Integration of High Penetration of Solar and Wind Power in Power Systems: Experiences and Challenges
Lecture 8-9+ Tutorial 4

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Set-up of Lectures L9-L10 + T3

Lecture L8: Methods for large scale integration and results.

Lecture L9: Capacity credit and capacity markets

Tutorial T3: Power System expansion planning, impact from assumptions

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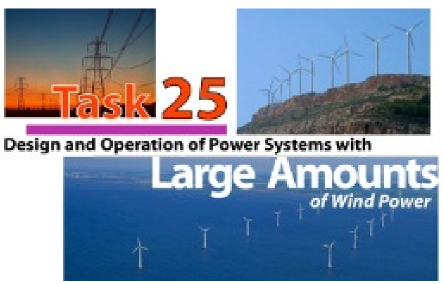

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Recommendations for Wind and Solar Integration Studies

SIW/WIW Berlin, 25th Oct 2017

Hannele Holttinen, Principal Scientist, VTT

Operating Agent, IEA WIND Task 25

J. Kiviluoma (VTT, Finland), T. K. Vrana (SINTEF, Norway), E. Neau (EdF, France), D. Flynn & J. Dillon (UCD, Ireland), L. Söder (KTH, Sweden), N. Cutululis (DTU, Denmark), B. Mather & B.-M. Hodge (NREL, USA), K. Ogimoto (Uni Tokyo, Japan), E.M.Carlini (Terna, Italy) J.C.Smith (UVIG, USA)

Contents

- Flow chart of a complete integration study - recommendations for the individual steps
  - Input data
  - Portfolio set-up
  - Capacity value/Reliability
  - Flexibility/production cost simulations
  - (Load flow and dynamic stability – presented by Damian Flynn)
  - Analysing and interpreting results
- Future work and Summary

Recommended Practices

- Purpose: to provide research institutes, consultants and system operators with the best available information on **how to perform a wind integration study**
- **Also for benchmarking** studies: what has been taken into account, what has not
- Information about **methodology** only – Summary report contains summary of recent study results
- RP16 Published in the series of Recommended Practices for International Energy Agency's Wind Implementing Agreement at


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EXPERT GROUP REPORT ON
RECOMMENDED PRACTICES
16. WIND INTEGRATION STUDIES

1. EDITION 2013

tted to the Executive Committee
al Energy Agency Implementing Agreement
for
e Research, Development, and Deployment
of Wind Energy Systems

Approved Sept. 12, 2013

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IEA Wind Task 25

TECHNOLOGY
268

Design and operation of power systems with large amounts of wind power

Final summary report, IEA WIND Task 25, Phase three 2012–2014

Recommended practices update in 2017

- Edition 2 including
  - Wind **and solar** PV,
  - Transmission **and distribution**
- Timetable
  - November: review process of IEA WIND
  - Voting/ballot in December/January

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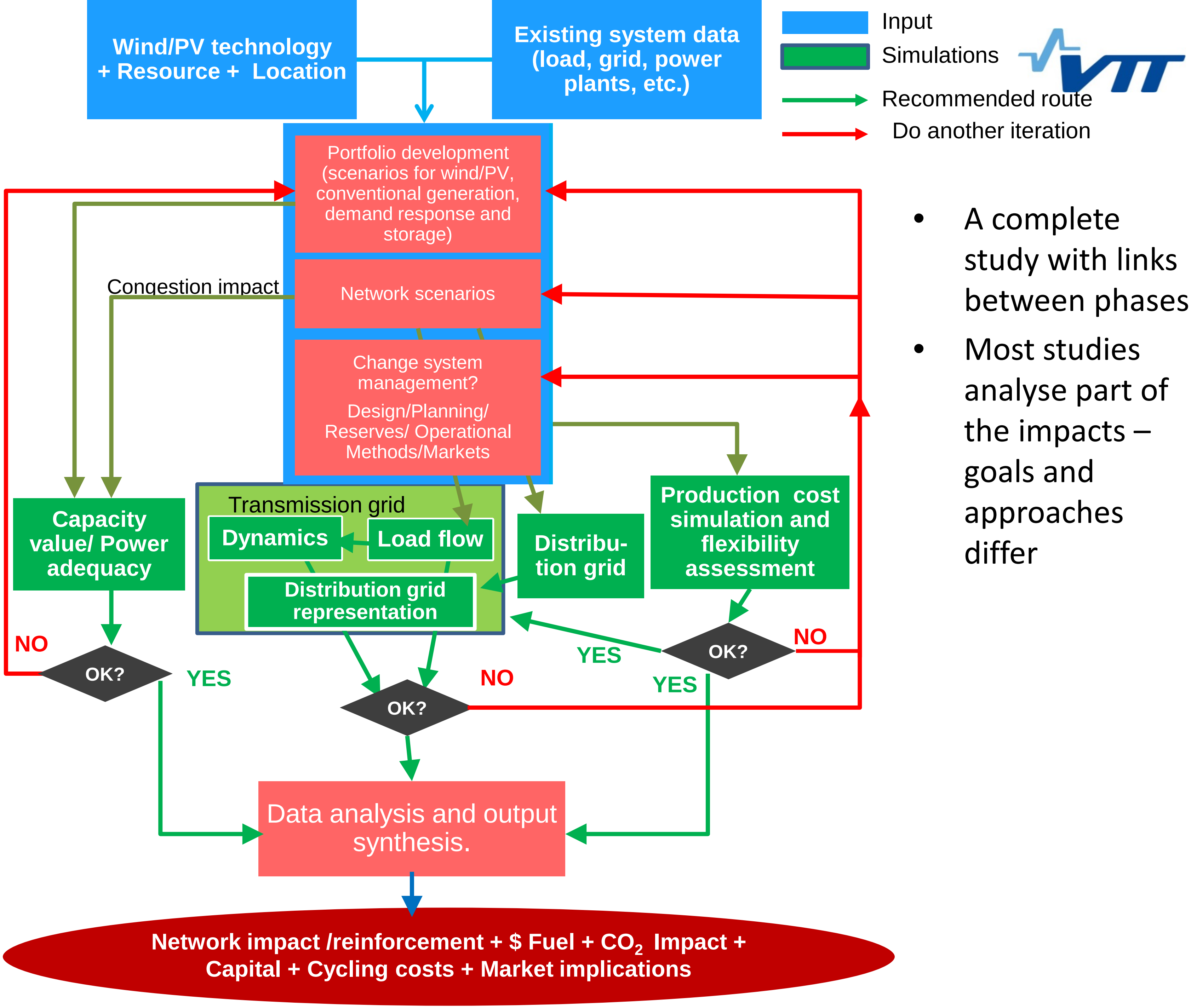
EXPERT GROUP REPORT ON
RECOMMENDED PRACTICES

16. WIND/PV INTEGRATION STUDIES

2. EDITION 2017

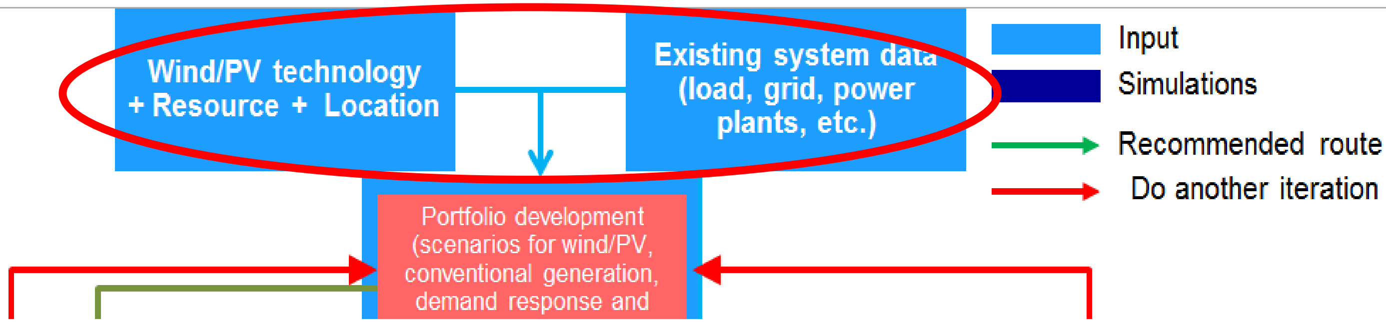
Submitted to the Executive Committees
of the International Energy Agency TCPs
for
Co-operation in the Research, Development, and Deployment
of Wind Energy Systems
and PVPS

