Least-cost options for integrating intermittent renewables

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Introduction

• Stricter climate policies increasingly likely
• Power sector in a state of change
  ▪ More intermittent renewables: wind and solar PV
  ▪ Large CO$_2$ emission reductions: only a role for low-carbon power plants

• Effect of intermittent renewables?
• Role of emerging technologies?
  ▪ Carbon Capture and Storage (CCS)
  ▪ Demand response
  ▪ Increased interconnection capacity
  ▪ Electricity storage
Study methods

• Goal of our research: identify which technologies may be part of a centralized power system with:
  § High reliability (LOLP <0.1 day/year)
  § Low emissions (>96% reduction CO₂ emissions)
  § Low costs (key performance parameter)

• Europe in 2050

• Three scenarios:

<table>
<thead>
<tr>
<th>RES</th>
<th>40%</th>
<th>60%</th>
<th>80%</th>
</tr>
</thead>
<tbody>
<tr>
<td>iRES</td>
<td>22%</td>
<td>41%</td>
<td>59%</td>
</tr>
</tbody>
</table>
1. Define **non-fossil** capacity per scenario

2. Define capacities of **complementary** options

3. Optimize **fossil** capacity per scenario [PLEXOS]

4. Run **hourly simulations** [PLEXOS]
Study results – power generation

• Two aspects can reduce total system costs
  ▪ Least-cost power generation
  ▪ Efficient system operation

• First: what is the cheapest way to generate power in low-carbon power systems?
Study results – power generation

- Fossil capacity optimization: only natural gas capacity
  - Combined cycle with CCS
  - Gas turbines
Study results – power generation

- NGCC-CCS generates power during the night in the summer
Study results – power generation

- NGCC-CCS baseload generation during winter time
- Gas turbines supply peak demand
Study results – power generation

- CO₂ emission reduction target is met in all scenarios
  - Specific emissions of <13g/kWh correspond to a >96% reduction in CO₂ emissions

![CO₂ emissions and storage per scenario graph](image-url)
Study results – power generation

- Effect on costs: intermittent renewables increase total system costs
  - 12% higher capital costs
  - 18% reduction in electricity price
Study results – system operation

- Which options can decrease system costs by improving “system efficiency”? 
  - More efficient use of power plants
  - Less curtailment
Study results – system operation

- Interconnects reduce costs up to a ‘sweet spot’
- Storage increases total system costs
- Demand response reduces costs by 2-3%

Effect of CAES and Interconnection Capacity on Total System Costs

- Interconnects reduce costs up to a ‘sweet spot’
- Storage increases total system costs
- Demand response reduces costs by 2-3%

Study results – system operation
Conclusions

• Intermittent renewables affect the operation of power systems, but their impacts are manageable.
  ▪ Larger reserves, effect on capacity factors of other generators

• Low-carbon power systems can be realized with various generation portfolios
  ▪ Intermittent renewables increase total system costs
  ▪ Natural-gas fired generation important in all scenarios
  ▪ Demand response & interconnections least-cost options
  ▪ Electricity storage too expensive
The bigger picture

- Future power systems will become increasingly complex
  - New technologies
  - More decentralized generation
  - Cross-sectoral integration
  - More uncertainty for investors

- Necessary investments in power plants will not be made with the current energy-only market design
  - Business cases are unsound.
  - Generation adequacy may become a key issue of future power systems
Recommendations

- Support demonstration projects
  - No regret options
- Investigate the effects of cross-sectoral integration
- Investigate how future capacity can be delivered
- Develop stochastic power system simulation models
Thank you for your attention

Any questions?

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Supplementary slides
Overview of method

**Input data**

1. Low-carbon scenarios from previous studies
2. Projected load patterns
3. Projected iRES production patterns
4. Projected power plant flexibility parameters
5. Projected balancing reserve patterns
6. Projected power plant techno-economic data
7. Projected interconnection capacity
8. Projected demand response potential and costs
9. Projected techno-economic specifications of electricity storage

**Method**

1. Define plausible non-fossil generation scenarios
2. Define capacities of complementary technologies (excluding fossil)
3. Run PLEXOS LT plan to optimize fossil generation capacity
   The full generation mix is now defined
4. Run PLEXOS MT and ST schedules to optimize hourly unit commitment and economic dispatch model for western Europe

**Results**

1. Comparison of complementary technologies
2. Overview of full generation mixes
3. Costs and CO₂ emissions per scenario
4. Effect of demand response
5. Effect of electricity storage and inter-connection capacity
6. iRES integration costs:
   - Balancing costs
   - Profile costs
7. Profitability of generators
8. Sensitivity analyses
### Key input parameters

