all of the criteria included in the Gas Target Model, Member States are encouraged to cooperate with neighbouring countries in order to collectively establish trading regions (i.e. interconnected regional markets).

The collaboration of the Visegrád Group in this regard is a good example; at present, none of the V4 countries can solely meet the criteria included in the model. Facing similar challenges (i.e. relatively high prices, the predominance of one gas supplier, limited connectivity between the regions etc.), Poland, the Czech Republic, Slovakia, and Hungary

124 i.e. UK, the Netherlands, Germany, France, Spain and Italy (EIA 2013).
decided to commonly implement the Gas Target Model (Ascari 2013). However, the Gas Target Model also envisages the creation of a (limited) number of national market areas by the Member States which “are able to cater for a functioning market within the country itself” (CEER 2011).

Ensuring the interconnectivity of the functioning wholesale markets is another important aspect of the Gas Target Model. An efficient and transparent allocation of the capacities on the interconnection points will be of great importance. Unused capacities should be released back to the markets. These measures should facilitate gas flows throughout the system, i.e. from one trading region/national market to another (CEER 2011).

It is important to understand that the successful implementation of the Gas Target Model is preconditioned by the transposition of the Third Energy Package into national legislation by the Member States (CEER 2011). In February 2013, 16 Member States implemented the provisions of the Third Package. Member States that failed to fully transpose the directives included in the package were: Bulgaria, Cyprus, Estonia, Finland, Ireland, Latvia, Poland, Portugal, Romania, Slovenia, and the UK (EC 2013). What is more, only 4 out of 12 of the pan-European Network Codes will be finalised by 2014, i.e. the deadline for the completion of the internal energy market. The development and the transposition of Network Codes are of particular importance for the implementation of the Gas Target Model. Once developed, these Network Codes will have to be transposed into the national legislations of the Member States and will then regulate cross-border trade of natural gas.

As stated by the Council of European Energy Regulators, the concept of the Gas Target Model should be evaluated after the implementation of the above-mentioned Network Codes. ACER will be able to participate in this assessment. According to the authors of the Gas Target Model, this evaluation might lead to a readjustment of the model (CEER 2011).

The implementation of the Gas Target Model by the Member States will facilitate the creation of hubs or virtual trading points. The existence of liquid and interconnected regional wholesale markets will encourage cross-border trade of natural gas, fostering the transition to hub-based pricing reducing the direct impact of oil prices on gas prices.

5.1.3. **Policy recommendations**

Therefore, in order to avoid a translation of high oil prices into high energy prices, policy should:

- Establish well-functioning gas markets by promoting the implementation of the Gas Target Model.
- Support the process of diversifying gas supplies.
- Encourage the Member States to transpose the provisions of the Third Energy Package into national legislation.
- Interconnect and integrate regional markets.
- Promote the development and the implementation of the Network Codes.
5.2. Changes in energy taxation in Europe

5.2.1. Introduction

Taxation of energy commodities such as oil, gas, electricity, and oil products is widely practiced across the EU. Energy taxation represents an important source of revenues for Member States; oil and gas in particular represent an important source of public revenues for national governments all over Europe due to the low price elasticity of energy commodities. Taxation is also a valuable instrument for the achievement of EU renewable energy and climate change goals. Indeed, by varying the level of taxation depending on carbon content and other criteria, the EU and Member States can create incentives and disincentives to use specific forms of energy, thus promoting energy efficiency, energy security, and decarbonisation.

The EU has set up a system of minimum rates that each Member State must charge for the final consumption of energy products and electricity. Still, Member States are relatively free to determine their own legislation for both energy production and consumption. This is one of the reasons why broad discrepancies in terms of energy taxation currently subsist at the EU level, whereby the share of taxes in final electricity and gas total prices varies from 5% in the UK to over 50% in Denmark (among the EU-27).

In April 2011, the European Commission launched the proposal for a new directive (EC 2011a) restructuring the Community framework for the taxation of energy products and electricity. One of the objectives of the reform is to take into account both the CO\textsubscript{2} and energy content of energy products to promote energy efficiency and decarbonisation.

Fiscal policy measures can also help smooth the impact of oil prices on energy prices. This section identifies possible taxation amendments that could mitigate the translation of high oil prices into high energy prices.

5.2.2. Energy taxation in Europe

Taxation of energy products in Europe is commonly grouped under the definition of "environmental taxation", even though its scope is not necessarily environmental but purely fiscal. Through environmental taxation the legislator places a tax on a product or activity that damages the environment, for instance pollution, in the attempt to recover the actual costs of economic activities.

**Figure 93: Evolution of environmental taxation revenues in the EU-27 as percentage of Taxes and Social Contributions (TSC)**

![Graph showing the evolution of environmental taxation revenues in the EU-27 as percentage of Taxes and Social Contributions (TSC)](image)

**Source:** (Stamatova and Steurer 2012)
Energy taxation can take different forms; a Value Added Tax (VAT) is based on the value consumed whereas lump sum taxation is a fixed amount that is charged to the consumer irrespective of income. On top of general taxes, the most common form of taxation at the EU level is through the application of excise duties. Excise duties are a form of indirect taxation on the final consumption of an energy product, expressed as a fixed monetary amount per quantity of the product. Over the years, environmental and energy taxes have been progressively raised in the EU. In 2010 environmental taxation (including energy transport and pollution taxes) made up 6.2% of all taxes and social contribution, almost three-quarters of which are composed of energy taxes (Stamatova and Steurer 2012). Figure 93 shows that while the percentage contribution of environmental taxes to public revenues has decreased between 1995 and 2010 in the EU-27, the absolute amount of energy taxation has gradually increased in nominal terms.

As we can see from Figure 94 below, GDP has increased faster than energy tax revenues in relative terms, i.e. the share of energy tax revenues in GDP has decreased. According to (Stamatova and Steurer 2012), there are various reasons for this decline: long-term price increases in commodities such as oil and natural gas led to a slow but steady decrease in energy demand in the period between 2003 and 2010. The increase in oil price and economic crisis that took place in 2008 certainly exacerbated this trend. Promotion of renewable energies and the existence of other mechanisms (e.g. ETS scheme) may have eroded the tax basis and contributed to the decline in energy tax revenues relative to GDP. Finally, given the current economic downturn governments may have preferred not to increase energy taxation further to avoid large increases in prices for end-users.

### Figure 94: Energy taxes, GDP and final energy consumption, in the EU-27, (index 1995=100)

![Energy taxes, GDP and final energy consumption in the EU-27](image)

**Source:** (Stamatova and Steurer 2012)

In 1992, the European Community decided to start a harmonised taxation system on mineral oils through the adoption of two directives. The first one (92/81/EEC) harmonised the structure of excise duties on mineral oils, while the second focused on the approximation of the rates of excise duties on mineral oils (92/82/EEC).

Later in 2003, the EU decided to strengthen the internal market for energy products by reducing disparities between Member States and avoiding the risk of market distortions and unfair competition due to very different levels of energy taxation. For this reason, the Energy Taxation Directive (2003/96/EC) set a minimum taxation rate for energy products used as transport and heating fuels, such as oil, natural gas, coal and electricity.
The main objective of the directive was to "improve the operation of the internal market by reducing distortions of competition between mineral oils and other energy products". The Directive received much criticism especially regarding the minimum level of taxation, which was too low to be practically effective (IREF 2010).

To amend the shortcomings of the existing directive and to align energy taxation with energy and climate change targets, the EC launched a proposal to review the current energy directive on 13 April 2011. The EC proposes "to introduce an explicit distinction between energy taxation specifically linked to CO₂ (…) and energy taxation based on the energy content of the products" (COM(2011) 169/3). The proposal sets a minimum rate of €20 per ton of CO₂ related to the use of energy products (excluding electricity), while general energy consumption components (also applicable to electricity) vary depending on whether the product is used as a motor fuel (€9.6 per GJ) or heating fuel (€0.15 per GJ).

**Fiscal policy and energy prices**

Most energy taxes applied (and in particular oil taxes which represent the vast majority of energy product related taxes in the EU) fall into the excise duty category. Excise duties can limit the impact of oil prices shocks, since they vary according to volume, not price. Governments can also take advantage of this mechanism to reduce fluctuations in oil prices by keeping the rate very low when the price of oil is high and vice versa (IREF 2010).

Energy taxation may constitute 30% to 40% of the final price paid by consumers. Due to the high inelasticity of demand, taxation is an important source of public revenues across the EU. However, tax returns may fluctuate and decrease as consequence of a price increase. For example the average tax rate for oil in Europe was 40% in 1981 when the price of oil was high, while it reached 200% in 1994 when the price of oil was very low (Newbery 2005). As mentioned above, this is because the share of an excise duty is higher when the price of oil is low and lower when the oil price is high.

Increases in energy prices and in particular oil prices should not be automatically offset by a reduction in the excise duty level. Reducing the level of energy taxation can be a quick fix to protect consumers from oil price shocks, but supply and demand must be able to adjust to any permanent price increase in the medium term (Brook et al. 2004; EC 2008). To reduce the impact of fluctuating oil prices, fiscal policy should ensure that long-term oil price increases are fully accounted for in the end-user price. This way, consumers are incentivised to reduce their consumption of oil derived products, whether by using alternative energy sources or by reducing energy demand in general. It is true that consumers will be affected in the short term by higher prices, but they may even save money in the medium term. Shielding consumers from price increases sends the wrong signal to consumers (whether residential, commercial, or industrial); i.e. they will not feel the price increase and thus will not adapt their behaviour. In this sense, the proposal from the European Commission could be a valuable policy instrument for policy makers in mitigating future energy price increases and promoting the use of more efficient energy sources.

In EU Member States, there are already a few examples of ‘green’ energy levies, i.e. charges that are directly invested into the promotion of energy efficiency measures or renewable energy uptake. For example, the German Renewable Energy Act (EEG) charge on electricity for household consumers is roughly 14% of the final price. In Italy, a renewable energy and energy efficiency sub-charge is hidden within the component “general service tariff”. Both examples, however, are not taxes or duties in the strict sense – although mandated by government policy, they are raised and collected by the energy supplier. The French government has also recently announced the intention to introduce a new type of green tax for the support of renewable energies.
Impact of the Oil Price on EU Energy Prices

Putting a price on the carbon content of energy products also shifts energy consumption towards less polluting resources and, in the long term, reduces oil dependency. A few examples of carbon taxation exist in Europe: Finland for instance introduced a carbon tax as early as 1990, based on both the CO₂ content and the energy content. The tax is applied only to fossil fuels for transportation and heating, with natural gas having a reduced taxation rate in comparison to oil, while electricity is exempted.

The UK Climate Change Levy (CCL) in place since 2001 is probably the best-known example of a carbon tax in Europe. For non-domestic users, a rate of £5.24/MWh for electricity and £1.82/MWh for gas is applied (DECC 2013). The CCL attracted much attention and in particular opposition from industry which argued that taxing carbon would undermine UK’s industrial competitiveness. Notwithstanding the carbon levy and charges related to the decarbonisation of the economy, it is found that the UK actually has a very low tax rate in comparison with other Member States. A detailed study from (DECC 2013) attempts to assess the impact of energy and climate policies on end-user bills. In the analysis the authors include the impact of the Carbon Reduction Commitment (CRC), an energy efficiency trading scheme in place for private businesses and public authorities. According to their estimates, the average impact of energy and climate change policies on gas and electricity prices for medium-sized industries is between 5% and 14% of total prices. Similarly, for energy intensive industries the range of impact is estimated to be between 1% and 15% of total prices.

**Tobin tax types of instruments to mitigate speculation**

An oil future is a contract between a buyer and a seller, where the buyer agrees to purchase oil at a fixed price in the future. The contract value will vary depending on the assumptions regarding future oil price development. The debate over the role of financialization of oil futures and whether it increases the volatility of oil price is still open. Academic literature argues that oil futures impact the price of oil as they create an artificial market where the price of oil develops unrelated to actual changes in supply and demand. Investors trading oil in future markets may profit from abrupt changes in the price of oil and may exacerbate important price shocks that negatively affect end user prices (Brook, A. et al. 2004). Research found that speculation has also been related to decrease in oil prices, further contributing to price volatility (Bassam et al. 2012). A solution to reduce the impact of oil speculation is to impose a small tax on all financial transactions related to oil futures. In February 2013, the European Commission launched a proposal for the implementation of a Financial Transaction Tax (FTT) on trade, stock, and bonds exchange, backed by 11 key Eurozone countries. The rates are very low, as little as 0.1% for equities and bonds and 0.01% for derivatives, but it is estimated to raise up to €50 billion a year. Via such mechanisms speculative transactions could be reduced and therefore reduce the impact on oil prices.

**5.2.3. Policy recommendations**

Energy taxes can contribute to the stabilisation of energy prices. They should be set in a non-distortionary manner and designed to send the correct “long-term” price signal to consumers, so that they will adjust their behaviour when the price of an energy service increases or decreases (EEA 2011). Short-term quick fixes, such as reducing taxation levels when oil prices are high, may lead to market distortions. Sound fiscal instruments should provide appropriate incentives to promote an efficient use of energy resources and reduce oil dependency.

To minimize the impact of oil prices on energy prices, governments should therefore:
• Avoid energy tax reductions in response to oil price increases; if needed, short-term reductions can be applied, but these should be targeted to protect low income households only;

• Set energy taxation in such a way that it encourages consumers to lower their demand for oil products;

• Provide incentives for the use of alternative fuels in transport, thus reducing oil demand.

5.3. Energy efficiency, energy savings and renewable energies

5.3.1. Regulatory background

Energy Efficiency (EE) policy at EU level aims at reducing primary energy consumption by 20% by 2020 compared to projected consumption level. The target is non-binding.