Fourth draft October 16th 2017

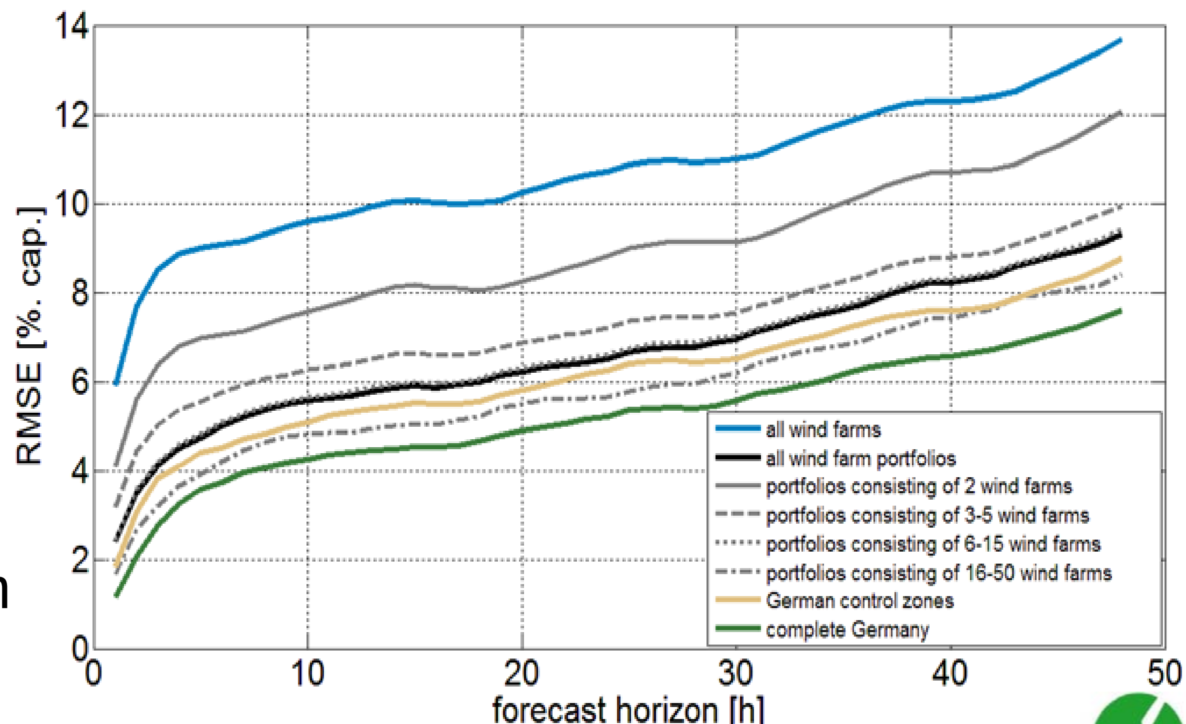


- A complete study with links between phases
- Most studies analyse part of the impacts – goals and approaches differ

Input data



- Data needs are different for different simulations
- Wind/PV data inputs important to get right for a future scenario:
  - representative for power system area, smoothing effect
- Also remaining system and technologies may …ge in future

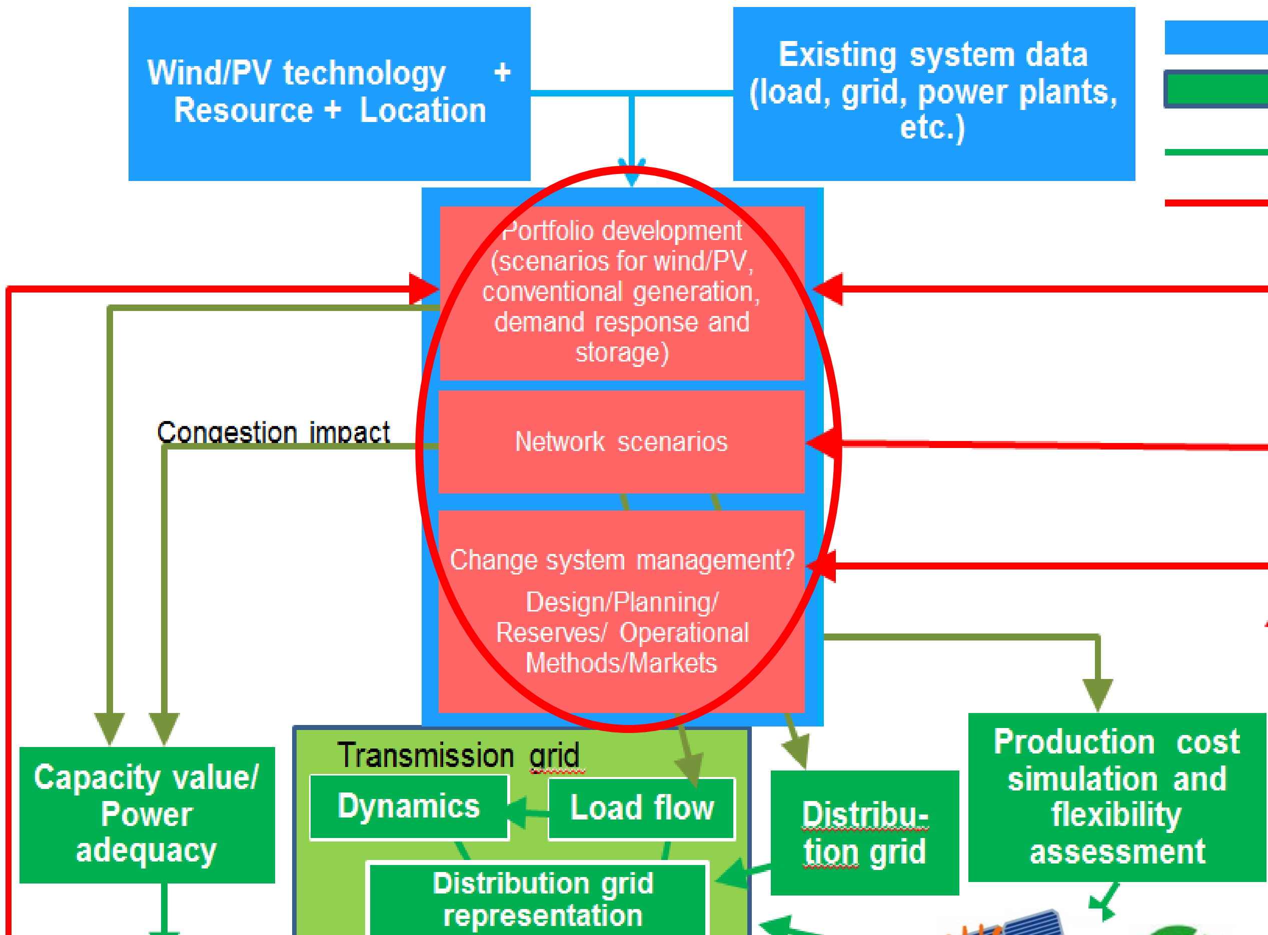


Recommendations for input data

	Capacity Value / Power (resource) Adequacy	Unit Commitment and Economic Dispatch (UCED)	Power flow	Dynamics
Wind /PV	Hourly generation time series for distributed wind/PV energy covering the area. Especially for wind at least 10 years recommended	5-minute to hourly generation time series of at least 1 year for distributed wind/PV power covering the area	Wind power capacity at nodes, high and low generation and load snapshots, active and reactive power	Wind power capacity at nodes, high and low generation snapshots, dynamic models of turbines, operational strategies
Wind / PV short term Forecasts	Not needed	Forecast time series, or forecast error distribution for time frames of UCED	Will be needed in future	Not needed
Load	Hourly time series synchronous with wind/PV data, at least 10 years recommended	5-minute to hourly time series synchronous with wind/PV, of at least 1 year	Load at nodes, snapshots relevant for wind/PV integration	Load at nodes, high and low load snapshots, dynamic capabilities
Load Forecasts	Not needed	Forecast time series, or forecast error distribution for time frames of UCED	Will be needed in future	Not needed
Network	Cross border capacity, if relevant	Transmission line capacity between neighbouring areas and / or topology and line reactances for SCUC studies	Network configuration, circuit passive and active parameters	Network configuration, circuit parameters, control structures
		Min, max on-line capacity, start-up	Active and reactive	

Portfolio Development and System Management

- Set-up of study
- Main assumptions
  –Critical for results!
- Future system, how wind/PV is added, what is remaining generation mix, network, operational practices
- Main interation loops and use of sensitivities

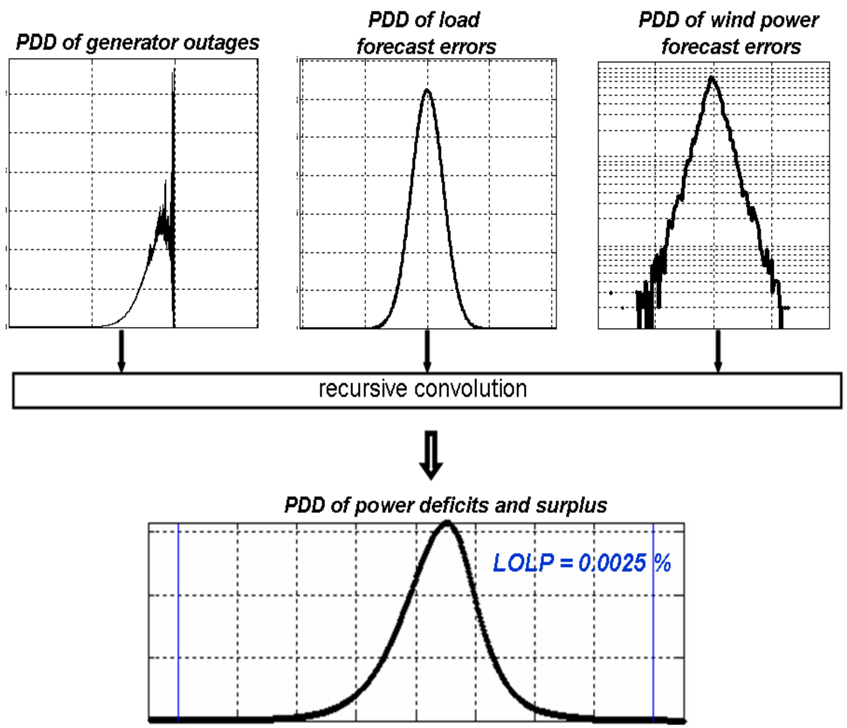


Recommendations for set-up

1. When studying small amounts of wind/PV power (share in energy <5-10 %), or short term studies, wind/PV power can be studied by adding wind/PV to an existing or foreseen system, with existing operational practices.
2. For larger shares and longer term studies,
   - changes in the assumed remaining system become increasingly necessary, and beneficial: expedient generation portfolio and network infrastructure development, taking into account potential sources of flexibility (also demand response) and technical capabilities of power plants (dynamic stability responses).
   - additional scenarios or operating practices should be studied. Market structures/design to enable operational flexibility, should be assessed.