<table>
<thead>
<tr>
<th>€/GJ</th>
<th>Coal</th>
<th>Natural gas</th>
<th>Uranium</th>
<th>Biomass</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel price</td>
<td>1.7</td>
<td>6.5</td>
<td>1</td>
<td>7.2</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>€/tCO₂</th>
<th>Transport and storage</th>
</tr>
</thead>
<tbody>
<tr>
<td>CO₂ costs</td>
<td>13.5</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>TWh/yr</th>
<th>Britain</th>
<th>Scandinavia</th>
<th>France</th>
<th>Germany +</th>
<th>Iberian pen.</th>
<th>Italy+</th>
</tr>
</thead>
<tbody>
<tr>
<td>Load</td>
<td>415</td>
<td>368</td>
<td>602</td>
<td>811</td>
<td>358</td>
<td>525</td>
</tr>
</tbody>
</table>
## Input parameters of generation technologies

<table>
<thead>
<tr>
<th>Generator</th>
<th>Investment (TCR, €/kW)</th>
<th>Fixed O&amp;M (€/kW/yr)</th>
<th>Variable O&amp;M (€/MWh)</th>
<th>Efficiency</th>
<th>Remarks</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>4841</td>
<td>103</td>
<td>1</td>
<td>33%</td>
<td></td>
</tr>
<tr>
<td>PC-CCS</td>
<td>2847</td>
<td>33</td>
<td>5.6</td>
<td>41%</td>
<td>90% CO₂ capture</td>
</tr>
<tr>
<td>NGCC-CCS</td>
<td>1349</td>
<td>15</td>
<td>2.1</td>
<td>56%</td>
<td>90% CO₂ capture</td>
</tr>
<tr>
<td>NGCC</td>
<td>902</td>
<td>11</td>
<td>1.2</td>
<td>63%</td>
<td></td>
</tr>
<tr>
<td>Biothermal</td>
<td>1949</td>
<td>37</td>
<td>3</td>
<td>45%</td>
<td>100% biomass fired</td>
</tr>
<tr>
<td>Geothermal</td>
<td>2657</td>
<td>44</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Hydro</td>
<td>3037</td>
<td>52</td>
<td>0</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Wind onshore</td>
<td>1402</td>
<td>37</td>
<td>0</td>
<td></td>
<td>CF: 22-26%</td>
</tr>
<tr>
<td>Wind offshore</td>
<td>2655</td>
<td>83</td>
<td>0</td>
<td></td>
<td>CF: 40-43%</td>
</tr>
<tr>
<td>Solar PV</td>
<td>700</td>
<td>17</td>
<td>0</td>
<td></td>
<td>CF: 11-21%</td>
</tr>
<tr>
<td>Gas turbine</td>
<td>438</td>
<td>10</td>
<td>0.8</td>
<td>42%</td>
<td></td>
</tr>
<tr>
<td>Pumped hydro</td>
<td>2079</td>
<td>58</td>
<td>0.23</td>
<td>80%</td>
<td>80% round trip η</td>
</tr>
<tr>
<td>Demand resp.</td>
<td>3-100</td>
<td>1-11</td>
<td>0</td>
<td>100%</td>
<td>1-2 hrs of “storage”</td>
</tr>
</tbody>
</table>
Demand response potential

Demand Response potential used in this study

- Italy and Alpine states
- Iberian peninsula
- Scandinavia
- Germany & Benelux
- France
- British Isles

- Shed - Electrolysis
- Shed - Chloralkali
- Shed - Paper
- Shed - Steel
- Shed - Cement
- Shift - 2h by 1h
- Shift - 2h by 2h
- Shift - Airconditioning
- Shift - Washing machines / dryers
- Shift - Fridge and freezer
- Shift - Space/water heating

DR Potential (MW)
Detailed total system costs
Capacity factors per month
2. Methods

- Interconnection capacity
  - Deployment based on previous studies
  - Costs of 28 k€/MW/yr
- Demand response
  - Potential based on other studies (11 categories)
  - Crude costs of 200-5000 €/MWh (shedding) and 2-100€/kw (shifting)
2. Methods

- Two optimizations with PLEXOS
  - Power system simulation and optimization tool

- Optimization of fossil capacity
  - IEA projections of specifications
  - 6 generator types

- Hourly simulations
  - Chronological simulations with 8760 steps
  - Account for flexibility constraints
  - Auxiliary reserves also included
  - Curtailment of RES allowed
Study results – power generation

- NGCC-CCS generates power during the night in the summer
Study results – power generation

- CO₂ emission reduction target is met in all scenarios
  - Specific emissions of <13g/kWh correspond to a >96% reduction in CO₂ emissions
Study results – system operation

Effect of CAES and Interconnection Capacity on Total System Costs

- 95 GW CAES
- 0 GW CAES
- 80% RES
- 60% RES
- 40% RES

Total System Costs (€bn/y)

Current (37 GW)
Min (86 GW)
Low (123 GW)
Med* (189 GW)
High (257 GW)
Max (349 GW)

95 GW CAES
0 GW CAES
80% RES
60% RES
40% RES
3. Results – power generation

- Total system costs are also increased by the integration costs of intermittent RES:
  - Profile costs
  - Balancing costs, grid costs

![Profile integration costs of intermittent renewables](image-url)
(3. Results – economics)
(4. Sensitivities – key findings)