"Energy efficiency is one of the most cost-effective way to enhance security of energy supply, and to reduce emissions of greenhouse gases and other pollutants. In many ways, energy efficiency can be seen as Europe's biggest energy resource." (EC 2011a) Indeed, a number of independent studies have confirmed that the EU has a 20% potential to reduce energy consumption economically, i.e. to generate a net financial savings effect if all necessary investments are accounted for (ECF 2010; see also Altmann et al. 2010).

In early 2011, the European Commission had an Energy Efficiency Plan describing the necessary action to achieve the 20% target “consistently with other policy actions under the Europe 2020 Strategy’s Flagship Initiative for a Resource Efficient Europe125, including the 2050 roadmap for a low-carbon economy126.” (EC 2011a).

EE policy includes a number of legislative acts that regulate different aspects of energy efficiency and energy savings127, notably in the public sector, in buildings representing almost 40% of final energy consumption, in industry, in the private consumer area, and in transport (EC 2011a):

• Energy Efficiency Directive128 (EED) adopted in October 2012, which establishes a common framework of EE measures for enhancing EE, and of rules designed to remove barriers in the energy market and overcome market failures, and provides for the establishment of indicative national energy efficiency targets for 2020. The EED requires that it be transposed into national law by 5 June 2014; notwithstanding this, specific requirements such as the reporting of national targets at earlier dates as specified in the EED need to be complied with.

• Ecodesign Directive129 adopted in October 2009 and due for revision before 2015, which provides EU-wide rules for improving the environmental performance of energy-related products.

---

126 COM(2011) 112.
127 The terms "energy efficiency” and "energy savings” are not always used consistently in the general debate. In the following, the term “energy efficiency” will be used to cover both energy efficiency in transformation processes and energy savings in final energy use.
Energy Labelling Directive\textsuperscript{130} adopted in May 2010 and due for evaluation for effectiveness by the Commission by the end of 2014, which establishes a framework for the harmonisation of national measures on end-user information, particularly by means of labelling and standard product information.

Energy Performance of Buildings Directive\textsuperscript{131} adopted in May 2010 and supplemented by Delegated Regulation (EU) No 244/2012 of 16 January 2012, establishing minimum energy performance requirements for new and existing buildings, the certification of building energy performance and requiring the regular inspection of boilers and air conditioning systems in buildings.

Construction Products Regulation\textsuperscript{132} adopted in March 2011 establishing harmonised rules on reliable information on construction products in relation to their performances.

Directive on the Promotion of Cogeneration\textsuperscript{133} adopted in February 2011 creating a framework for promotion and development of high efficiency cogeneration.

Transport-related acts notably focus on biofuels and on fuel-efficiency regulations for automobiles. The latter include the currently debated Commission proposal for a regulation\textsuperscript{134} to define the modalities for reaching the 2020 target to reduce CO\textsubscript{2} emissions from new passenger cars to 95 grams of CO\textsubscript{2} per kilometre (g/km) from the current 2015 target of 130 g/km. A similar target exists for vans. Renewable energies in transport are discussed below in connection with the Renewable Energy Directive.

Complementary action has been taken at EU level to provide financing tools for EE measures.

Future EE policy action on EU level will focus on the following aspects: As indicated above, some of the legislative acts are to be revised before 2015. In addition, there is broad consensus that the effectiveness of the EED as the core element of the European EE policy depends on the details of its transposition into national law. The EED includes a number of reporting requirements by the Member States and by the Commission with the aim of closely reviewing the progress in EE made on the basis of the EED, and to propose additional measures where necessary in order to achieve the 20% EE target for 2020.

The Renewable Energy Directive\textsuperscript{135} (RED) adopted in 2009 is the centrepiece of EU policy supporting the market development of Renewable Energy Sources (RES). The Directive defines a binding target of 20% renewable energies including electricity, heating and cooling and biofuels. For each EU Member State, an individual binding target is defined. The


recent progress report of the European Commission comes to the conclusion that “renewable energy grew strongly. The data and analysis for the renewable energy progress report shows that while the EU as a whole is on its trajectory towards the 2020 targets, some Member States need to undertake additional efforts [...]. In addition, the analysis suggests there are reasons for concern about future progress.” (EC 2013c). The Commission has opened infringement cases for non-transposition of the Directive against 12 Member States. Consequently, future RES policy action at EU level will focus on ensuring successful achievement of the 2020 RES target based on the RES Directive.

At Member State level, different renewables support policies have been implemented, allowing compliance with the targets defined in the RED. There has been an intensive and controversial debate whether these national support schemes should be harmonised at EU level in view of subsidiarity. The debate has shifted away somewhat from harmonisation towards improved coordination, cooperation and emerging best practices (Gephart et al. 2012).

In addition, the RED defines a target for renewable energies in transport: “Each Member State shall ensure that the share of energy from renewable sources in all forms of transport in 2020 is at least 10% of the final consumption of energy in transport in that Member State.” The largest share of this target was originally expected to be provided by biofuels. However, debate on competition with food and concerns about the climate impact of biofuels has led the European Commission to propose a cap to so-called first generation, i.e. crop-based, biofuels for their contribution to the 10% target. On September 11, 2013, the European Parliament passed this proposal limiting crop-based biofuels to 6%. In case this is adopted by the Council, this requires the use of other forms of renewable energies including non-crop fuels made from algae or agricultural waste as well as electricity or hydrogen to contribute more than anticipated to the 10% target.

5.3.2. Addressing the link between oil and energy prices

The 20% EE target “translates into a saving of 368 million tons of oil equivalent (Mtoe) of primary energy (gross inland consumption minus non-energy uses) by 2020 compared to projected consumption in that year of 1,842 Mtoe. This objective was reconfirmed by the June 2010 European Council [...]” (EC 2011a).

Summing up national targets set by the Member States and notified to the European Commission in accordance with article 3(1) of the EED, 2020 primary energy consumption of the EU-27 (except Slovenia, which has not notified a target) will be 1,437 Mtoe, or 22% below the projected consumption (EC 2013).

Compared to a global primary energy demand of around 15,000 Mtoe in 2020 according to the World Energy Outlook 2012 of the IEA (IEA 2013), savings of around 405 Mtoe are equivalent to 2.7% of global demand.

In general, reductions in energy demand lead to lower prices. Thus, primary energy savings lead to lower prices. And a reduction in demand for oil, natural gas, and coal through increased renewables also lead to lower energy prices. Furthermore, renewable energies put downward pressure on wholesale electricity prices through the merit order curve.

---


137 As of 19 June 2013

138 Primary energy consumption of Slovenia was 7.2 Mtoe in 2011 according to the Slovene report to the Commission according to article 24(1) EED.
It is worthwhile to qualitatively analyse the impact of demand reduction on the different fossil primary energies.

As shown by (Murray, King 2012) oil price has become rather inelastic in recent years. As a result, small changes in demand result in large changes in price. Reductions in demand for oil products, which have a very strong link both to crude oil quantities and to the crude oil price, can thus lead to noticeable reductions in oil price.

In a situation where gas prices are strongly linked to the oil price through oil-indexed contracts, demand reduction in gas will not lead to price reductions. However, if gas-on-gas competition defines gas prices, demand reductions do lead to lower prices. Therefore, breaking up oil indexation of gas contracts will allow demand reductions through EE and RES to lead to price reductions, thus enhancing the effect of moving away from oil indexation.

For coal, price reductions based on demand reductions depend on the steepness of the marginal FOB cost curve. It has been shown in chapter 2.4 that the marginal cost curve has become steeper (in addition to having shifted upwards). Further marginal costs and thus price increases are to be expected in the mid-term. Consequently, demand reductions are becoming ever more effective over time in causing price reductions, or absorbing price increases that would have occurred otherwise.

In electricity generation, price elasticity depends on the merit order curve, which itself depends on the relevant generation mix. In most Member States, natural gas-fired power plants tend to set the price during high demand times, while coal-fired plants set the price during low demand times. Reducing demand for gas during high demand times as notably done by solar PV reduces prices rather strongly. As long as oil-indexed pricing is prevalent in gas contacts, EE and RES will reduce the impact of oil price on electricity prices through this mechanism rather strongly.

On the other hand, gas-fired power plants have significantly lower investment costs than coal-fired plants. With increasing shares of fluctuating RES, power plants with low investment costs are favoured because of decreasing operating hours per year. However, in a situation where coal prices are expected to increase further in the mid-term, and assuming CO₂ prices go up again, increasing RES in electricity generation may somewhat increase the gas share in the mid-term, which is desirable both in terms of grid stability and in climate protection. Gas demand may be reduced again in the long term through the use of renewable sources for gas, i.e. biogas, synthetic methane based on bio-energies, and power-to-gas for storage purposes, replacing fossil natural gas to the extent that this can be done sustainably and in competition with gas use in heating and mobility.

Another relevant aspect of EE is that the individual consumer may still have a lower annual energy bill even if per unit energy prices increase because of the lower annual energy consumption.

### 5.3.3. Policy recommendations

In summary, EE and RES tend to reduce fossil energy prices and weaken the impact of oil price on energy prices. Only in electricity generation, an increasing use of fluctuating RES may increase natural gas relative to coal, and thus have a strengthening effect on the impact of oil price on energy prices as long as oil indexation remains prevalent. On the other hand, renewable technologies put downward pressure on wholesale electricity prices through the merit order curve, thus lessening the impact of oil price on electricity prices.
Independent of other arguments for or against renewable energies including climate protection, security of supply, and economic aspects, renewable energies thus help to reduce the impact of a high oil price on European energy prices.

Furthermore, they also help to reduce the economic impacts of high oil prices on the national economies by reducing the reliance on oil imports with related financial flows out of the country.

Therefore, in order to avoid a translation of high oil prices into high energy prices, policy should:

- Closely monitor EED transposition into national law, and take action if reviews show that the 2020 target may not be achieved.
- Use reviews of Ecodesign and Energy Labelling Directives for strengthening EE.
- Closely monitor RED development, notably target compliance and infringement cases, and take remedial action where necessary.
- Strengthen EE in transport as translation of oil price in transport fuel prices is very strong; strengthen RES in transport while strictly ensuring sustainability.

It is currently being debated whether energy goals should be set for the 2030 timeframe. In view of the positive influences of increased EE and RES on the impact of the oil price on European energy prices, EE and RES goals beyond 2020 are recommendable.

5.4. Other possible options

5.4.1. Facilitate the import of US LNG

Implementing a free trade agreement between the US and the EU\textsuperscript{139} could facilitate the import of US LNG to the EU. Experts estimate that most of the LNG produced in the USA be shipped at Henry Hub-related prices. Therefore, imports of US LNG could help reducing the impact of oil prices on EU energy prices (Henderson 2012\textsuperscript{140}). An easier access to US shale LNG would also improve the bargaining position of the EU with major gas supplying countries like Russia or Algeria.

Under US regulation, all gas export projects must be authorised by the federal government. The approval process for natural gas exports is very strict. The Department of Energy will only grant export authorisation if the proposed export is “consistent with the public interest”\textsuperscript{141} (US Department of Energy, 2013a). Such an authorisation might be granted more easily, if gas supplies were destined to a country covered by a free trade agreement.

Representatives of the US energy intensive industries express their concern that external demand will increase domestic prices of natural gas. However, according to (International Energy Agency 2012), natural gas prices in the USA will increase by $1.0/MMBtu until 2020 in a scenario where the region becomes a significant net LNG exporter. Furthermore, such a price level would be required to support gas production in the long-term.

\textsuperscript{139} The EU and the US are currently negotiating a so-called Transatlantic Trade and Investment Partnership (TTIP). It is subject to uncertainty, whether gas supplies will be covered by this (potential) free trade agreement.


\textsuperscript{141} In general, public authorities verify that the project would yield a net economic benefit to the USA, would unlikely affect the availability of natural gas and would not result in price increases or price volatility increases (US Department of Energy 2013b).
As of September 2013, only four liquefaction plants have been authorised to export LNG to countries that do not have a trade agreement with the USA\textsuperscript{142}. The total granted export capacity currently amounts to 6.37 billion cubic feet per day (bcf/d), which corresponds to 65.9 billion cubic meters per year (bcm/a) or roughly 13.3\% of the total EU natural gas demand in 2011. Based on the export contracts that have been approved so far, the main target market for US LNG is Asia and not Europe\textsuperscript{143}. This is due to the higher market price in Asia compared to Europe.

A concrete US trade policy on LNG exports seems yet to be determined. As the export capacity has reached roughly 10\% of the forecast US production rate of 69.96 bcf/d (US Department of Energy 2013d), there is a chance that public authorities will reduce the authorisation pace again in order to observe the effect of LNG exports on the domestic gas market. Uncertainties about the robustness of increasing US gas production projections in the mid- and long-term may limit the US LNG export potential.

The EU should pursue a high-level political dialogue with US authorities to facilitate imports of US LNG.

5.4.2. Support the Connecting Europe Facility

A full-scale transition to hub-based pricing will only be possible if the EU equips itself with a well-functioning network of interconnected transmission grids. The existence of a net of interconnected, regional markets is essential for the completion of a single market for natural gas, i.e. for having access to natural gas with a price not indexed to the price of oil.