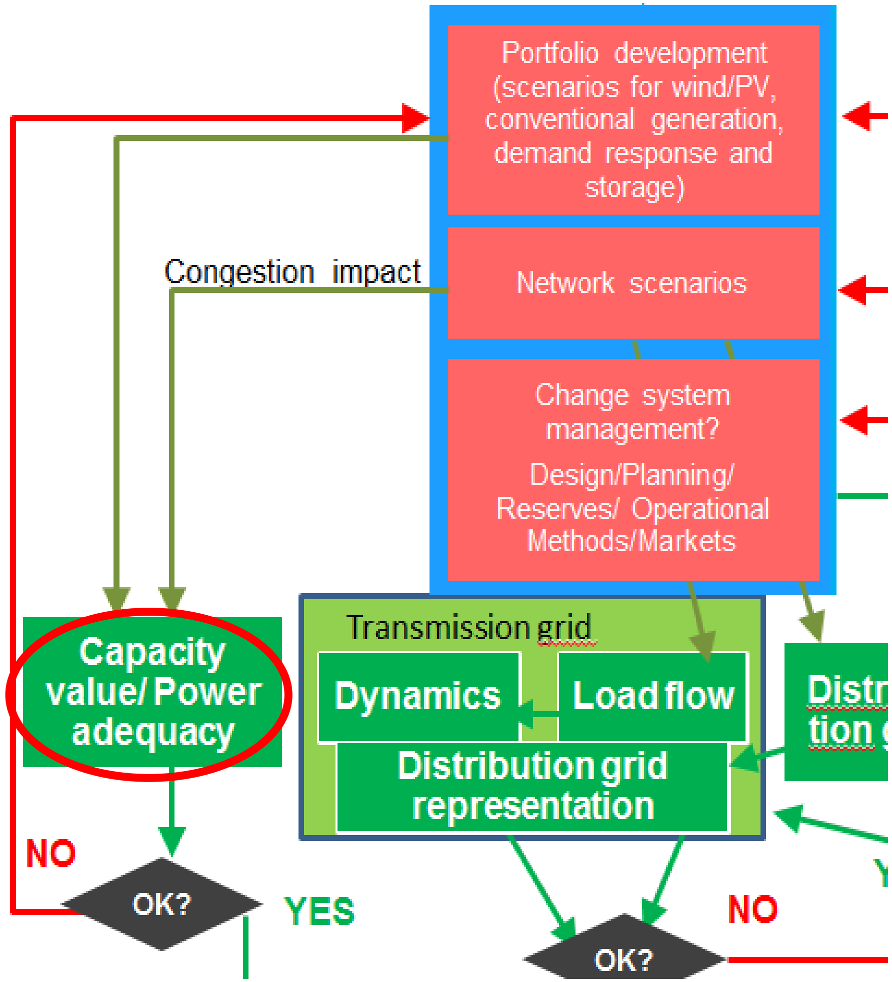
Reserve allocation with wind and PV

1. Synchronous wind/PV and load time series + wind/PV and load forecast error distributions + generation outage distribution
2. Calculate for appropriate time scales, f.ex. automatically responding (secs-mins) and manually activated (mins-hour). Split data for categories with care not to double-count.
3. Combine uncertainty and short term variability, keeping the same risk level before and after adding wind/PV. Variability and uncertainty not normally distributed → level of exceedance, or distribution recommended
4. With increasing shares, use dynamic,



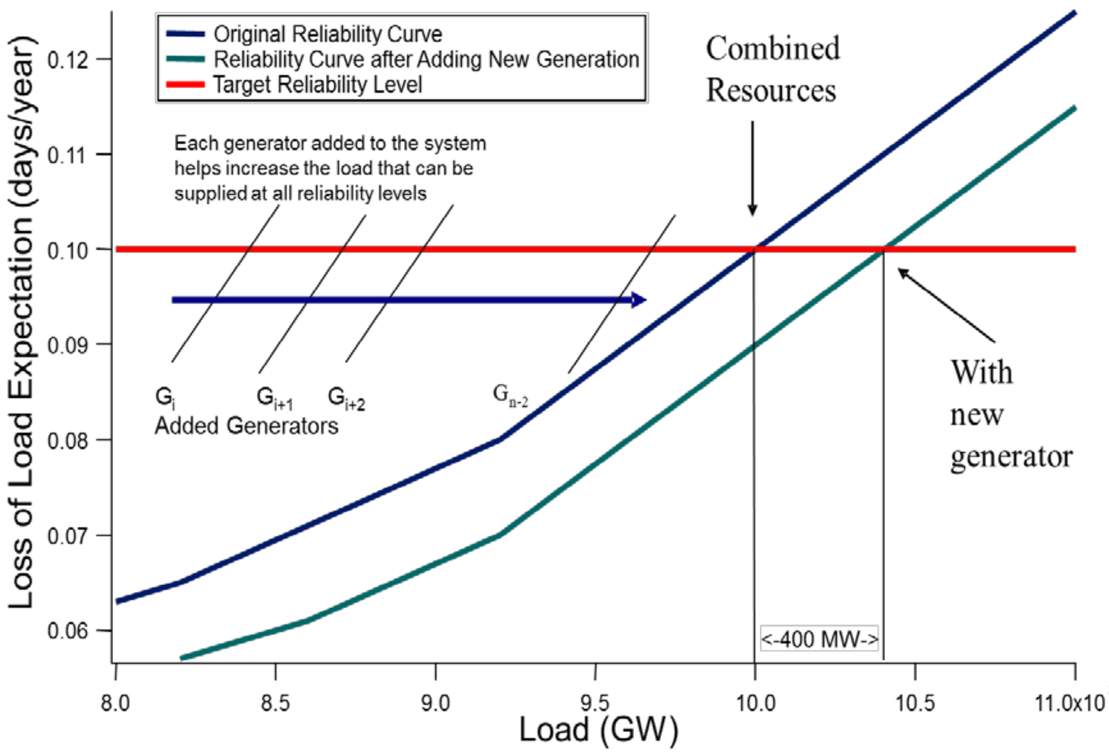
Generation capacity adequacy

- Needed for making consistent future scenarios (how much capacity will wind/PV replace)
- As integration study result: capacity value of wind or solar PV