• Results are overall robust. Results are only considerably affected by:
  - High gas price (7.8 €/GJ) → shift of NGCC-CCS to PC-CCS
  - Cheaper biomass (5.5 €/GJ) → biomass early in merit order
  - Higher CO2 cap (180 Mt) → shift of NGCC-CCS to NGCC
  - Lower investment costs of iRES → lower system costs

• More flexibility in systems resulting from interconnections, DR or CAES leads to
  - More base-load generation
  - Less GT capacity being installed and used

• Investment costs of iRES are a key factor.
  - Reduction in iRES investment costs has a large impact
  - Overall iRES cost reduction of >31% required to make 80% RES the cheapest scenario
## Total System Cost

60% RES Base = 241.3 €bn/y

*60% RES, Cap 45MT, CAES 0%, Exch 189 GW, DSM 34 GW, NG 6.5 €/GJ, BIO 7.2 €/GJ*

<table>
<thead>
<tr>
<th>Total System Cost (€bn/y)</th>
<th>40% RES</th>
<th>60% RES</th>
<th>80% RES</th>
</tr>
</thead>
<tbody>
<tr>
<td>210</td>
<td>234.0</td>
<td>246.1</td>
<td>264.0</td>
</tr>
<tr>
<td>215</td>
<td>231.4</td>
<td>243.7</td>
<td>258.9</td>
</tr>
<tr>
<td>220</td>
<td>230.0</td>
<td>241.3</td>
<td>257.1</td>
</tr>
<tr>
<td>225</td>
<td>227.0</td>
<td>238.4</td>
<td>254.8</td>
</tr>
<tr>
<td>230</td>
<td>215.3</td>
<td>231.9</td>
<td>250.9</td>
</tr>
<tr>
<td>235</td>
<td>222.3</td>
<td>236.3</td>
<td>253.6</td>
</tr>
<tr>
<td>240</td>
<td>230.0</td>
<td>241.3</td>
<td>257.1</td>
</tr>
<tr>
<td>245</td>
<td>234.1</td>
<td>243.3</td>
<td>257.5</td>
</tr>
<tr>
<td>250</td>
<td>226.6</td>
<td>236.3</td>
<td>250.7</td>
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<tr>
<td>255</td>
<td>230.0</td>
<td>241.3</td>
<td>257.1</td>
</tr>
<tr>
<td>260</td>
<td>229.1</td>
<td>241.3</td>
<td>256.3</td>
</tr>
<tr>
<td>265</td>
<td>230.4</td>
<td>241.3</td>
<td>249.2</td>
</tr>
<tr>
<td>270</td>
<td>226.6</td>
<td>241.3</td>
<td>249.2</td>
</tr>
<tr>
<td>275</td>
<td>230.4</td>
<td>241.3</td>
<td>249.2</td>
</tr>
</tbody>
</table>

**DSM**
- 0% DSM (0 GW)
- 50% DSM (17 GW)
- 100% DSM (34 GW)
- 200% DSM (68 GW)

**Fuel Prices**
- Gas 3.9 €/GJ
- Gas 5.2 €/GJ
- Gas 6.5 €/GJ
- Gas 7.8 €/GJ
- Bio 5.5 €/GJ

**Emission Cap**
- *45 MT
- 60 MT
- 180 MT

**CAES (Med Exchange)**
- *0% (0 GW)
- 1% (4.8 GW)
- 5% (23.7 GW)
- 10% (47.6 GW)
- 20% (95.1 GW)

**Exchange Capacity (% CAES)**
- Cur (36.7 GW)
- Min (86.4 GW)
- Low (123 GW)
- *Med (189 GW)
- High (257 GW)
- Max (349 GW)

**iRES Investment Costs**
- iRES -10%
- iRES -20%
- Solar PV 500€/kW
- Solar PV 1095€/kW
- No Pumped Hydro
- Alternative Demand Profile


4. Discussion – scope, assumptions

- This study only considers snapshots of possible future power systems in 2050. No consideration is given to the dynamic transition from the current system.
- Starting points of this study are pre-set emission reduction and reliability targets.
- Heating (demand, generation, storage) is not included.
- No transmission constraints are simulated within regions.
- Assumed properties of DR capacity:
  - 49 GW of DR potential
  - Shedding costs in this study: 200-5000€/MWh
  - Shifting investment cost in this study: 2-100 €/kW
4. Discussion - caveats

- The scenario approach fixes 50-65% of the costs exogenously leaving less room for optimization. Thus systems are plausible, not necessarily optimum. This may be reflected in the costs.
- Capacity credits of iRES are fixed. This assumption:
  - Underestimates the benefits of interconnections (interconnectors can increase the capacity credit by spatial smoothing);
  - Underestimates the profile costs in the 80% RES scenario compared to the 40% RES scenario (capacity credits decrease with higher iRES capacity, requiring more firm capacity with low capacity factors).
- Significant uncertainties remain about the potential and costs of DR
- The model does not include specialized VOLL-values, or a detailed representation of super-peak generators (e.g. backup generators). These could improve the profitability of power plants by causing price spikes, which lead to big profits in a small amount of time.