The so-called "Connecting Europe Facility" (CEF) will finance infrastructure projects in order to improve Europe’s transport, energy and digital networks and to support the implementation and the development of the internal market. On 19 November 2013, the European Parliament endorsed the budget of the CEF. Between 2014 and 2020, CEF will be equipped with a budget of €29.3 billion. Nearly €5.1 billion were allotted to the energy sector. For a project to be eligible for EU (co-)funding under the CEF instrument, it must be given the status of a Project of Common Interest (PCI). PCIs also benefit from faster and more efficient permitting procedures. EU Regulation No 347/2013 provides criteria how to select a PCI. For example, a criterion can be that the project involves two or more Member States or is a cross-border project.

Efficiency and the flexibility of the gas sector can also be improved by additional gas storage facilities.

For the Connecting Europe Facility to be effective, a continuous political support and efficient allocation of budget resources is mandatory. The current budget amounts to less than 2\% of the costs incurring for grid investments in the period from 2011 to 2020\textsuperscript{144}. Therefore, additional budget cuts should be avoided.

\textsuperscript{142} Sabine Pass of Cheniere Energy in Louisiana was the first facility to be granted an export authorisation in May 2011 at a rate of up to 2.2 bcf/d. The company retrofit an existing LNG import terminal so that it could also be used for exports (US Department of Energy 2011). In May 2013, the Freeport plant on Quintana Island, Texas, was approved to export at a rate of 1.4 bcf/d. Additional export capacities of 2.0 and 0.77 bcf/d, respectively were approved in August 2013 and September 2013 for the LNG terminals in Lake Charles, Louisiana and in Calvert County, Maryland. As of December 2013, all liquefaction trains were under construction. (US Department of Energy 2013d).

\textsuperscript{143} Cheniere Energy signed a 20 year contract with Gail Ltd., India; Freeport LNG signed a 20 year contract with Toshiba, Japan.

\textsuperscript{144} According to the EU Energy Roadmap, investment costs for grid infrastructure
5.4.3. Carbon Capture and Storage (CCS)

Carbon Capture and Storage (CCS) is an important technology option controversially discussed for decarbonising the power sector, especially for coal-fired power plants. Given the rather insignificant impact of oil prices on coal prices, the availability of CCS and the deployment of coal-fired CCS power plants could limit the impact of oil prices on electricity prices.

One trend on the 2030 Climate and Energy Framework is likely to materialise: the decarbonisation of the European economy will be accompanied by an increasing deployment of electricity from RES. Albeit, the pace of RES deployment will largely depend on the existence of binding RES targets for 2030. Due to the variable production of RES, flexible generation capacities will be required to maintain a close to real-time balance between consumption and production that is mandatory for any electricity grid (Genoese and Genoese 2013).

Table 10: Flexibility of conventional power generation technologies

<table>
<thead>
<tr>
<th></th>
<th>Nuclear power plants</th>
<th>Hard coal fired power plants</th>
<th>Lignite fired power plants</th>
<th>Combined cycle gas fired power plants</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Start-up Time “cold”</strong></td>
<td>~ 40h</td>
<td>~ 6h</td>
<td>~ 10h</td>
<td>&lt; 2h</td>
</tr>
<tr>
<td><strong>Start-up Time “warm”</strong></td>
<td>~ 40h</td>
<td>~ 3h</td>
<td>~ 6h</td>
<td>&lt; 1.5h</td>
</tr>
<tr>
<td><strong>Minimal Shutdown Time</strong></td>
<td>No</td>
<td>No</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td><strong>Minimal possible Load</strong></td>
<td>50%</td>
<td>40%</td>
<td>49%</td>
<td>&lt;50%</td>
</tr>
</tbody>
</table>

Source: Eurelectric (2013)

Currently, fluctuations and load ramps are covered by conventional power plants (e.g. coal, gas, nuclear etc.) in order to safeguard the stability of the system. As shown in Table 10, among other forms of conventional power generation, (i) combined cycle gas fired power plants and (ii) hard coal fired power plants appear to be the most suitable to cover sudden load ramps, as they can be brought online more rapidly than nuclear power plants (Eurelectric 2013).

Yet, due to its high carbon footprint, it is uncertain whether coal-fired power plants will be able to remain a source of flexible generation for intermittent RES over the longer term. The future role of coal in the European power generation sector will be largely determined by the effectiveness of the EU ETS.

For the EU as elsewhere, Carbon Capture and Storage (CCS) is one of the potential technologies for decarbonising the energy sector. Because of significantly higher costs of CCS coal plants and the energy consumption of the CCS technology itself, stable CO₂ prices are a prerequisite for successful CCS commercialisation. Many scenarios for a transition to a low-carbon economy include a significant share of CCS both in the power sector and in industrial processes (EC 2013d). The EU’s strategy to ensure CCS deployment has failed to bear fruit thus far. Out of nine operating large-scale CCS demonstration projects worldwide, none is located in the EU. Additionally, there is strong public opposition against CCS in many Member States.
If the EU ETS fails to provide a robust, stable and predictable price for CO₂ emission in the EU, CCS might not become commercially viable in the EU by the 2030s. If that scenario materialises, being half as CO₂ intensive as coal, natural gas might remain the only source of flexible generation able to cost-effectively mitigate the negative effects related to the intermittent nature of RES. Therefore, if the share of gas imported to the EU under oil-indexation formulas remains robust, the prices of oil might still indirectly impact power prices. CCS technologies (particularly if applied in coal-fired plants) are thus in principle an option to limit the impact of oil price on electricity prices, and to keep fossil electricity generation diversified and compatible with climate protection at the same time.

5.4.4. Innovative shale gas extraction methods

Conceptually, innovative shale gas extraction methods could partially offset the future gas production deficit in the EU. This could reduce the impact of oil prices on gas prices, as these production volumes are unlikely to be indexed to oil prices.

Over time, the import dependency of the EU will further rise due to (i) rising consumption and (ii) declining indigenous production levels of conventional gas. By 2035, rising gas consumption in the EU is expected to reach the level of 644 bcm. By that time, conventional gas production in the EU will decline to a level of 76 bcm (IEA 2012). To close this production deficit, the EU will have to rely on imports from countries outside of the EU or the European Economic Area. If oil indexation prevails in the EU long term contracts, the price of oil might keep driving the price of gas. Domestic production of unconventional gas – assisted by reinforcing the infrastructure including storage as well as gas market design – might help in reducing this gas production deficit, partially compensating the declining production of conventional gas.

The shale gas debate in the EU involves (i) representatives of energy intensive industries calling for cheaper prices of gas, (ii) Member States willing to diversify their supply sources, and (iii) environmentalists. Shale gas controversies are mainly related to the technologies applied in the extraction process (i.e. hydraulic fracturing), risks of ground water contamination, and the potential danger of undesired leakages of methane (Dreyer and Stang 2013). Moreover, different geological conditions (shale formations in Europe are often located deeper than in the USA), stronger environmental standards and higher drilling costs are increasing the costs of production in the EU. Therefore, a shale gas “revolution” is unlikely to be reproduced on a European scale. On the other hand, shale gas extraction might increase the security of supply of certain Member States, thus helping them in meeting the criteria of the Gas Target Model (KPMG 2012).

Differences related to geology and environmental standards could push energy companies to develop new extraction technologies. Providing R&D support for innovative shale gas extraction technologies could be considered. For example, the deployment of a technology using compressed CO₂ for shale gas extraction might allow more sustainable shale gas exploration (additionally, such a technology could foster the deployment of CCS technologies, as captured CO₂ would be stored in the production processes). Finally, if successfully developed, such technologies could then be applied commercially in other parts of the world, for example where shale basins are located in water-scarce regions (e.g. in China, Algeria etc.) (Gao 2012).

145 Among the environmental concerns for hydraulic fracturing are: water pollution and undesired seismic activities.
5.5. Summary: Towards a full decoupling of oil and gas prices?

While the EU might try to accelerate the process of delinking oil and gas prices, it seems that this objective will not be achieved in a foreseeable future.

Despite the fact that Statoil appears to be gradually moving away from oil-indexation in their gas contracts, Algerian, Qatari and Russian suppliers seem reluctant to make that move. It is worth noting that nearly 54% of EU gas imports originate from these three countries (see Figure 97 in Annex A).

The completion of a well-functioning, interconnected single gas market could encourage gas producers to engage in the transition to hub-based pricing. Therefore, investments in transport and storage infrastructure are required to foster the development of liquid gas hubs across the EU. However, the deployment of new infrastructure will be timely and costly; although effects will not be immediate, these investments should be considered as part of a longer process.

Another possibility to decouple oil and gas prices could be the promulgation of longer-term contracts at fixed gas supply prices. Under this type of contract, the price of gas remains fixed for a given period of time (IEA 2012d). Whereas the duration of the contract and the price of gas are negotiated between the contracting parties, fixed-price contracts are usually applied over relatively short term periods of time. Nevertheless, if applied in long-term gas contracts, this pricing system could not only effectively limit the impact of oil on gas prices, but also provide the desired security of demand for gas producers. However, it is worth to mention three major drawbacks. First, fix-priced contracts do not represent the “real value” of gas that can change drastically over a period of 10-15 years. As explained earlier, the price of gas is certainly influenced by production costs but usually dominated by the value of gas or that of competing fuels or commodities. Second, gas supplied under a long term fixed price contract could prove to be more expensive than gas traded under a market-based pricing mechanism. Third, bound by long-term contracts, gas buyers would not be able to smoothly switch to new (potentially) cheaper substitute fuels. Therefore and for the abovementioned reasons, such a contract setup is likely to face major criticism, limiting their use to shorter periods of time. A more likely scenario is that long-term contracts with alternative indexation formulas will gain acceptance. Instead of being linked to the price of oil or oil products, the price of gas would be linked to the price of gas traded at hubs. Such a contract would give producers demand security and consumers a more flexible pricing mechanism following the “real value” of gas. Admittedly, the cost-efficiency of such contracts would largely depend on the liquidity of gas hubs.

While the imports of US LNG into the EU should be facilitated, their importance should not be overestimated. At present, only one liquefaction plant is operating in the USA. Four other terminals are currently under construction. The last of them should become fully operational by the end of 2017. Jointly, the five facilities will be capable of liquefying about 26.9 bcm per year (IGU 2013b). Considering the current US liquefaction plants and the ones under construction, even if all US LNG exports in 2020 were to be hub-priced and shipped exclusively to the EU, they would not be able to cover a mere 5% of the total EU gas demand in 2020 (IEA 2013b).

Whereas it is unlikely that shale gas produced in the EU will be indexed to oil prices, it is equally unlikely that it will be able to carry the European markets towards a hub-based pricing system; shale gas will at best be able to compensate the decreasing intra-EU production of conventional gas. Moreover, the potential role of unconventional gas in the future EU energy mix hinges upon its economic and environmental viability (Teusch 2012).

To summarise, while a full decoupling of oil and gas prices is not foreseeable in the near future, it is to be expected that Europe will be gradually moving towards hub-based pricing. While this transition will be forged by various factors, it appears that the speed of this transformation could benefit from an effective implementation of a single market for natural gas.
5.6. Putting policy options into perspective

Many policies have the potential to contribute to reducing the impact of the oil price on energy prices in Europe. The strongest impact is through oil-indexed gas contracts linking gas prices to the oil price. All measures targeted at reducing oil indexation will thus make contributions towards a decoupling of EU energy prices from the oil price. However, the extent to which different policy options have the potential to contribute to reduced oil indexation, and the speed at which effects take place, requires detailed analyses, which are beyond the scope of the present study.

Parallel developments of gas spot prices and oil prices show that the two fuels have certain price drivers in common. When both markets are decoupled and prices develop individually, four different scenarios are possible: oil and gas prices increase or decrease in parallel, or oil and gas develop in opposite directions.

In essence, the challenges of indexation are linked to the evolution of oil prices and gas prices on the market. The market situation since 2010 is characterized by high oil prices and lower gas spot prices compared to indexed prices. However, a relaxing of the oil market and a tightening of the gas market can reverse this situation. Reduced oil indexation, e.g. by indexing to the hub price of gas instead of oil, is therefore not a guarantee for lower prices in the future, although currently it is more favourable\textsuperscript{146}. Policies promoting energy efficiency and renewable (domestic) sources of energy reduce the import dependency of Europe, and reduce fossil energy demand on the global market. Both have positive economic consequences, and both reduce the impact of the oil price on EU energy prices. However, in the short-term, their impact on the translation of oil prices on European energy prices may be rather limited in quantitative terms. The European 20% energy savings target until 2020 can be achieved at net cost savings for the investors of efficiency measures and reduces CO\textsubscript{2} emissions, thus providing multiple synergies. In the long-term, energy efficiency and a high share of renewables will practically eliminate the impact of the oil price on energy prices entirely.

In addition to promoting renewable energies, many different policy options can support the diversification of energy sources. Most notably, new gas infrastructures will allow certain Member States to diversify their supply base from the current monopoly situation, and will increase the liquidity of gas hubs. As infrastructure development is a slow process, this option will not have large impacts in the short-term.

Energy taxes are an important source of income for public budgets, and provide for an important instrument to influence energy consumption and choices of energy carriers. Furthermore, energy taxes allow stabilizing energy prices of final consumers while ensuring price signals to be felt. Higher energy taxes limit the relative impact for consumers of unexpected increases in energy prices\textsuperscript{147}, while giving incentives for an efficient use of them.

In conclusion, the set of policy options available for reducing the impact of oil prices on European energy prices is large. Most of these policies will have other desirable effects in addition, including increasing security of supply, supporting climate protection, improving the competitive situation of European industry, creating employment etc.

\textsuperscript{146} Various alternatives to oil indexation exist, including but not limited to indexation to gas hub prices as discussed in section 2.3. Alternatively, contracts could be short-term rather than long-term, which includes the flexibility of the buyer to change the supplier, but includes a high level of uncertainty of the long-term demand for suppliers and thus reduces the incentive to invest in capital intensive pipeline projects. Long-term fixed-price contracts have a high predictability of prices, but include the risk of changing market conditions such as the availability of lower prices substitute fuels.