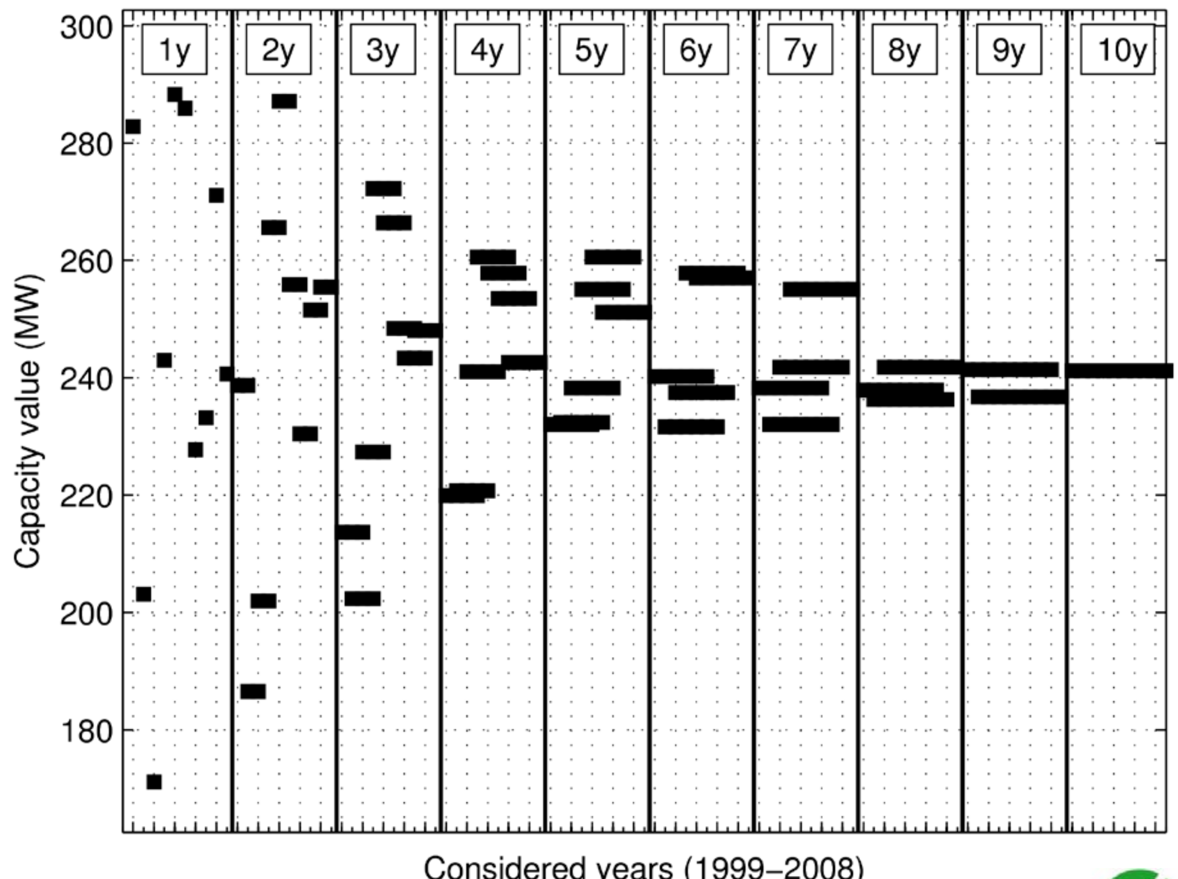
Capacity Value of wind and solar

- How much increase in load will bring same reliability/LOLP in the system when adding wind or solar (ELCC method) recommended



Input data – synchronous wind/PV/load data. Number of years critical for robust results

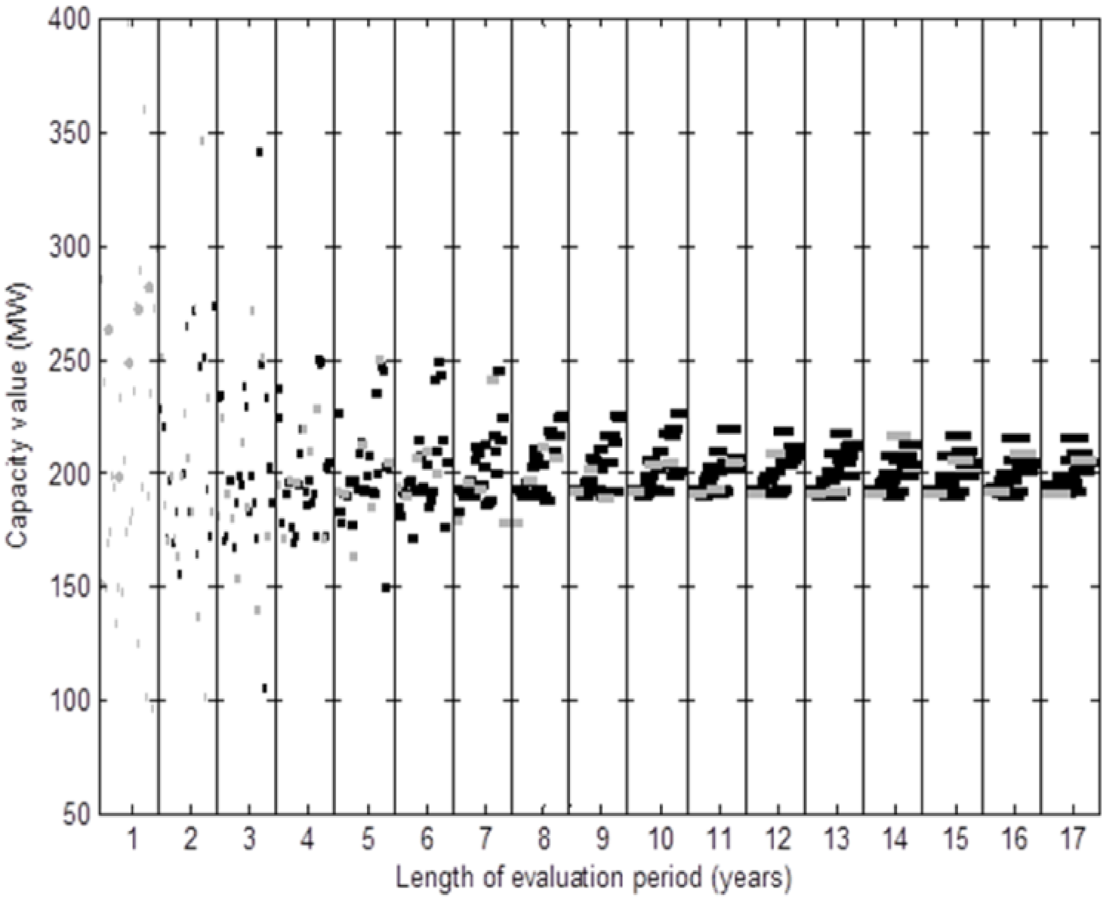
- Case Ireland, using 10 years of data



Source: Hasche, B.; Keane, A.; O'Malley, M. (2011). "Capacity Value of Wind Power, Calculation and Data Requirements: The Irish Power System Case." *IEEE* *…ions on Power* …(26:1); pp. 420–430

Input data – synchronous wind/PV/load data. Number of years critical for robust results

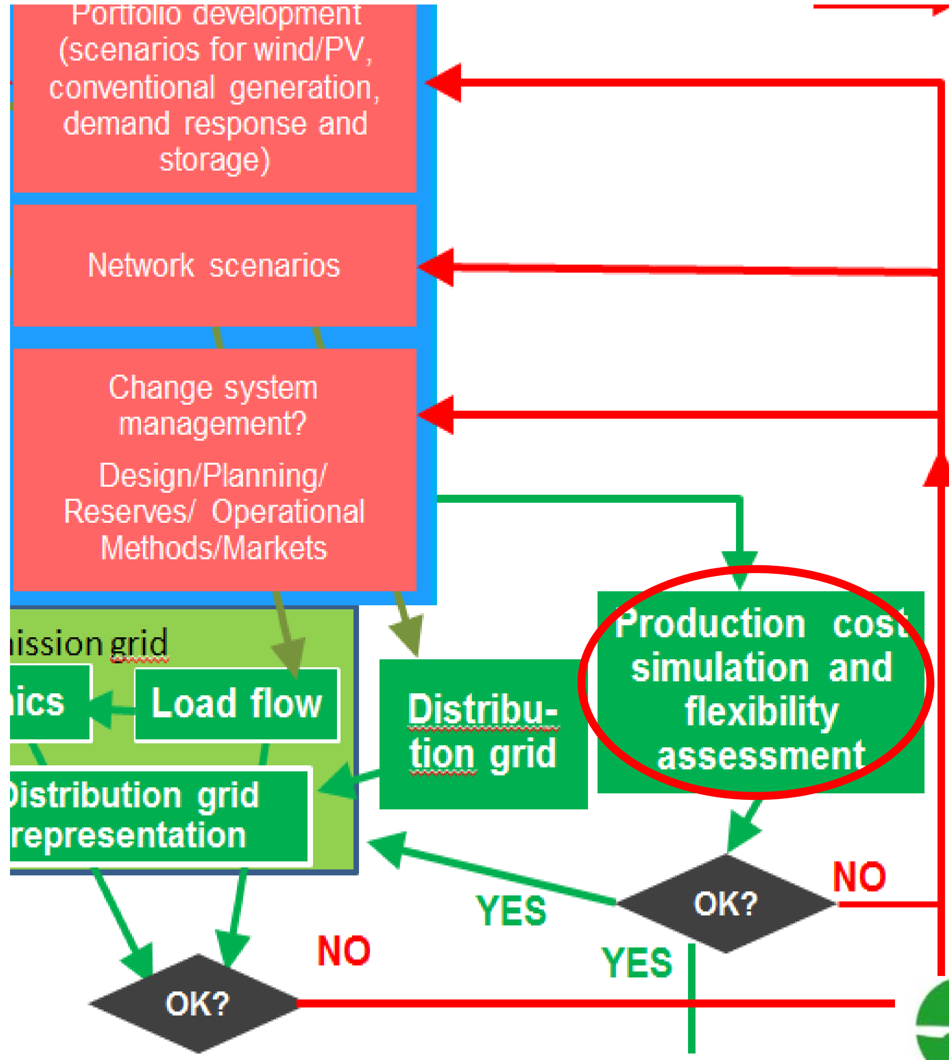
- Latest results show that 10 years not enough, will still produce ± 10 % uncertainty in results
- Case Finland using 35 years of data



rce: M.Milligan, B.Frew, E.Ibanez, J.Kiviluoma, olttinen, L.Söder. 2017. Capacity value assessments for d power. Wiley Interdisciplinary Reviews: Energy and Environment. (6: 1)

Production cost simulation – flexibility assessment

- Impact of wind/PV on other power plants' operation
- Simulated with Unit Commitment and Economic Dispatch (UCED) tools
- Iteration loops /sensitivies often needed: change of generation mix, network reinforcements, operational practices to enable flexibility



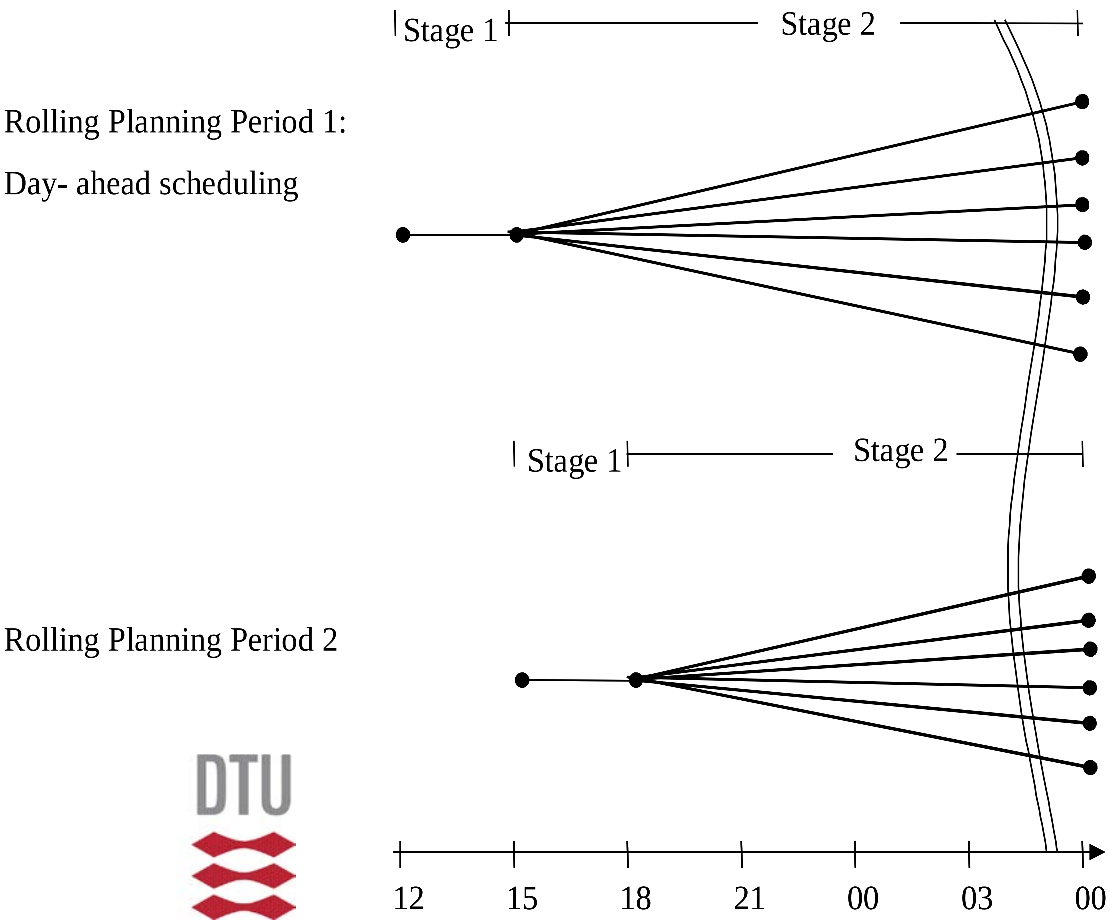
Flexibility assessment

- Separate flexibility analyses can be conducted as post-processing the data
  - Is the ramping flexibility in the dispatched generation fleet enough for the ramps foreseen

- Possibilities of flexibility resources may also be captured as an increased system value of wind and solar (IEA, 2016).

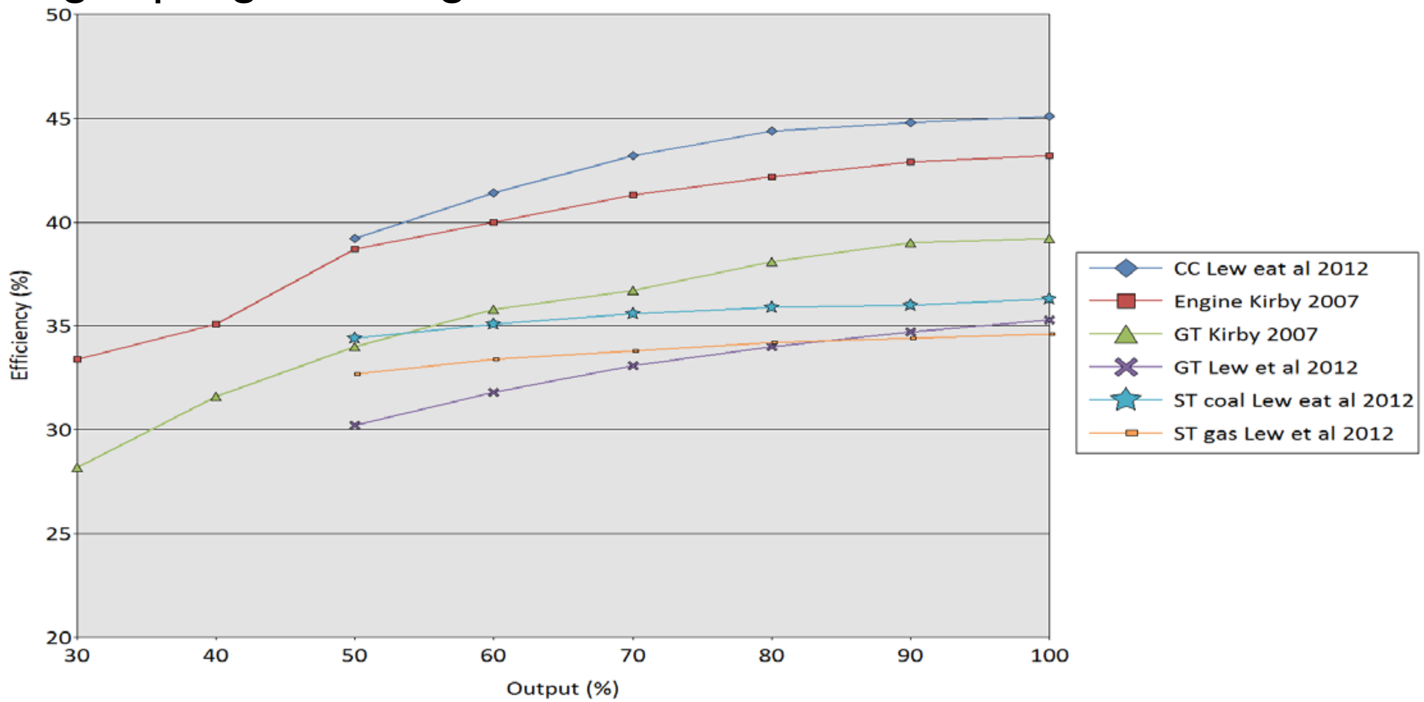
Recommendations for Unit Commitment and Economic Dispatch (UCED)

1. At least one year of at least hourly wind/PV and load data – synchronous and capturing smoothing impact and forecast accuracy. Hydrological scenarios for hydro dominated systems.
2. Model the impact of uncertainty on commitment decisions (stochastic optimization) with possibilities to update forecasts (rolling planning)



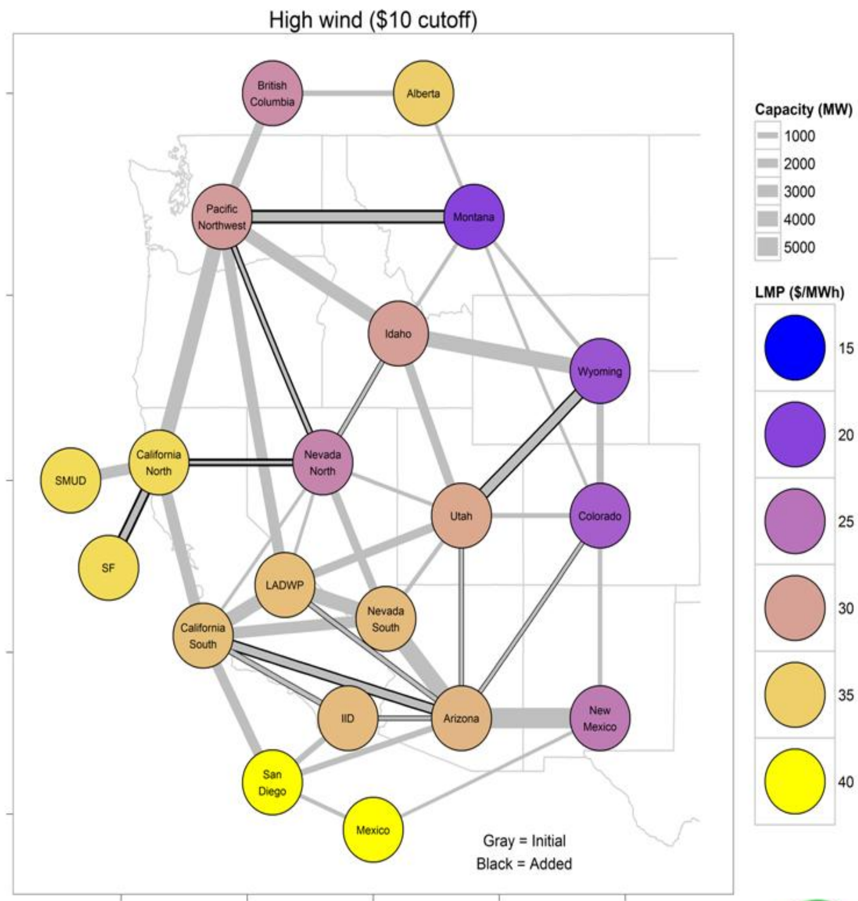
Recommendations for Unit Commitment and Economic Dispatch (UCED)

3. Increased operating reserve targets
4. Model flexibility limitations and constraints
   - Min.generation levels, ramp rates, part load efficiency, start times and costs, hydro power river flow constraints. Cycling costs to be assessed at higher penetration. May need Mixed integer programming.