\textsuperscript{147} In a high energy retail price environment, absolute price jumps represent lower relative changes than in a low price environment. As relative changes are relevant to final consumers rather than absolute changes higher taxes (leading to higher retail prices) protect consumers from price jumps even if taxes are not reduced at this moment.
REFERENCES


DECC (2013): "Estimated impact of energy and climate change policies on energy prices and bills, Department of Energy and Climate Change March 2013.


Impact of the Oil Price on EU Energy Prices


Impact of the Oil Price on EU Energy Prices


• ENTSOG (2013): The European Natural Gas Network (Capacities at cross-border points on the primary market), July 2013.


• euracoal (2011): European Association for Coal and Lignite AISBL (EURACOAL): Coal industry across Europe 2011, Belgium, September 2011.


Impact of the Oil Price on EU Energy Prices

- Eurostat (2013g): Eurostat – European Commission: Market share of the largest generator in the electricity market http://epp.Eurostat.ec.europa.eu/tgm/mapToolClosed.do;jsessionid=9ea7d07d30df6b9b08c626a494799649ca0ff2ecff1.e34MbxeSaxa5c40LbNmBxeNaNaNeO?tab=map&i18n=1&plugin=1&language=de&pcode=ten00119&toolbox=types, download: 01.08.2013.


Impact of the Oil Price on EU Energy Prices

- MEH (2013): Data provided by the Hungarian Energy Office.
• Pieterse, W., Correljé, A. (2008): Netherlands Institute of International Relations; Crude oil demand, refinery capacity and the product market: Refining as a bottleneck in the petroleum industry.


• Renda, A. et al. (2013), Assessment of cumulative cost impact for the steel and the aluminium industry, 31 October 2013.


• Stamatova, S., Steuerer, A. (2012): Environmental taxes account for 6.2% of all revenues from taxes and social contributions in the EU-27, Environment and energy, Statistics in focus 53/2012.


ANNEX A: MARKET FUNDAMENTALS OF NATURAL GAS

Principal characteristics

The composition and quality of natural gas varies depending on the place of origin. Before natural gas can be used commercially, it must undergo a process to remove undesirable components. After processing, natural gas fulfills the characteristics of a search good as the calorific value (i.e. the heating value) and other parameters affecting distribution and combustion can be readily measured at the delivery point, limiting transaction costs. The composition of natural gas (which determines its heating value) may be changed to fit transport purposes (LNG) or end-use requirements.

Natural gas is a combustible fuel and cannot be recycled. However, following non-energy use, especially when gas is used as a feedstock for chemical products, these products may be recyclable. Gas production (extraction) sites cannot be readily converted to extraction of other commodities. Gas is sometimes a by-product of oil production (associated gas). Gas production companies are often also involved in oil extraction activities (horizontal integration). Natural gas processing plants cannot be easily converted and, even though the treatment process is less complex than for oil products, the separation of natural gas from water and other hydrocarbons may require different treatment processes and ad hoc equipment.

Depending on the transportation distance, natural gas is transported either via pipelines or as LNG. For short distances, trucks are also a viable option to transport natural gas. LNG is natural gas cooled down to approximately -160° Celsius. Once liquefied, its volume is about 0.17% that of gaseous natural gas, meaning its energy density is about 600 times higher. Furthermore, LNG weighs merely 45% of the equivalent volume of water (IEA, 2004). This gives LNG a volume and weight advantage, making it easier to store and transport. However, liquefaction facilities are more capital intensive than pipelines. Moreover, storage facilities are required both after liquefaction at the exporting terminal as well as before regasification at the importing terminal. Therefore, the transportation costs of LNG are mainly determined by the investment costs and only increase moderately with increasing transportation distance. This is why LNG is typically used to supply very distant markets (e.g. to transport natural gas from Qatar to the EU or to Japan).

Compressed natural gas (CNG) is natural gas compressed to a higher pressure (usually 220 bar) and stored in containers designed for that purpose. It is used as a fuel for road (mainly public transport) and increasingly maritime transport. Its volume is approximately 0.4% that of natural gas at standard pressure (thus its energy density is around 250 times higher).

---

149 Natural gas "comprises gases, occurring in underground deposits, whether liquefied or gaseous, consisting mainly of methane. It includes both 'non-associated' gas originating from fields producing hydrocarbons only in gaseous form, and 'associated' gas produced in association with crude oil as well as methane recovered from coal mines (colliery gas)" (IEA, 2004).
150 Consequently the average calorific value of natural gas varies across countries (all in mJ/cm): Netherlands 35.40, Russia 37.83, Algeria 39.17 and Norway 42.51. For 2009, the IEA (Golden Rules, 2012) estimates the global average gross calorific value of natural gas at 38.4 mJ/cm (at 15°C at a pressure of 101.325 kilopascals).
151 When the characteristics of a product (e.g. its heating value) can easily be evaluated before purchase, in economics the product is typically referred to as search good.
152 Also, "the composition of LNG is usually richer in methane (typically 95%) than marketable natural gas which has not been liquefied. [...] Calorific values for re-gasified LNG range from 37.6 mJ/cm to 41.9 mJ/cm" (IEA, 2004).
Supply-side characteristics

Production of natural gas has more than tripled since 1970, and it continues to grow as new sources are explored and new technologies improve extraction practices. In 2012, global production amounted to 3,364 bcm – of which, however, only 4.4% (i.e. 150 bcm) were produced within the European Union and the trend is declining.

As illustrated by Figure 95, the most important gas producing countries globally were the United States (681 bcm, 20.4% of global production) and Russia (592 bcm, 17.6%). The third and fourth largest producers are located in the Middle-East, namely Iran (4.8%) and Qatar (4.7%). The most notable producing countries in the EU are the Netherlands (1.9%) and the United Kingdom (1.2%). Except from Russia, the largest gas producers in the EU neighbourhood are Norway (3.4%) and Algeria (2.4%).

Figure 95: 2012 World gas production by region (in bcm)

Natural gas is not a scarce resource. Technically recoverable natural gas resources are still abundant – totalling 790,000 bcm. At 2011 levels of gas consumption, these resources would be sufficient to meet world gas demand for the next 235 years (compared to 185 years for oil). Eastern Europe/Eurasia (mainly Russia) and the Middle East together hold 58% of the remaining conventional gas resources, but only 17% of the remaining unconventional gas resources.


153 All data from BP, Statistical Review of World Energy, 2013; the figures have been cross-checked with IEA data for consistency. Yet, BP data is reported as it is readily available also at country level, whereas the IEA only provides this data for the larger producers.

154 This is, of course, a rather crude estimate, as demand is expected to rise in the future, technically recoverable does not mean economically and environmentally viable, and resource estimates are generally quite uncertain, especially in non-OECD countries. These figures are compared to oil with a view to the discussion of the benefits of drawbacks of oil-indexation.
Table 11: Remaining technically recoverable natural gas resources by type and region, end 2011 (in tcm)

<table>
<thead>
<tr>
<th>Region</th>
<th>Total Conventional</th>
<th>Total Unconventional</th>
<th>Tight Gas</th>
<th>Shale Gas</th>
<th>Coalbed methane</th>
</tr>
</thead>
<tbody>
<tr>
<td>E. Europe/Eurasia</td>
<td>131</td>
<td>43</td>
<td>10</td>
<td>12</td>
<td>20</td>
</tr>
<tr>
<td>Middle East</td>
<td>125</td>
<td>12</td>
<td>8</td>
<td>4</td>
<td>-</td>
</tr>
<tr>
<td>Asia/Pacific</td>
<td>35</td>
<td>93</td>
<td>20</td>
<td>57</td>
<td>16</td>
</tr>
<tr>
<td>OECD Americas</td>
<td>45</td>
<td>77</td>
<td>12</td>
<td>56</td>
<td>9</td>
</tr>
<tr>
<td>Africa</td>
<td>37</td>
<td>37</td>
<td>7</td>
<td>30</td>
<td>0</td>
</tr>
<tr>
<td>Latin America</td>
<td>23</td>
<td>48</td>
<td>15</td>
<td>33</td>
<td>-</td>
</tr>
<tr>
<td>OECD Europe</td>
<td>24</td>
<td>21</td>
<td>3</td>
<td>16</td>
<td>2</td>
</tr>
<tr>
<td><strong>World</strong></td>
<td><strong>421</strong></td>
<td><strong>331</strong></td>
<td><strong>76</strong></td>
<td><strong>208</strong></td>
<td><strong>47</strong></td>
</tr>
</tbody>
</table>

Source: (IEA2013)

While there are only limited conventional natural gas resources left in OECD countries, discoveries of unconventional resources (especially shale gas) have radically changed the picture. This holds particularly true for the United States (mainly shale gas), Canada and Australia (coalbed methane), but also potentially in the future for China (huge shale gas resources) and India. The EU also has some shale gas resources (in Poland, France, the United Kingdom and Ukraine, for example), but it is not yet clear to what extent their extraction will be commercially and environmentally viable.

Even if one applies the narrower concept of “proven reserves”, global reserves would still suffice to keep the 2012 level of production for another 56 years (compared to 45 years for oil) (BP 2013). The reserves-to-production ratio for the EU is 11.7 years (12 years for oil). For the US it is 12.5 years (11 years for oil), reflecting the remaining uncertainties regarding to long-term economics of its vast unconventional resources.

As a result of the abundant remaining natural gas resources and reserves, supply-side elasticity to demand is fairly high in the long term. However, for producers it may be difficult to adjust production levels upwards at short notice (a lengthy permitting process, exploratory seismic work may be needed, drilling and connecting wells to pipelines will take time, etc.). Downward adjustment is sticky as well (reservoir and wellbore characteristics would often not allow simply restarting production later; associated gas depends on combined oil and gas business case).

**Demand-side characteristics**

Natural gas is a major energy source, representing some 22% of the world energy demand (IEA 2013). The global demand for gas is projected to rise in the future, at a compound annual growth rate of 0.7-1.9% between 2010 and 2035, depending on the scenario (IEA 2013). Most growth will, however, come from non-OECD countries due to their higher rates of economic growth and currently underdeveloped gas markets.

---

155 I.e “those quantities that geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions” (BP 2013). Reserves estimates are in general not reliable, especially in non-OECD countries, because they may not account for upcoming developments in new technologies and exploration techniques (or other external factors) for extracting conventional and especially unconventional gas.
Against this background, it seems worth noting that while the world might be entering into a “golden age of gas”, the EU may be drifting on a different course. In several mainstream decarbonisation scenarios, the EU natural gas demand is to decline in absolute terms, even though its relative share in the energy could remain roughly at today’s levels. Natural gas is already under pressure at the moment as the low price of CO2, in connection with low coal prices, means that coal is effectively pushing out natural gas of the European power mix, possibly leading to a “dark age of gas” in Europe if climate policies prove unable to set durably a high CO2 price signal.

Figure 96 demonstrates that, while sectorial gas use varies by region, power generation is generally the largest consumer of natural gas. Natural gas is also used in buildings (mainly for space and water heating), in industry (e.g. steel, glass, paper, fabrics, brick), in energy sectors other than power generation (oil and gas industry operations), for non-energy use as a raw material (e.g. paints, fertiliser, plastics) and in transport (natural gas vehicles).

**Figure 96: 2011 World sectorial gas demand by region (in bcm)**

Due to its limited gas supply, the EU has to import some 65% of its gas, and this import dependency is expected to grow in the future, irrespective of domestic shale gas developments (Figure 97).
Figure 97: EU imports of natural gas in 2011 and their share in total consumption compared to oil

Source: European Commission, 2013
Note: Russia includes gas from other countries exported through Russia to the EU.

Generally, the long-term demand elasticity to price is relatively high due to the large number of substitutes available for natural gas (nuclear, hydro, coal or renewable energies). However, elasticity is lower in the short-term due to significant investments required for a fuel switch (different power plants, different heating system, etc.) and long lead times (especially nuclear power). Elasticity in the power sector is higher if spare capacity is high and/or trade is possible, such as is the case in the interconnected EU electricity market.

Long-term drivers causing changes in gas demand are related to “policy, geopolitics, economics, technology and environmental concerns” (IEA 2012b). The International Energy Agency has identified the following key drivers (IEA 2012b):

- Access to supply and infrastructure (availability of gas, fuel production from other sources, upstream and downstream infrastructure, distribution networks).
- Economic development (increased gas consumption due to increased demand for heating, electricity, and industrial goods).
- Competitiveness of natural gas prices versus other sources (e.g. coal, nuclear, biogas, hydrogen).
- Environmental impact of using other forms of energy (greenhouse gas emissions, which, if internalised, also affect the competitiveness of natural gas vis-à-vis other sources).
- Changes in technology (efficiency in power generation or combustion processes, electric heating, natural gas vehicles).

Applied to the EU context, natural gas demand is affected by the level of economic development of a given Member States or region (e.g. higher gas consumption in more prosperous regions such as North-Western Europe). It is also affected by policy decisions at EU, which particularly matter when they affect the competitiveness of natural gas vis-à-vis its substitutes, e.g. in the field of environmental policy (e.g. EU Energy and Climate Change Package, Large Combustion Plants Directive), for example, as well as industrial and innovation policy (Renewables Directive, direct government spending toward innovative technologies e.g. by means of the NER 300 programme of the EU). The national level is
highly relevant as well, as governments have different energy priorities which determine their choices of the energy mix. Major accidents, such as Fukushima, may also play a role in influencing gas demand. In the very long term, climate change may also affect gas demand directly (as opposed to the indirect impact it already has on policies) through changing temperatures ('global warming’) and new weather patterns.