Recommendations for Unit Commitment and Economic Dispatch (UCED)

5. Possibilities and limitations of interconnections
   - model neighbouring system or mention assumption (over- or underestimating transfer possibilities)
6. Limitations from the transmission network require modeling of congestion and N-1 security
   - Net transfer capacity, or

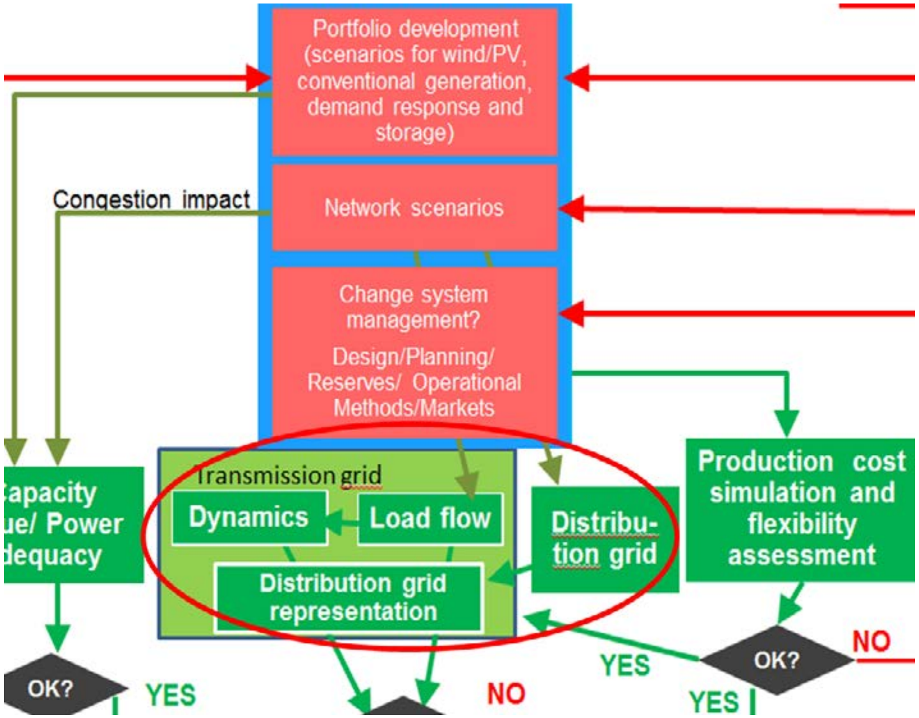


Recommendations for Unit Commitment and Economic Dispatch (UCED)

7. Include possible new flexibilities (power2heat, EVs, storages, demand response, dynamic line rating)
8. Results for impact of wind/PV sensitive to base case selection (non-wind/PV case of comparison), like what generation wind/PV will replace

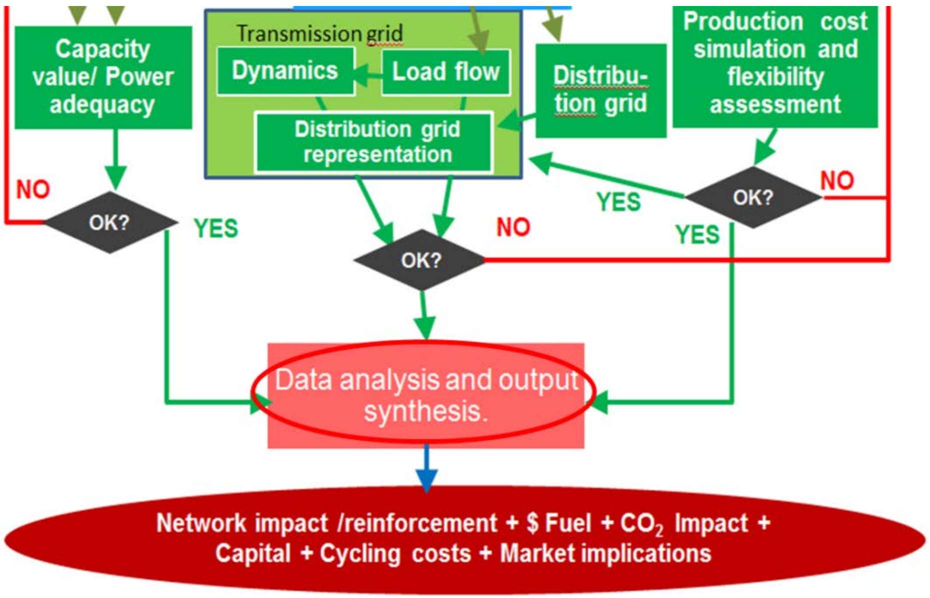
Network simulations

- Separate presentation Damian Flynn



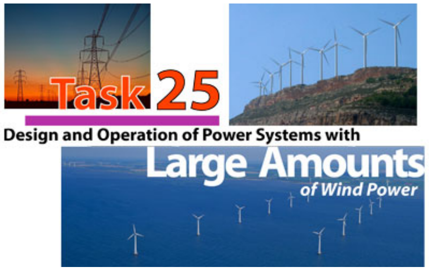
Analysing and Presenting the Results

- Iterations provide significant insights
- Comparisons to base case selected may impact results. Integration cost contradictory issue – so far no accurate methods found to extract system cost for a single technology



Future work: integration studies are still evolving, towards 100% renewable studies

- Metrics and tools for flexibility needs of the power system, and ways to achieve flexibility
- Simulation tools that consider uncertainty of wind in different time scales, and combine network constraints with UCED constraints
- Ways to set up simulation cases to efficiently extract impacts and system costs
- Stability issues with very high penetration cases. Future grids with more DC transmission.
- Implications of market design and/or regulatory processes for wind/PV integration.



IEA WIND Task 25: Design and operation of power systems with large amounts of wind power

www.ieawind.org

17 countries + Wind Europe
pate

	Country	Institution (TSO=Transmission System Operator)
	Canada	Hydro Quebec (Alain Forcione, Nickie Menemenlis)
	China	SGERI (Wang Yaohua, Liu Jun);
	Denmark	DTU Wind (Nicos Cutululis); TSO Energinet.dk (Antje Orths)
	Finland	VTT (H. Holttinen, J. Kiviluoma) – **Operating Agent**
	France	EdF R&D (V. Silva, E.Neau); TSO RTE (J.-Y. Bourmaud; Mines ParisTech (G.Kariniotakis)
	Germany	Fraunhofer IWES (J. Dobschinski); TSO Amprion (P. Tran)
	Ireland	SEAI (John McCann); EnergyReform (Mark O'Malley, Jody Dillon)
	Italy	TSO Terna Rete Italia (Enrico Maria Carlini)
	Japan	Tokyo Uni (J.Kondoh); Kansai Uni (Y.Yasuda); CRIEPI (R.Tanabe)
	Mexico	INEEL (Julio Alberto Hernández Galicia)
	Norway	SINTEF (John Olav Tande, Til Kristian Vrana)
	Netherlands	TSO TenneT (Ana Ciupuliga), TUDelft (Jose Rueda Torres);
	Portugal	LNEG (Ana Estanquiero); INESC-Porto (J. Pecas Lopes);
	Spain	University of Castilla La Mancha (Emilio Gomez Lazaro)
	Sweden	KTH (Lennart Söder)
	UK	DG&SEE (Goran Strbac, Imperial; O. Anaya-Lara, Strathclyde)

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Comparison of integration studies of 30-40 percent energy share from variable renewable sources

WIW17-49

16th Wind Integration Workshop – International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants – 25-27 October 2017, Berlin

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Comparison of integration studies of 30-40 percent energy share from variable renewable sources

WIW17-49

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Studied systems:

Area	Size (Wind/ solar mean distance)	Energy share/ year	Cap. To neigh-bors: % of wind + solar cap
Sweden	350 km	32 %	0 %
Germany	270 km	31 %	18 %
Iberia	300-370 km	42 %	0 %
Ireland	140 km	34 %	17 %
Europe-1	1000-1200 km	25 %	Internal limits
Europe-2	1000-1200 km	33 %	Internal limits
US-Minnesota	200 km	25 %	n/a

General set-up / how to compare

B: Background for each report,

D: Used data for wind, solar and other power plants as well as other data, e.g. transmission.

M: Method used to obtain results

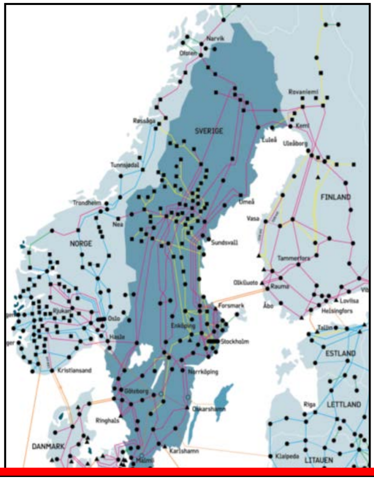
R: Results from the study

Comment: The aim → different inputs/outputs

Important: An "**input**" should **NOT** be claimed to be a "**result**"

Sweden (32% wind + solar):

Paper author: L. Söder



B: Nuclear (today 40%) will close in future. Which challenges with 100% renewables?

D: 2011 load and scaled wind+solar. No trading with neighbors. New internal planned lines considered.

M: Yearly simulation, limits for inertia, min hydro etc

Results

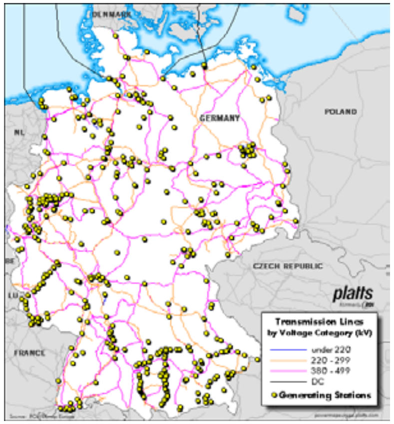
Source	Energy curtailment: % of production	Max curtailment: % of max prod.
Wind (R)	2,04 %	30%
Solar (R)	2,98 %	38%

Extra capacity (R)	5200 MW of OCGT, 1% of energy

Extra costs (R)	The costs of OCGT is 0,2 Eurocent/kWh split to all load energy.

Germany (31% wind + solar):

Paper author: C. Pellinger



B: Nuclear to be phased out. Increased wind + solar, is storage needed?

D: Planned RES increase. Capacity fixed in scenarios.

M: Yearly linearized unit commitment for 27 European countries.

Results

Source	Energy curtailment: % of production	Max curtailment: % of max prod.
Wind (D)	1,1	19
Solar (D)	< 0,01	< 0,01

CO2 reductions (R)	Up to 61 % savings compared to 1990 level

Extra costs (R)	Savings due to optimized storage expansion: 101 Mio.€/year

Iberia (42 % wind + solar):

Paper author: J. Kiviluoma

B: Study impact of using wind and solar power for frequency reserve.

D: Adding of more wind power to power system for 2012.

M: Yearly unit commitment considering wind and load forecasts. Mixed integer.

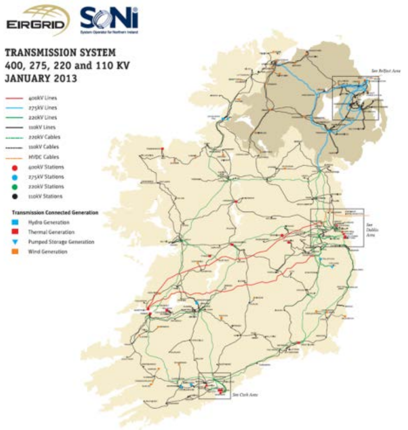
Results

Source	Energy curtailments: % of production	Max curtailment: % of max prod.
Wind (R)	2.1 % (0.1%)	40.0 %
Solar (R)	0.3 % (5.2%)	12.9 %

- (In parenthesis): wind and PV were **not allowed** to participate in frequency reserves.
- No preference whether to curtail wind power or PV

Ireland (34 % wind power):

Paper author:. Flynn



B: Study impact of using wind power the whole island.

D: Scaled wind and load data for 2020, also for GB. Forecasted other plants.

M: Yearly stochastic unit commitment considering wind and load forecasts.

Results

New / refurbished transmission (**R**)	845 km new lines at 220/275 kV and 110 kV
Transmission investment cost	1,007 M€ = 63 M€/year = 1,8% of all extra required costs.
CO2 reductions (**R**)	24% reduction, relative to low renewables (16%) reference case
Electricity Production cost savings (**R**)	30% reduction, relative to low renewables (16%) reference case

Europe-1 (25 % wind + solar):

Paper author: ENTSO-E: A. Orths

B: Study impact of wind and solar power impact on transmission. TYNDP

D: Installed capaci-ties per source and area. CO2 prices. Correlated time series.

M: Yearly, hourly and area based simulations.

Results

Source	Energy Curtailments: % of total production	Max curtailments: % of max prod.
Wind + Solar (R)	0.76%	n/a

New / refurbished Transmission (**R**)	About 100 investment needs at ~50000km (~25 Tkm DC, ~24 Tkm AC)

CO2 reductions (**R**)	Up to 80% savings compared to 1990 level

Electricity Producti-on cost savings (**R**)	2…5 EUR / MWh

Europe-2 (33 % wind + solar):

Paper authors: EDF R&D: V. Silva, M. Lopez-Botet Zulueta

B: Study impact of wind and solar power impact on transmission, flexibility, prices etc.

D: Projected installed capacities per source. Each country = a node. Correlated time series.

M: Yearly, hourly and country based simulations. Many tools

Results

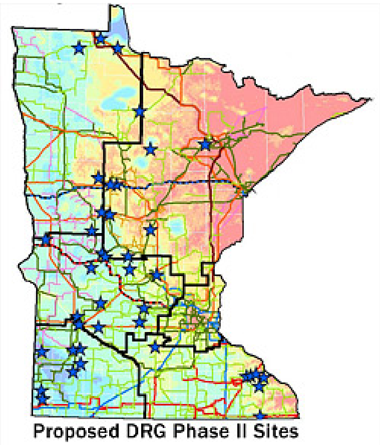
Extra production capacity (**D**)	net decrease : -90 GW (decrease in baseload generation and increase in backup capacity)

New Interconnection capacity compared to today's (**R**)	+47 GW

CO_2 reductions (**R**)	-70% Compared to 1990 levels

US-Minnesota (25 % wind + solar):

Paper authors: M. Milligan, B. O'Neill



B: Study impact from wind+solar on curtailments, unserved energy, ramp rates etc

D: Grid including parts outside Minnesota. Target year 2028 for load and production.

M: Yearly, hourly production simulation and load flow.

Results

Source	Energy Spillage: % of production	Max spillage: % of max prod.
Wind (R)	1,63 %	53,1 %
Solar (R)	0,04 %	30,1%

Extra capacity (R)	7301 MW of OCGT, 0,06 % of energy

Cost savings (R)	2.2 Euro/MWh production cost savings compared to baseline

Summary concerning 30-40 % share of variable renewables. - 1

1) **Additional storage** for system level demand-generation balancing has **not been found necessary** in any of the studies.
2) System operability, in particular, the **provision of ancillary services** and frequency stability will be **important issues** even in large interconnected systems (EDF R&D study) and wind and PV should contribute to system operability (shown in Iberia study) in future when large penetrations are to be achieved.
3) **Curtailments** are in the range of **single-digit percentages**.
4) The **maximum 1h-ramp** rate for total wind power **is in the range of 8-10%** in the studies where this data has been reported, with the exceptions of Ireland and the US-Minnesota, which are smaller systems.

Summary concerning 30-40 % share of variable renewables. - 2

5) There can be **extra costs for extra capacity** and/or for new transmission lines, but avoided costs or capacity if the wind and solar are not built. **Costs** in the range of **single Euros per MWh**.
6) Different studies have different aims, and it is important to recognise these when they are compared.
   - More wind and PV to an existing system ➔ don't need more capacity,
   - Study of future system ➔ more capacity needed.
   - Identify bottlenecks ➔ result = more lines.
   - Assumed fixed grid ➔ other solutions.
7) The possibility to **balance wind and solar in a larger area decreased the challenges** as shown in the German and US-Minnesota study.
8) **More transmission reduces the need** for curtailments.

Capacity value and capacity markets

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Power market simulations
- Capacity credit of a plant