Gas demand is mostly influenced by seasonality (increased demand for heating in winter) and geography/climate (more demand for heating in colder areas). Natural gas demand also varies on an (intra)daily basis, e.g. according to temperature (e.g. more space heating if it is cold), time of the day (more water heating in the morning when people take a shower) as well as the workday/holiday schedule (less industrial demand during public holidays and weekends).

Especially governments of gas-producing countries sometimes provide subsidies to keep the price of natural gas artificially low, stimulating demand. But regulated gas retail prices are still common even in several EU Member States, as outlined in the recent Commission Communication "Making the Internal Energy Market Work" and further discussed in chapter 3. If prices are regulated below supply costs, this may be positive for demand, but negative for investments. A carbon price would increase the competitiveness of gas vis-à-vis coal, but in the long run might favour nuclear or renewables wherever these sources are substitutes. As carbon prices are either non-existent (most parts of the world) or relatively low (the present EU allowance price is some 4 €/tone of CO₂), the impact of this form of government intervention has so far been limited.

**Transportation**

Transportation costs are significant due to the low energy density of natural gas and may, in some cases, exceed exploration and extraction costs. Gas trade is still dominated by pipelines, which account for 68% of total gas trade (IEA 2013). Yet, until 2011 LNG has been gaining significant share, especially over long distances. While pipelines generally remain the most common means of gas trade, LNG is already responsible for 42% of interregional gas trade (IEA 2013). Global LNG trade volumes more than doubled between 2000 and 2010 (JRC 2012), clearly exceeding the increase in gas demand. In 2012, however, the global LNG market declined by 2%. The decline was even more pronounced in Europe (the second-largest LNG market after Asia with 66 bcm imported in 2012), which imported 26% less than in 2011 (IEA 2012b).

**Storage**

Storage is an essential element of the natural gas supply chain for three main reasons:

- **Demand variability:** it would not make economic sense to build enough production and transmission capacity to meet peak demand.
- **Price volatility:** storage can be an attractive instrument to hedge against the commercial risk of very high prices during peak demand and limit the market power of suppliers.
- **Risk of supply disruptions:** as natural gas is often transported over long distances and across national borders, storage provides the possibility to reduce the risk of supply disruptions which may otherwise occur for technical, political or commercial reasons.

In addition, storage facilities are needed to ensure the safe operation of the gas transmission and distribution systems. They may also serve market developments by providing ‘wheeling, parking and loaning’ at major interconnections, for example.
Market organisation

The gas industry can be divided into three parts – upstream, midstream and downstream. Upstream activities refer to natural gas exploration and production. The midstream gas business includes the gathering system, processing, compressor stations, LNG terminals, underground storage facilities, as well as the gas transmission grid, hubs and market points. The downstream oil sector is a term commonly used to refer to the selling and distribution of natural gas to consumers. Midstream activities are often grouped with downstream activities.

Liberalisation has had an impact across all of the gas supply chain. Upstream, regulated wellhead prices were only abolished completely in the United States in 1989 and regulated prices still exist in some parts of Europe (see section 2.3.4). Midstream, third-party access to pipelines and storage makes a difference, allowing for the entry of new market participants. Downstream, unbundling requirements for distribution system operators may create more retail competition.

If there were a global gas market, market concentration on the supply side (upstream) would be very low as gas resources are abundant and large numbers of companies are active in the upstream gas business. Yet, due to high transportation and storage costs, gas markets remain rather regional, and pipelines with high sunk costs and long lead times often bind buyers and sellers to each other. The LNG ‘revolution’ is currently changing the picture (increasing destination and origin flexibility). Regional differences remain significant, though. While the United States has a highly competitive upstream industry including the (super) majors as well as independents, in Europe the upstream industry is more concentrated (with strong historical incumbents complemented by the US majors). In the other parts of the world – which control the largest share of proven gas reserves – the market is commonly in the hands of one or few state-controlled companies.

The demand side (midstream and downstream) suffers from natural monopoly problems (gas networks and storage). Liberalisation efforts (unbundling and deregulation) have created some competition in OECD countries (especially the United States and the United Kingdom as explained in Section 2.1.2), but market concentration is still high in many markets, including several EU Member States. Vertical integration is still dominant in most other parts of the world, where market concentration is thus very high.
ANNEX B: MARKET FUNDAMENTALS OF STEAM COAL

Together with oil and natural gas, coal is a leading primary energy globally, accounting for around 32% of global primary energy consumption (VDKI 2012) and around 40% of global electricity generation (IEO 2013).

Coal is a heterogeneous product with different coal types based on different geological ages, heating values, content in volatile components and generally chemical composition including ashes as well as physical properties, notably size (Brandt 2000). Coal price indices for standardized coal qualities are provided for steam coal\(^{156}\) and coking coal\(^{157}\).

Coal is transported by rail, road and ship, depending on distance and available infrastructure, where in general ship transport is the most economical. Lignite, based on its lower heating value than hard coal, is in general transported over very short distances only, and consumed in dedicated power plants close to the mining area. Therefore, lignite trade is virtually inexistent. Production costs of lignite dominate its price, which is not affected by world energy markets (Panos 2009). Consequently, the following sections will focus on steam coal, where not indicated otherwise.

Coal can be stored easily over long periods of time.

**Coal production and supply worldwide and in the EU-27**

World coal consumption has increased over the past years (see Figure 98). Production reached 7656 million tons in 2011, of which 87% hard coal and 13% lignite (EIA Statistics 2013).

**Figure 98: Total global coal consumption and production**

![Graph showing total global coal consumption and production]

**Source:** Study authors based on (EIA Statistics 2013)

---

\(^{156}\) Used for electricity generation.

\(^{157}\) Used for steel making. Hard coal includes both steam coal and coking coal.
In 2011, the most important producing countries globally representing around 83% of global hard coal production were China (51% of global production), the United States of America (14%), India (8%), Indonesia (6%) and Australia (5%) (see Figure 99). The most important coal producing country in the EU is Poland with 75.6 million tons in 2011 (1.1% of global production) (EIA Statistics 2013).

**Figure 99: Global hard coal production 2011 by producing country**

The largest coal producers are also the largest consumers. Figure 100 shows the development of net imports and net exports\(^{158}\) by countries over the past decade. Most notably, the largest producer and consumer China used to be a net exporter of coal, but has become a net importer between 2006 and 2009. In 2012, Chinese net imports accounted for around 20% of global net imports. No other country relevant for the world market has changed from net exporter to importer, or vice versa, in this timeframe. Other major importers are the EU-27, Japan and India. Main exporters are Australia, Indonesia, the countries of the former Soviet Union (GUS), Colombia, South Africa and North America. It should be noted that total global net imports/exports only account for less than 15% of production/consumption.

According to (EWG 2013), the expansion of Indonesian coal production was very rapid, and has provided the necessary quantities for the growth in net imports, notably in the Asia Pacific region. However, expansion of coal production in Indonesia has reached its limits; coal exports are expected to stagnate over the coming years, and to decline thereafter. The future availability of coal on the global market will be determined by the two largest exporters Indonesia and Australia (EWG 2013). Net exports of the USA have increase over the past years based on a switch from coal to gas in power generation (VDKI 2012). The future development there will also be an important factor on global coal markets.

\(^{158}\) Net imports are imports minus exports in order to show the net balance of each country; ditto for net exports.
Figure 100: Development of hard coal net imports and net exports by country

Source: Study authors based on (EWG 2013), (VDKI 2013)

Coal production and supply in EU-27

Hard coal production in the EU-27 is declining (see Figure 101). In 2011, almost all producing EU Member States recorded declining production. A further decline in production is expected. Poland continues to be the largest producer in the EU-27 (VDKI 2012).

Figure 101: EU hard coal production

Source: Study authors based on Eurostat database 2013, 26.06. 2013

Coal is an important source of energy in the European Union, representing 19% of primary energy supply in 2012 up from 16% in 2011 based on decreasing coal and CO₂ emission prices (VDKI 2013), and a 25% share in electricity generation in 2010. However, there are big differences between European countries: Poland, for example, produced more than 90% of its electricity from coal, while electricity supply in Lithuania and France rely to less than 5% on coal (see Section 2.5 Electricity).
As a general long-term trend, coal consumption in the EU-27 has decreased over the last two decades (see Figure 102). However, since 2009 consumption has been increasing. Largest coal importers in the EU-27 are the UK and Germany, followed by Spain and Italy.

**Figure 102: Hard coal gross inland consumption**

![Graph showing hard coal consumption](image1)

*Source:* Study authors based on (Eurostat 2013h)

The biggest steam coal exporters to Europe currently are the USA, Colombia and Russia together covering 70% of EU imports (see Figure 103). Australia and Indonesia play minor roles for Europe, although they are the largest exporters globally. This structure has changed over the past years. South Africa and the Ukraine who used to be the main sources of coal a few years ago have become less important for the EU; Russia’s importance has declined somewhat. At the same time, US coal imports to Europe have increased significantly over the past years, and coal trade from Colombia to the USA have decreased with the quantities redirected towards Europe (VDKI 2012), (VDKI 2013).

**Figure 103: Hard coal imports into the EU-27 by country of origin, 2012**

![Pie chart showing coal imports](image2)

*Source:* (Eurostat 2013)
Global seaborne coal market

2011 international (seaborne) coal trade accounted for around 1 billion tons (of which 76% steam coal), or 15% of global hard coal production (VDKI 2012). Figure 104 shows the global seaborne hard coal trade flows in 2012. It demonstrates the important Pacific market, and the rather separated Atlantic market with lower quantities (see Figure 105). This separation is mainly based on transport costs. Lower freight rates favour longer transport distances and lead to a more uniform world market (Rietschel et al. 2007).

**Figure 104: Main trade flows in seaborne hard coal trade, 2012**

![Seaborne trade: 978 mn MT Incl. 826 mn Mt steam coal](image)

**Source:** (VDKI 2013)

**Figure 105: Steam coal market 2012**

![Steam Coal Market: Quantities Between Atlantic and Pacific Market](image)

**Source:** Study authors based on (VDKI 2013)
ANNEX C: FUEL COSTS OF INTERNATIONAL MARITIME COAL TRANSPORT

In order to assess the impact of oil price on transport costs, the fuel consumption and fuel costs for coal transport are calculated for a typical bulk carrier using heavy fuel oil (HFO). Colombia and the USA as major origins of imported coal in Europe are used for this assessment.

**Table 12: Fuel consumption of a capesize bulk carrier**

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Deadweight (payload + fuel)</td>
<td>88200</td>
<td>Tons</td>
</tr>
<tr>
<td>Fuel consumption full load</td>
<td>0.0123</td>
<td>kWh HFO / tkm coal</td>
</tr>
<tr>
<td>Fuel consumption empty</td>
<td>0.0102</td>
<td>kWh HFO / tkm coal</td>
</tr>
<tr>
<td>Fuel consumption round trip</td>
<td>0.0225</td>
<td>kWh HFO / tkm coal</td>
</tr>
</tbody>
</table>

*Source:* Specifications of an 88,000 DWT-type coal carrier based on (kline 2013)

The biggest coal terminal in Europe is the Rotterdam port. The biggest east coast US coal terminals (Lambers pont, Piper IX) are in Newport News. The main Atlantic coal port of Colombia is in Cienaga. The ship transport distances are estimated using the calculation tool of (sea 2013). Although ship operators generally try to maximize revenue by transporting cargo on both outward and return journeys most of the coal carriers lack alternative payload for the return trip. Therefore it is assumed here that the total round trip consumption needs to be assigned to the coal transport (see Table 12).

To see the approximate contribution of HFO on the final European coal price, the fuel cost of a typical transportation trip from USA and Colombia was calculated; see Table 13.

**Table 13: Fuel cost of a typical transportation trip from USA and Colombia, 2011**

<table>
<thead>
<tr>
<th>Export terminal</th>
<th>Import terminal</th>
<th>Transport distance (km)</th>
<th>Fuel consumption (kg HFO/t coal)</th>
<th>Fuel price (min) €/t</th>
<th>Fuel price (max) €/t</th>
<th>Fuel cost (min) €/t</th>
<th>Fuel cost (max) €/t</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cienaga Colombia</td>
<td>Rotterdam Netherlands</td>
<td>8293</td>
<td>16.5</td>
<td>394.84</td>
<td>509.37</td>
<td>6.51</td>
<td>8.40</td>
</tr>
<tr>
<td>Newport News USA</td>
<td>Rotterdam Netherlands</td>
<td>6563</td>
<td>13.1</td>
<td>394.84</td>
<td>509.37</td>
<td>5.16</td>
<td>6.65</td>
</tr>
</tbody>
</table>

*Source:* Study authors; HFO price data from (DEstatis 2013)
ANNEX D: METHODOLOGY APPLIED FOR THE SELECTION OF 10 MEMBER STATES

In order to have a balanced selection of 10 Member States serving as examples of regional markets in the EU and describing different situations across the EU, the project team has identified a set of five criteria that guided the selection of the Member States:

1. *Geographical balance*: in order to ensure an adequate coverage of all EU regional sub-markets (Northern Europe, Western Europe, Eastern Europe, Southern Europe, etc.).

2. *Energy prices*: in order to shortlist countries presenting either very high or very low energy prices and/or historically higher than average price volatility. For retail prices, this criterion has been assessed through the analysis of recent data from Eurostat on electricity and gas end-user prices for both domestic and industrial consumers, as well as through the analysis of the Market Observatory for Energy publications for the period 1998-2011.

3. *Regulatory framework*: this criterion serves to identify countries with a particular regulatory framework affecting pricing, taxation, market organisation, etc., which might affect the impact of oil prices on retail and wholesale energy prices. In this regard, the level of market liberalization is also taken into account by this criterion.

4. *Socio-political context*: countries that have experienced socio-economic pressures over the last few years due to high energy prices and where this has led to energy becoming a national issue have been identified through a preliminary analysis of recent European press (in English). Further analysis during the project will shed some light onto the price drivers of such socio-economic pressures.

5. *Data availability*: in the context of this study, data availability is of essence. For retail prices, a preliminary screening (in English language) of national sources has allowed the Project Team to identify and assess the quality of the databases publicly available for each Member State. This was used as an exclusion criterion of countries for which the availability of data would not allow for a fair and complete analysis. For wholesale energy prices, data availability is an issue for certain Member States. In general, less data are available for Eastern European countries than for Western European countries. In this sense, a selection between different Member States in a given regional sub-market is sometimes difficult as either data are available for several Member States, or data are not available for any of them.

The first criterion (“geographical balance”) is applied transversally and is reinforced by taking into account interconnections in the European regional sub-markets by selecting countries with many or very few interconnections (see textbox below).

**Box 7: Textbox: “Regionalisation” of national energy markets**

Given the significant disparities across European Union national energy markets, the EU has promoted the “regionalisation” of national markets as a first step towards the implementation of the Internal Energy Market. In February 2006, the European regulators launched an initiative to create seven regional markets for electricity, and three for gas. The Agency for the Cooperation of Energy Regulators (ACER) established in 2009 has been empowered to monitor and coordinate regulatory activities in the electricity and gas markets in Member States and promote the implementation and well-functioning of the IEM. ACER has stimulated further cooperation among stakeholders of all Regional Initiatives (RIs) through a new project-oriented program, whereby each RI should implement a dedicated work-plan for the period 2011-2014 based on specific objectives and milestones.
Complementing the “geographical balance” criterion presented in the previous section, at least one country is selected for each regional energy sub-market (see Figure 106 below). The number of interconnections of individual Member States within the different RIs is also a factor of influence taken into account for example in the cases of France and Germany, which have a large number of neighbouring countries and interconnections; or in the case of Lithuania, which has very few connections.

The map below presents the 10 selected Member States (highlighted in blue in the map) with respect to the seven regional electricity markets in Europe:

- Northern: Finland
- Baltic: Lithuania
- Central-East: Bulgaria, Hungary, Poland
- Central-South: Italy
- Central-West: France, Germany
- South-West: Spain
- France-UK-Ireland: (France), UK

Figure 106: Map of 10 Selected Member States (in blue in the map)

Source: Study authors
ANNEX E: INDIVIDUAL MEMBER STATES ENERGY PRICE COMPONENTS

The Annex introduces the reader to the current state of the art for the selected Member States, presenting a brief analysis of the energy mix, regulatory framework and detailed price decomposition. Depending on data availability similar consumer categories have been used for households and industrial consumers.\(^{159}\)

**Bulgaria**

The Bulgarian energy sector is heavily regulated and dominated by the public utility Bulgarian Energy Holding (BEH). BEH controls all major power suppliers of the country, including the National Electricity Company (NEK). Electricity tariffs for domestic consumers are regulated and computed on the basis of specific pricing formula. An interesting feature of the Bulgarian electricity market is that there appears to be no major distinction between retail and wholesale markets (Spassov, 2012). Wholesale electricity trading is either done by NEK through the regulated market or by long-term bilateral contracts. There is currently no power-exchange system established in the country.

Here below we present the decomposition of electricity prices for an average consumer in domestic consumer in Bulgaria (Band DC)\(^{160}\) and a medium to large size industrial consumer (Band IC), for which regulated tariffs do apply\(^{161}\).

**Figure 107: Evolution of decomposition of electricity prices for domestic consumers in Bulgaria (Band DC) and industrial consumer (Band IC)\(^{162}\)**

![Graphs showing decomposition of electricity prices](image)

*Source: (Eurostat 2013)*

---

\(^{159}\) For retail electricity prices household consumption ranges in between 2.5 and 4 MWh, industry band in between 500 and 2000 MWh. For retail gas prices, average households consumption ranges in between 5MWh and 55MWh.

\(^{160}\) For this analysis only Eurostat data are available. Consumption categories considered are the same as those used by the European Commission for its reports.

\(^{161}\) Eurostat data categorize consumers by predefined annual consumption bands. Here we have selected medium size consumers for both domestic (Band DC: 2 500 kWh < Consumption < 5 000 kWh) and industry (Band IC: 500 MWh < Consumption < 2 000 MWh) end-users. These categories are the same used by the European Commission for its benchmarking reports.

\(^{162}\) The data does not take into account the government announced a 14% increase in July 2012 (Peszko, 2013).
The following observations can be made:

- Wholesale energy costs represent 80% of the final retail price for industrial consumers. For domestic consumers, they represent roughly 50% of the overall cost.
- Taxation represented 17% of total costs for domestic consumers in 2012 and less than 1% for industrial consumers. Both components have remained relatively stable in the course of the time period 2008-2012.
- Network tariffs represented 34% of total price for domestic households and 20% for industry in 2012.
- For both types of consumers the largest increase is noticeable in between 2011-2012 (9% for domestic and 16% for industry).

Solid fuels, such as lignite and brown coal are the dominant energy sources for electricity generation (48%) alongside with nuclear, which accounted for 32.7% of the Bulgarian energy mix (EC 2012). Electricity prices are therefore indirectly influenced by oil prices through the relationship between coal and oil (see chapter 2, sections 2.4 and 2.5). If we refer to chapter 3, sections 3.1.3 and 3.1.4, we see how in PPS electricity tariffs for both domestic and industrial consumers increase disproportionally. This implies that in Bulgaria energy consumers spend a larger proportion of their income in electricity bills in comparison with other EU Member States. Higher electricity prices also have a negative impact on industrial competitiveness of Bulgarian energy intensive industries. In order to keep prices at an acceptable level the government regulated electricity tariffs.

The Bulgarian gas market is relatively small and completely dependent upon Russian imports. The state owned company, Bulgartransgaz EAD is the sole importer and supplier to the local distributors. Data available from the national regulator provide the decomposition between the energy component including network tariffs and taxation including VAT. The following partial conclusions can be made:

- The wholesale energy costs including network tariffs represents roughly 83% of the final price for both types of consumers,
- VAT represents 16.6% of the final price for domestic consumers and 17% for industry; these values have remained stable across the time period 2008-2013.

**Figure 108: Evolution of decomposition of retail gas prices for domestic consumers in Bulgaria (Band D2) industrial consumer (Band I3)**

[Graph showing the evolution of decomposition of retail gas prices for domestic and industrial consumers in Bulgaria]

**Source:** Eurostat (2013)

---

163 Eurostat data categorize consumers by predefined annual consumption bands. Here we have selected medium size consumers for both domestic (D2 (Medium): annual consumption between 20 and 200 GJ) and medium-size industry (I3: annual consumption between 10,000 and 100,000 GJ) end-users.
**Finland**

The Finnish retail electricity market is fully liberalised and the wholesale electricity market is perfectly integrated in the market of the Nord Pool, through which 76% of all electricity consumed in the country is traded (EC 2012). According to the Finnish Energy Market Authority (EMV), there are currently 74 retail suppliers to serve 3.1 million customers and tariffs are un-regulated for all type of consumers (EMV 2012). Since 2005 Scandinavian energy regulators have also actively promoted the operation of a unique end-user electricity market for the Nordic area.

Electricity prices in Finland comprise two main cost components: distribution costs and the wholesale electricity price (or “electric energy”). The proportion of wholesale electricity price in the final bill accounts for typically 40-50% of the invoice amount (EMV 2013). Electricity companies are required to set their tariffs following EMV framework, which monitor them ex-post and ensures compliance with existing legislation if necessary (EMV 2013). Tariffs are separated for electrical energy and network services. Network tariffs are dependent upon quantity of electrical energy supplied to the customer, the power demand, and the voltage level at which the customer has been connected to the network (EMV 2013). Electrical tariffs are composed of energy rates, standing charge and demand charge, along with basic energy rates. Based on Figure 109, which shows the evolution of domestic consumer prices (Band L1164), we can observe that in August 2012 (latest data available at the time of writing) roughly 44% of the electricity was related to provision costs (“electricity costs”), 45% to distribution services and related taxation and roughly 10% to VAT.

**Figure 109: Development of the price of electricity by individual component for Finland**

According to the information provided by the national energy regulator, taxation rates are purely based upon levels of consumption: industrial customers pay 0.44 cent/kWh while others pay a higher rate of 0.73 cent/kWh. The electricity component is also subject to a VAT rate of 22% (EMV 2013).

---

164 Single house with direct electric heating, fuse 3x25 A, consumption 18 000 kWh/year
Concerning the evolution of the price for retail consumers, an overall increase of 2.7% occurred in between 2010 and 2011, with VAT increasing by 2% and network charges by 4.5% (EMV 2013).

Detailed decomposition of retail electricity prices is not available for industrial and business users through the energy regulator. According to Eurostat, in the year 2012 66% of energy bills was composed of wholesale energy costs, 25% of network costs and 9% of taxes.

The Finnish energy mix is strongly centred on the production of heat from wood fuel source (25% of total energy consumption). Renewable energy is the dominant source for the production of electricity (30%), followed by nuclear energy (28%) and solid fuels (26%). Retail electricity prices in PPS are amongst the lowest in Europe, probably thanks to the combination of nuclear electricity and high level of competitiveness in the retail market, which has kept prices low.

In comparison with electricity market, the national gas market is very small (2% of total energy consumed). It is physically connected to only one non-EU supplier: Russia. For this reason Finland has requested and obtained an exemption from fully transposing the Natural Gas Market Directive.

**France**

France is the largest producer of nuclear energy in the EU. Nuclear energy makes up for the largest portion of energy consumed, followed by oil and natural gas (CRE 2013a). While all nuclear electricity is produced nationally, France is dependent upon foreign imports for oil and natural gas (as well as uranium, of course). The French government has taken in recent years important steps toward the liberalisation of energy markets, however, both the electricity and gas retail markets remain highly concentrated, with Electricité de France (EDF) and GDFSuez dominating most production and supply (EC 2012).

For what concerns electricity, end-users have the choice to request either free-market tariffs or regulated tariffs that are available only from EDF. The tariffs proposed are the following:

- **Blue tariff**: Domestic consumers (consumption capacity < 36 kWh)
- **Yellow tariff**: Medium size consumers (SMEs) 36 kWh ≤ consumption capacity ≤ 250 kWh
- **Green tariff**: Large consumers (consumption capacity > 25 kWh)

Figure 110 shows the evolution of the different consumer tariffs (excluding taxation), which notwithstanding average increase in production costs, have decreased constantly in between 1996 and 2008.

According to the Commission de régulation de l’énergie (CRE):

- Since 2008 the blue tariff increased on average by 2% per year,
- Yellow tariff increased on average by 4% per year,
- The green tariff has increased by an average of 5% annually.

---

165 Consumer Band IC: 500 MWh < Consumption < 2,000 MWh
Figure 110: Evolution of French tariffs (taxes excluded) for different consumer categories in euros at constant prices for the period 1996-2012

Figure 111 below presents the price decomposition of each individual tariff for the current year (CRE 2013a). The following trends are easily identifiable:

- Wholesale energy costs are responsible for 40 to 60% of total energy bill, while network tariffs take on average 30%, with discrepancies between different type of consumers,
- Wholesale energy costs are less relevant for domestic consumers (37.4% of the total price) in comparison with industrial consumers (39.4% for yellow tariff and 58.4% for green tariffs),
- For domestic consumers taxation accounts for 32% of the tariff, while for SMEs this percentage is only 19% and for large industrial consumers 23%.
Figure 111: Electricity price decomposition for the French retail market by type of consumer, situation on March 31st 2013

Source: CRE (2013a)

The following tax and charges were identified as part of the tax component:

- The “Contribution Tarifaire d’acheminement (CTA)”, contributing to the financing of the pension system of industry personnel,
- Local and regional taxes set independently by each municipality,
- The “Contribution au service public de l’électricité (CSPE)” which includes a variety of sub-charges for the financing of electricity services, renewable energy support etc.
- VAT at 19.6% rate (taken into account for domestic consumers only).

As an alternative, suppliers are also offering consumers the possibility to have free-market based tariffs. Network tariffs and other taxes are also charged on free-market tariffs, while supply costs and are dependent upon the energy suppliers and consumer category. In principle market-based tariffs should follow closely French electricity spot prices. However, in reality free market tariffs, are pegged to the regulated tariffs, which ends up having a stronger influence on the tariff level than spot prices.

Recent price increases from non-nuclear based suppliers have led many consumers to go back to the artificially low regulated tariffs.

166 Blue tariff (household) Band Dc: consumption in between 2500 and 5000 KWh. Yellow tariff (business and industry): band Ib: consumption in between 20-500 MWh. Green tariffs (businesses and industry): Band Ie: consumption in between 20 000 and 70 000 MWh.
The gas market is also characterised by high concentration and regulated tariffs. The majority of imports (80% of total consumption) come from Algeria, Russia and Norway. Non-regulated tariffs are available, yet the 86% of domestic customers remain loyal to the regulated gas tariffs provided by GDF Suez. GDF Suez tariffs are set on a monthly basis through a pricing formula that takes into account oil price indexation deriving from long-term contracts, spot market rates and fluctuations in foreign-exchange levels. Therefore the energy component in the tariff is historically heavily dependent upon oil prices. This relation seems to have slightly decreased in recent years since GDF Suez has been renegotiating its long-terms contract with suppliers (Platts 2013).

Figure 112 below provides the price decomposition of the regulated tariff offered by GDF Suez during the first trimester of 2013. The following observation can be made:

- Primary energy cost represents the main component of the final energy bill (55%),
- Transmission, distribution and storage costs represent roughly 30% of total cost and two taxes are applied (the CTA which represents electricity access charges)
- VAT accounts for 15%. Local consumption tariffs are also applied and may vary depending on the level of consumption.

**Figure 112: Price decomposition of the regulated tariff offered by GDF Suez year 2012**

![Regulated tariff components GDF Suez](image)

**Source:** CRE (2013a)

Tariff regulation and the high share of nuclear electricity have contributed to keep retail electricity prices low in France. Due to the dependence on foreign imports and oil indexed contracts, gas retail prices are more vulnerable to oil price changes. However the company GDF Suez has recently renegotiated its long-term contact with its main suppliers from Norway and Russia, to reduce the volume of oil indexed contracts and reduce the impact of oil price on retail gas prices.

---

167 Average consumer consumption band not defined.
Germany

Germany is the largest consumer market within the EU-27, representing almost 19% of total primary energy, followed by France (16%), the United Kingdom (12%) and Italy (10%) (Eurostat 2010). In 2011, lignite was the most common source for the production of electricity (22%). Renewable energies came second supplying some 20% of gross power consumption in 2012.

Figure 113 shows the comparison among price indexes for retail electricity and gas for end-users with respect to the evolution of oil prices (€/hectolitre (hl)). Aside from the noticeable increase in both electricity and gas prices during the last decade, it is also visible that gas prices tend to follow much more closely oil prices than electricity prices. This might be due to the impact of existing long-term contracts between supplier and exporters pegged to the price of oil. Clearly, the evolution of domestic electricity prices is by far the most stable in comparison with other indexes. This is probably due to the fact that electricity is mostly produced by solid fuels such as lignite (47%) of which the country is a producer.

**Figure 113: Germany evolution of gas and electricity price index in comparison with oil prices for the period 2000-2012**

![Graph showing the comparison of gas and electricity price index with oil prices for the period 2000-2012.](image)

**Source:** (Destatis 2013)

The retail electricity market has been fully liberalised since 1998 and the wholesale market enjoys a very good degree of integration with neighbouring countries, in particular with the Austrian market. According to EC (2012), for the year 2010 roughly 47% of electricity consumed in Germany was traded on the EPEX spot market.

The retail domestic electricity price decomposition presented in Figure 114 is based on volume-weighted average across all tariff categories (Bundesnetzagentur 2013). The following observations can be made:
Actual wholesale energy costs (here indicated as “energy” procurement) is responsible for only 24% of the final electricity price, supply including “margin” accounts for 8% of the final price,

Network tariffs represents 21% of the retail price,

Different taxes and sub-charges, both national and local, are added up making up 45% of the final price.

According to BDEW (2013), electricity prices for domestic consumers have increased by 68% between 1998 and 2013. Among the individual components, taxes have tripled their share, while production and network charges have increased by 11%. General taxes and levies include the following sub-charges (Bundesnetzagentur 2013):

- VAT at 19%, accounting for 16% of the final price (36% of the tax component),
- A local licence fee, accounting for 6% of the final price and 14% of the tax component,
- The “Erneuerbare-Energien-Gesetz” EEG surcharge, which supports Renewable Energies, accounts for 14% of the final price (31% of the total tax component),
- The “electricity tax”, accounting for 8% of the final price (18% of the tax component),
- A small charge established under section 19 StromNEV making up 0.6% of the final price.

**Figure 114: Electricity retail price composition domestic consumers for Germany on April 1 2012**

<table>
<thead>
<tr>
<th>Component</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net network tariff</td>
<td>21%</td>
</tr>
<tr>
<td>Charge for the billing</td>
<td>6%</td>
</tr>
<tr>
<td>Charge for the metering operation</td>
<td>14%</td>
</tr>
<tr>
<td>Energy procurement</td>
<td>24%</td>
</tr>
<tr>
<td>Supply (incl, Margin)</td>
<td>8%</td>
</tr>
<tr>
<td>Concession fees</td>
<td>1%</td>
</tr>
<tr>
<td>Contribution under EEG</td>
<td>1%</td>
</tr>
<tr>
<td>Contribution under section 19 StromNEV</td>
<td>1%</td>
</tr>
<tr>
<td>Electricity tax</td>
<td>8%</td>
</tr>
<tr>
<td>VAT</td>
<td>16%</td>
</tr>
</tbody>
</table>

**Source:** (Bundesnetzagentur 2013)

Figure 115 provides instead the detailed composition of electricity bills for industrial customers in 2012 with an average annual consumption of 24 GWh. Similarly to other countries, the percentage share of retail prices related to wholesale energy costs and network tariffs are higher for industrial consumers than for domestic ones. In the German case, however, the difference is less marked given that the taxation component represents an important component of electricity bills also for industrial consumers.
It has to be considered that of the component “Taxes (electricity and VAT)”, accounting for 29% of the final price, 16% is VAT (19% VAT rate) recoverable for business activities.

**Figure 115: Electricity retail price composition for industrial customers for Germany on 1 April 2012**

Source: (Bundesnetzagentur 2013)

Germany is the second largest gas consumer in Europe. 89% of gas consumed in Germany comes from imports from Russia, Norway and the Netherlands. Most of the long-term supply contracts are linked to the price of oil (see chapter 2), but for domestic consumers there is no direct link. Households can be supplied with natural gas through three different types of contracts (Bundesnetzagentur 2013):

- At the default supply tariffs;
- With the same supplier but outside of the default supply structure\(^{168}\) signing a special contract, this option is known as ‘supply under change of contract’;
- Outside the default supply network\(^{169}\) and with a new supplier under special terms conditions, this option is known as ‘supply at switch of supplier rates’.

The detailed decomposition of domestic gas prices at default supply service is shown in Figure 116:

- Energy procurement and supply entails roughly 54% of the final gas price, network tariffs 17%,
- The remaining cost includes VAT (16%), gas tax (8%) and metering billing cost (5%).

---

\(^{168}\) “With this supply option, the household customer stays with his current supplier, but signs a new supply contract under special terms” (Bundesnetzagentur 2013). The supply of gas is within the same network area, but under different contractual conditions from default supply.

\(^{169}\) “Supply outside of the default supply network area means that the household customer signs a supply contract with a new supplier according to special terms” (Bundesnetzagentur 2013). The supply under this option is within a different network area and with different conditions from those applied to the default supply.
When comparing gas price decomposition of the different tariffs there seem to be no major discrepancies among the various options.

According to the recently published report by the Federal Network Agency household customers receiving supply under change of contract have seen a larger increase (8%) in their gas bill than customers under the default supply system (5%) (Bundesnetzagentur 2013). Business and industrial customers are offered only tariffs at supply under change of contract and supply at switch of supplier.

**Figure 116: Retail gas price composition for households at default supply service – April 2012**

Source: (Bundesnetzagentur 2013)

The detailed decomposition of gas prices for industrial customers with change of supplier tariff is presented below. Energy procurement and supply make up over 67% of the final gas price. According to national report this component has increased by 15% within one year while the overall gas price increased by 7% under this supply category. As in the previous example, there seems to be no major discrepancies when comparing prices decomposition of different supply categories for business and industry consumers. The one presented below is provided as an example. Considering that VAT is deductible for business activities, the final price decomposition changes, with 77% of the final price accounting for energy and supply costs, 8% for network costs and 14% for the gas tax.
Regulated components such as network tariffs and surcharges have progressively contributed to the recent increase in retail electricity prices. With respect to the evolution of retail gas prices, there is a distinct upward trend of the energy procurement component for all supply categories, most likely due to the perpetual increase in the import price of natural gas (Bundesnetzagentur 2013). When comparing different supply, the largest increase is found to be for consumers supplied according to change of supplier tariffs (Bundesnetzagentur, 2013).

Hungary

Natural gas accounts for the largest share in the Hungarian energy mix, with 38% of primary energy consumption. This is followed by oil with 25% (IEA 2012c). Given the low quality and scarcity of local resources, Hungary imports roughly 70% of its gas from Russia. For this reason, diversification of gas energy imports is an important element of the Hungarian energy policy. Electricity on the other hand is mostly produced from nuclear power (42%) and gas (31%), along with coal and a small portion of renewable energy and waste-to-energy (IEA 2012b).

Figure 118 shows the evolution of gas prices changes throughout the year 2011, where we can see that the wholesale gas price clearly follows the oil price. This is due to the historical pricing formula in use, whereby 60% of the natural gas price was derived from long-term oil based index contracts and 40% from spot market prices. In order to hinder the impact of oil price the ratio was inversed starting from the end of 2011 (MEH 2012). In comparison to wholesale prices, end user gas price remains stable and low throughout the year, mostly due to frozen overhead costs and artificially low power procurement prices in place due to regulation (MEH 2012).
Concerning retail electricity prices, small businesses and households are entitled to benefit from a “universal tariff” for electricity, while large industrial consumers have access to deregulated tariffs since 2004. In its latest monitoring report on recent activities, the national energy regulator notes that transition from regulated tariff to free market has proceeded at a good pace, with free market tariffs increasing steadily from 33% in 2005, to 63% in 2011 (MEH 2012).

As we can see from Figure 119 below:

- The largest component of domestic electricity price is the wholesale price, which represents 39% of the total final cost;
- Supplier margin accounts for 3.79% of the final price;
- Distribution charges represent 29% of final prices
- The remaining is made of VAT (20%) and other charges (in between 5/10%).

Source: (MEH 2012)
Figure 119: Hungarian electricity prices by components concerning a model household consumer (2400 kWh/year consumption in general tariff)

The evolution of retail electricity prices for a “model” consumer (MEH 2013). The total end-user price has doubled in the period analysed; VAT in particular increased from 12% to 27%. Due to recent government intervention, a decrease in all components took place between 2012 and 2013. It was not possible to retrieve the detailed decomposition of retail electricity for industrial consumers. Based on Eurostat data, in the year 2012 63% of retail electricity prices bills was related to wholesale energy costs, 31% to network costs and 6% to taxes.
For what concerns the gas tariff system, large industrial consumers purchase natural gas at liberalised market tariffs, while small users (households and SMEs) are offered a “universal tariff” (regulated price). Notwithstanding, with the removal of subsidies and opening of the market, the supply and network tariff component has tripled its value since 2001. The final household gas price including VAT is four times higher than what it was a decade ago.

Changes in the market structure and the impact of partial market liberalisation are particularly noticeable in Figure 121 below, which shows the evolution of gas tariffs since 2001. Starting from the year 2006 we can see how the price increases at a much faster pace than before, due to the lack of regulated prices. No disaggregated data was made available on energy procurement and supply costs by the national regulator, but it is estimated that wholesale average price and network tariffs account for roughly 78% of the final gas price (MEH 2013). VAT accounts for roughly 22% of the total price.

Source: (MEH 2013)
**Figure 121: Evolution of the average natural gas price for households (HUF/m3) in Hungary**

![Graph showing the evolution of natural gas prices for households in Hungary](image)

**Source:** (MEH 2013)

**Italy**

Italy has some of the highest electricity and gas prices in Europe mainly due to the high reliance on imported oil and gas and the high cost of general duties paid in the bill (Eurostat, 2013). In 2010 oil was the primary energy source (36%, including transport use), closely followed by gas (35%). Natural gas is also the main source from which electricity is produced (52%) and due to scarcity of natural resources, Italy imports 90% of its inland consumption (EC 2012).

The reader can refer to Figure 122 detailing electricity price main components for domestic users:

- Production and supply costs, which include wholesale energy costs and retail costs for the production and supply of electricity, cover 54% of the final electricity price.
- Network tariffs account for 14% and general system tariffs for 18%. Taxes including VAT cover 13% of the final bill.
- For industrial and business consumers since January 1, 2012 electricity prices are partially pegged to wholesale prices and are now offered tariffs revised each month and for each time slot.
Network charges include distribution and transmission charges, set by the national energy regulator, may vary at the local and regional level. Along with transmission and distribution charges, another important component is made of various aggregated sub-charges, known as “general system tariffs” (AEEG 2013a). These are set yearly by the regulator; the largest share charged for the promotion of renewable energy and energy efficiency. General system tariffs also take into account inflation, investments made and foreseen for energy efficiency improvements (AEEG 2013a). The component “taxes” include (AEEG 2013a):

- National consumption taxes, applied regardless of the level of consumption,
- VAT, currently equivalent to 21% and applicable to the overall value of the bill,
- Local and regional taxation may also apply and the level of network charges may vary among regions.

Detailed decomposition of retail electricity price for industrial consumers was not available through the energy regulator. Based on Eurostat data, in the year 2012 53% of retail electricity prices bills was related to wholesale energy costs, 19% to network costs and 27% to taxes and charges.

Similarly to the electricity prices, the main price components of natural gas are fuel costs, network charges and taxes. Please refer to Figure 123 below providing detailed breakdown of gas prices for average household consumer:

- Fuel costs account for 39% of the final price,
- Retail and dispatching costs account for 8%
- Network charges, including the cost of storage, transport and distribution cover 18% of the final price.
- The remaining 34% of price is made of different taxes and levies.

**Figure 122: Italian percentage composition of the electricity price for a household consumer – 1st quarter 2013**
Figure 123: Detailed breakdown of gas prices for average household consumer – Italy

![Diagram showing gas price components for household 2013](image)

Source: (AEEG 2013)

Italian electricity production costs are particularly high due to its national energy mix. System charges and regional surcharges have also an important impact through the component ‘general system tariffs’. Concerning retail gas prices, the energy regulator launched a reform of the gas market and announced the intention to link retail gas prices to spot market starting October 2013 (AEEG, 2013). This approach is meant to reduce the indirect impact of long-term contracts linked to the price of oil in the future.

**Lithuania**

Lithuania must rely on Russian exports for roughly 80% of its energy since the closure of its main nuclear power plant “Ignalina” in 2009. Imports include both gas from Russian giant Gazprom and electricity, still from Russia. Along with the other Baltic states, Lithuania is often referred to as an *energy island*, in the sense that little or no physical connections exists with other EU Member States, while the electricity and gas systems are satellites of the Russian one. The main problem faced by the energy sector therefore relates to the high level of dependence on foreign imports due to the lack of local capacity and of diversified supply sources.

For what concerns electricity retail prices, domestic consumers are offered regulated tariffs. The pricing mechanism is established by the National Control Commission for prices and energy (NCC), which also establishes a price ceiling, network and system tariffs. The NCC is also required to monitor against discrimination and unfair behaviours toward end-users. Figure 124 below provides the country electricity price structure for household consumers.
Figure 124: Lithuanian electricity retail price structure

![Lithuanian electricity retail price structure](image)

**Source:** (NCC 2013)

From Figure 124 the following observation can be made:

- Wholesale energy costs (here “purchase price”) accounts for 40% of the final price;
- Network tariffs, including charges on low, medium and high distribution account for 34% of the final bill.
- Other taxes, such as public service obligation and price ceiling accounts for 26% of the final price.

Figure 125 shows the evolution of retail electricity prices for the period 2002-2010. Clearly prices have had a tendency to rise, on average 5.1% in the period analysed (Bobinaite & Juozapaviciene 2012). In 2010, the share of electricity production price increased to 46% of total price (from 28% the previous year). This change is due to the shutting down of the Ignalina Nuclear power plants and the increase in electricity imports from Russia.
Industrial consumers and SMEs are furnished through the free-market independent suppliers and detailed data on price decomposition is not available through the national regulator. Based on Eurostat data, in the year 2012 43% of retail electricity prices bills was related to wholesale energy costs, 56% to network costs and only 4% to taxes and charges.

Concentration of power is high in both wholesale and retail gas markets, where Lietuvos Dujos, AB and Dujotekana, UAB dominate almost entirely the production and supply chain. Most of the gas imported is used for electricity production and co-generation services, while the household share of gas consumers was only 9.8% of the total. Connection fees for domestic consumers are partly fixed and partly based on length of the connection through the pipeline.

To summarize the Lithuanian example, retail electricity price have recently increased due to important changes that have taken place in the energy mix. Due to a weak interdependence between electricity and gas prices little impact from oil price onto electricity prices can be found. Due to strong dependency upon foreign imports also of electricity, it is often the case that the marginal price in the wholesale electricity market is set by imported electricity rather than production costs. On the other hand, oil prices have a direct impact on gas wholesale prices, through long-term indexed contracts. This will probably change in the near future, since in line with EU provisions, the country is expected to restructure its energy sector, including attempts to renegotiate its long-term contracts with Russian supplier Gazprom.

Source: (Bobinaite & Juozapaviciene 2012)
Poland

Poland’s energy mix is dominated by oil, gas and hard coal, from which almost all electricity is produced. While the country performs quite well in terms of security of supply, it has one of the worst records in terms of energy intensity of the economy, reason being its strong reliance on solid fuels for heat and electricity production (EC 2013).

**Figure 126: Evolution and forecast of energy mix for Poland**

![Evolution and forecast of energy mix for Poland](image1)

*Source: (IEA 2011)*

The electricity market is characterised by high concentration and is dominated by a small number of suppliers, in particular AURON Polska Energia, PGE Dystrybucja and ENERGA Operator (EC 2012). Household consumers are offered regulated tariffs, while electricity prices for industry consumers are established according to market-based rules. Large industrial consumers are able to negotiate individual contracts based on consumption levels and consumer profile.

In Figure 127 below we present the decomposition of electricity prices for an average consumer in domestic consumer in Poland (Band DC) and a medium to large size industrial consumer.

**Figure 127: Evolution of decomposition of electricity prices for domestic consumers in Poland (Band DC) and industrial consumers (Band IC)**

![Evolution of decomposition of electricity prices for domestic consumers in Poland (Band DC) and industrial consumers (Band IC)](image2)

*Source: (Eurostat 2013)*
The following observations can be made:

- During the second half of 2012\(^{170}\), wholesale energy costs represented 41% of the final retail price for domestic consumers and 60% for industrial ones.

- In the same period, taxation represented 22% of the total price for domestic consumers and only 5% for industrial consumers. Both components have remained relatively stable during the course of the time period 2008-2012.

- Network tariffs represented 37% of total price for domestic households and 30% for industry.

- Electricity retail prices are relatively stable, industry prices inclusive of taxation and network tariffs are roughly a half of domestic prices.

The main source of energy for the production of electricity is coal (86%), of which Poland is a large producer. This has probably contributed to keep retail electricity prices stable and low (see chapter 3, section 3.1 on PPS comparison), notwithstanding the low level of competition within the sector. However, at PPP electricity prices for domestic consumers remain amongst the highest across the EU and are expected to increase further with the increase in cost of CO\(_2\) emissions.

In a similar manner the gas market is dominated by the PGNiG capital group, the main trading partner of natural gas in the country also in control of 6 local distributors. The strong concentration on the wholesale side obviously affects the retail market and changes in the pricing still have to take place. Most customers, especially households, are still offered fully regulated tariffs. The final price includes the energy and subscription rates related to billing, network tariffs and the cost of storage and distribution services. Data on gas prices are presented in section 3.1.

**Spain**

In 2010 within the overall energy mix oil and petrol products accounted for 46% of total energy consumption, followed by gas (23.6%) and nuclear (12.2%). The electricity mix in Spain is more balanced, with similar shares of renewables (33%), natural gas (32.2%) and nuclear (20.5%).

Like most EU Member States, retail markets for electricity and natural gas in Spain have gone through substantial changes since the implementation of the second and third energy package. However, in Spain more than in other countries, the discrepancies between artificially low regulated tariffs and free-market tariffs has been more apparent leading to a large "tariff deficit", that was recognized as the biggest problem for the electricity sector by the national energy regulator.

Both the gas and electricity markets are fully liberalised and consumers have the possibility to freely choose the energy supplier offering the most convenient price. Household gas consumers with annual consumption of gas not exceeding 50,000 kWh and electricity consumers with contracted power not higher than 10 kW are offered regulated price, known as the "Tariff of last resort" (TUR). According to the Comision Nacional de Energia (CNE) in March 2012 26% of electricity consumers and 64% of gas consumers even if entitled to TUR were being supplied under free-market conditions.

Electricity tariffs are composed of a ‘free market component’, related to the wholesale prices and a regulated component, which include network tariffs and other taxes.

\(^{170}\) Latest data available.
Average electricity price (excluding VAT but including the access fee) was 172.11 €/MWh for domestic consumers, 134.94 €/MWh for SMEs and 89.03 €/MWh for large industrial consumers. Comparing these values with those reported in the same period of the previous year, it appears that the final average price for the domestic segment has increased more in percentage level than for SMEs and industrial consumers (CNE 2013). For domestic consumers the final average price rose by 10%, 6.3% for SMEs and only 4.3% for large industrial consumers.

Figure 128 below presents an estimated breakdown of cost components by CNE along with the estimated gross margin by consumer category.

**Figure 128: Estimated average value of each price component for retail electricity prices – Spain**

![Graph showing estimated average value of each price component for retail electricity prices – Spain](image)

**Source:** (CNE 2013)

The energy regulator was only able to provide the figure presented above. On the basis of Eurostat data, the following observation can be made:

- During the second half of 2012, wholesale energy costs represent 36% of the final retail price for domestic consumers and 62% for industrial ones.
- In the same period, taxation (including VAT) accounted for 21% of the total price for domestic consumers in 2012 and only 4% for industrial consumers.
- Network tariffs represented 42% of total price for domestic households and 33% for industry.
- Industry prices inclusive of taxation and network tariffs are roughly a half of domestic prices.
Figure 129: Evolution of decomposition of electricity prices for domestic consumers in Spain (Band DC) and industrial consumers (Band IC)

Source: (Eurostat 2013)

The TUR for gas is updated quarterly and is composed of a fixed component and a variable one that relates to wholesale costs. Table 14 below presents the value for both the fixed and variable components for the two consumer categories (households and medium size industry). As we can see, the fixed component is smaller for smaller consumption and the opposite is true for the variable component.

Table 14: TUR in effect, data from August 2013

<table>
<thead>
<tr>
<th>Consumption level</th>
<th>Fixed component / Euro per month</th>
<th>Variable component</th>
</tr>
</thead>
<tbody>
<tr>
<td>T1 Consumption below or equal to 5000 kWh/y</td>
<td>4.3</td>
<td>5,750871</td>
</tr>
<tr>
<td>T2 Consumption above 5000 kWh/y and below 50,000 kWh/y</td>
<td>8.58</td>
<td>5,078971</td>
</tr>
</tbody>
</table>

Source: IDAE 2013

Figure 130 and Figure 131 below show the evolution of the fixed and variable price component for natural gas in Spain between 2002 and 2011 (CNE 2012). Only one noticeable increase is evident for the fix component while the variable component has gone through a more sustained increase over the course of the last decade. Over the total period time the fixed component increased only by 5.6% while the variable component increased by 17.8%.
Figure 130: Evolution of the fixed component of retail gas prices – Spain 2002-2011

Evolution of the fixed component of natural gas tariff

Source: (CNE 2012)

Figure 131: Evolution of the variable component of retail gas prices – Spain 2002-2011

Evolution of the variable component of natural gas tariff

Source: (CNE 2012)
In conclusion, the Spanish energy markets have gone through important changes, both due to the liberalisation of the electricity and gas markets and strong support to the production of renewable energy. However, the persistence of the cheaper TUR, for both gas and electricity, has undermined the spreading of free-market price offers and led to an important tariff deficit that is having an impact on public finances.

**United Kingdom**

The UK is the largest gas market in the EU, with gas accounting for 35% of primary energy consumption. However, the UK has recently seen national gas production decline while imports have increased from Norway and United Arab Emirates (EC 2012). Renewable energies are also expected to play a major role in future years and due to recent energy policies have come to cover 12% of primary energy consumption.

Both electricity and gas retail markets are fully liberalised; six main suppliers hold 99% of the total market share. Consumers have the possibility to choose among an increasing range of tariffs, including variable tariffs pegged to the wholesale price, fixed and capped tariffs.

Figure 132 below shows the evolution of electricity and gas indexes for both domestic and industrial consumers. According to the data, electricity prices for domestic consumers, including VAT, rose by 1.7 per cent in real terms between the end of 2011 and 2012. Gas prices, including VAT, increased by 6.4 per cent in real terms. For the industrial sector, average industrial electricity prices including the Climate Change Levy (CCL), rose in real terms by 5.2% (real terms) between 2011 and 2012.

**Figure 132: Comparison of fuel price indexes for different consumer categories – UK**

![Fuel price indices in the domestic and industry sector in real terms](image)

**Source:** (DECC 2013a)

According to (DECC 2013), the main components of electricity and gas bills for UK consumers are wholesale energy costs, network costs, supplier operating costs and margins, and the costs of energy and climate change policies.
The report estimates that wholesale energy costs have contributed to 60% of the increase in household bills in the current period. Network costs contributed to 25% of the recent price increase.

The average electricity bill is estimated to be £531 per year (OFGEM 2013). Figure 133 below shows the detailed breakdown of electricity retail prices for households:

- Wholesale energy price and the cost of fuel for electricity make up the biggest percentage of the final price (37%), other supplier costs and margins 21%, network charges represent 23%;
- VAT accounts for 5% of the final price and energy and charges related to climate change policies are estimated to account for 14%;

According to (DECC 2012), the average price paid by households increased by 9% between 2010 and 2012.

Detailed decomposition of retail electricity price for industrial consumers was not available through the energy regulator. Based on Eurostat data, in the year 2012 71% of retail electricity prices bills was related to wholesale energy costs, 24% to network costs and 4% to taxes and charges.

**Figure 133: Price components of electricity bills in the UK in 2012**

![Breakdown of average household electricity bill in 2012](image)

**Source:** (DECC 2013)

Figure 134 shows the individual price components for an average household gas bill:

- Wholesale prices account for 55% of the final prices, other supplier costs and margins for 17%, network charges 18%;
- Both VAT and charges related to energy and climate change policies account for 5%;

According to (DECC 2012) average price paid by households increased by 18% in between 2010 and 2012.
In conclusion, the United Kingdom has seen increases in both electricity and retail gas prices. In the case of natural gas, the importance of wholesale energy costs might influence the final price, particularly since the country has started importing natural gas resources and cannot rely on national production only. The case study also shows how recent policy for the promotion of efficiency and renewable energy might have contributed to higher electricity prices, particularly for domestic households.
POLICY DEPARTMENT A
ECONOMIC AND SCIENTIFIC POLICY

Role
Policy departments are research units that provide specialised advice to committees, inter-parliamentary delegations and other parliamentary bodies.

Policy Areas
- Economic and Monetary Affairs
- Employment and Social Affairs
- Environment, Public Health and Food Safety
- Industry, Research and Energy
- Internal Market and Consumer Protection

Documents