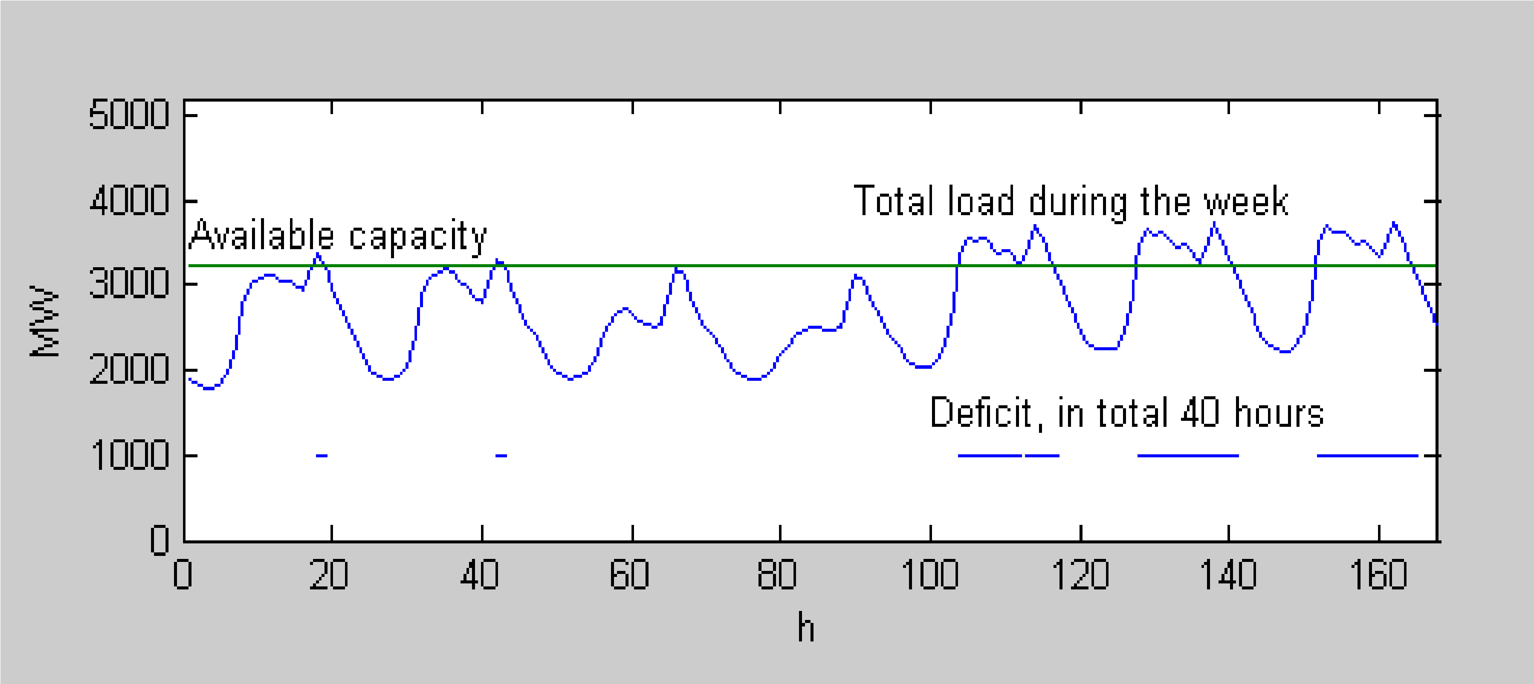
<u>Definition:</u> Capacity credit means the possibility of a power plant to increase the reliability (decrease in LOLP) of a plant

<u>Question:</u> Is there any capacity credit for wind power?

Wind Power Capacity Credit
(expressed as equivalent load increase)

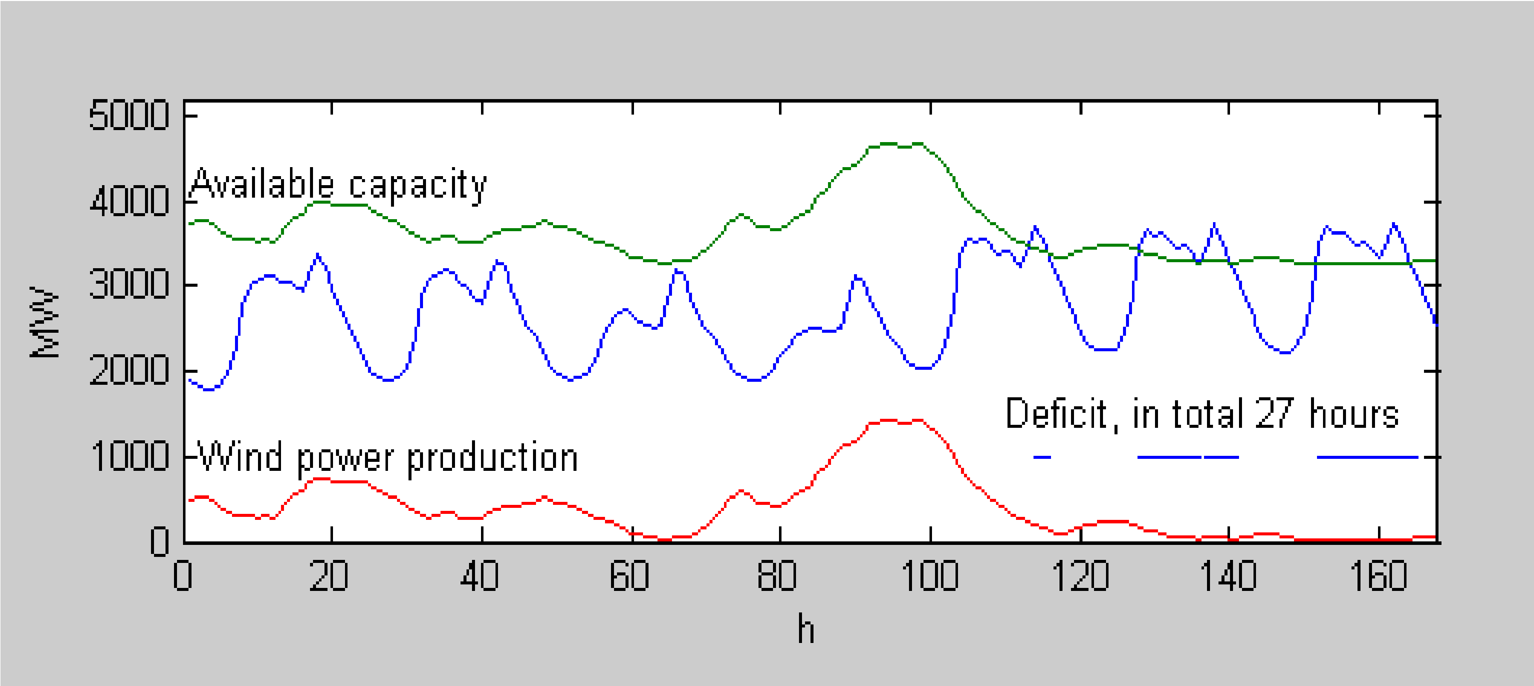
How much can the consumption increase when the amount of wind power increases and the risk of power deficit is kept constant?

Wind power capacity credit - 1



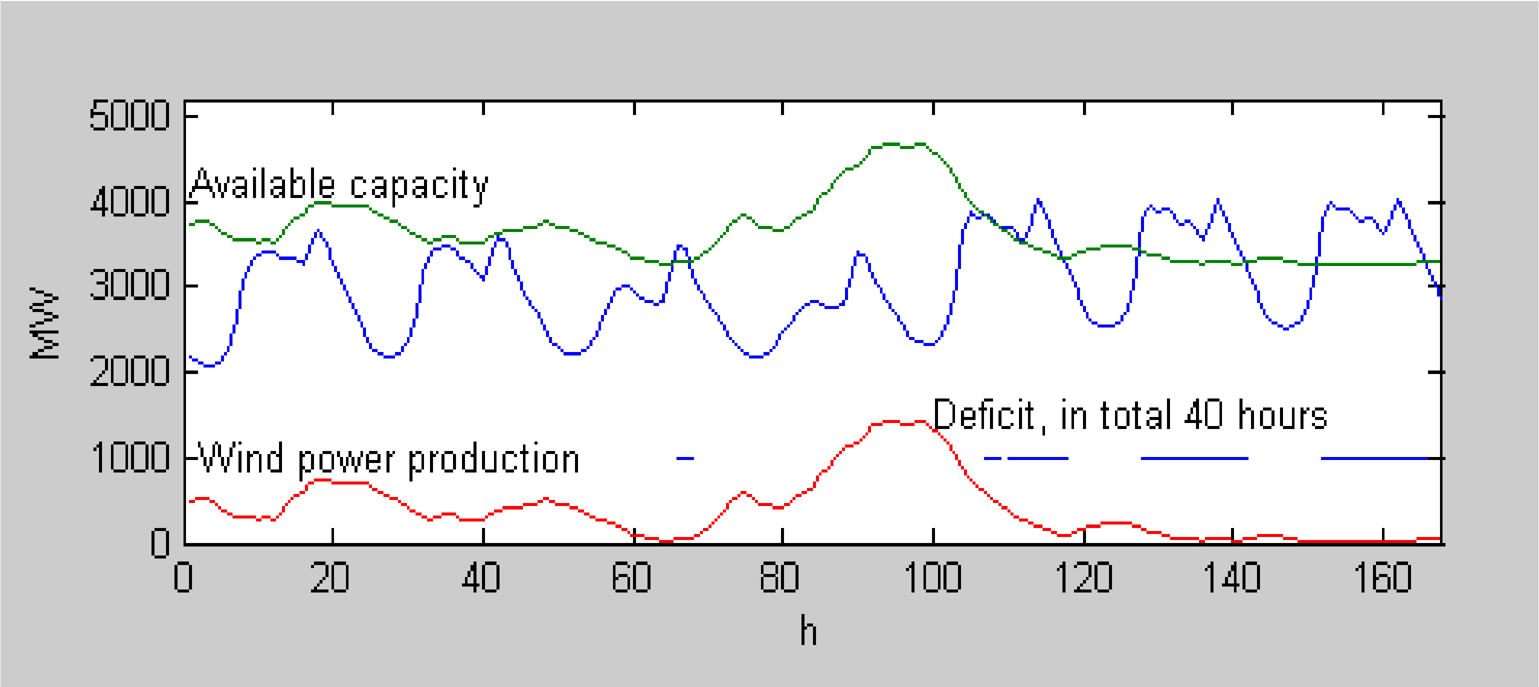
No wind power

Wind power capacity credit - 2



With wind power

Wind power capacity credit - 3



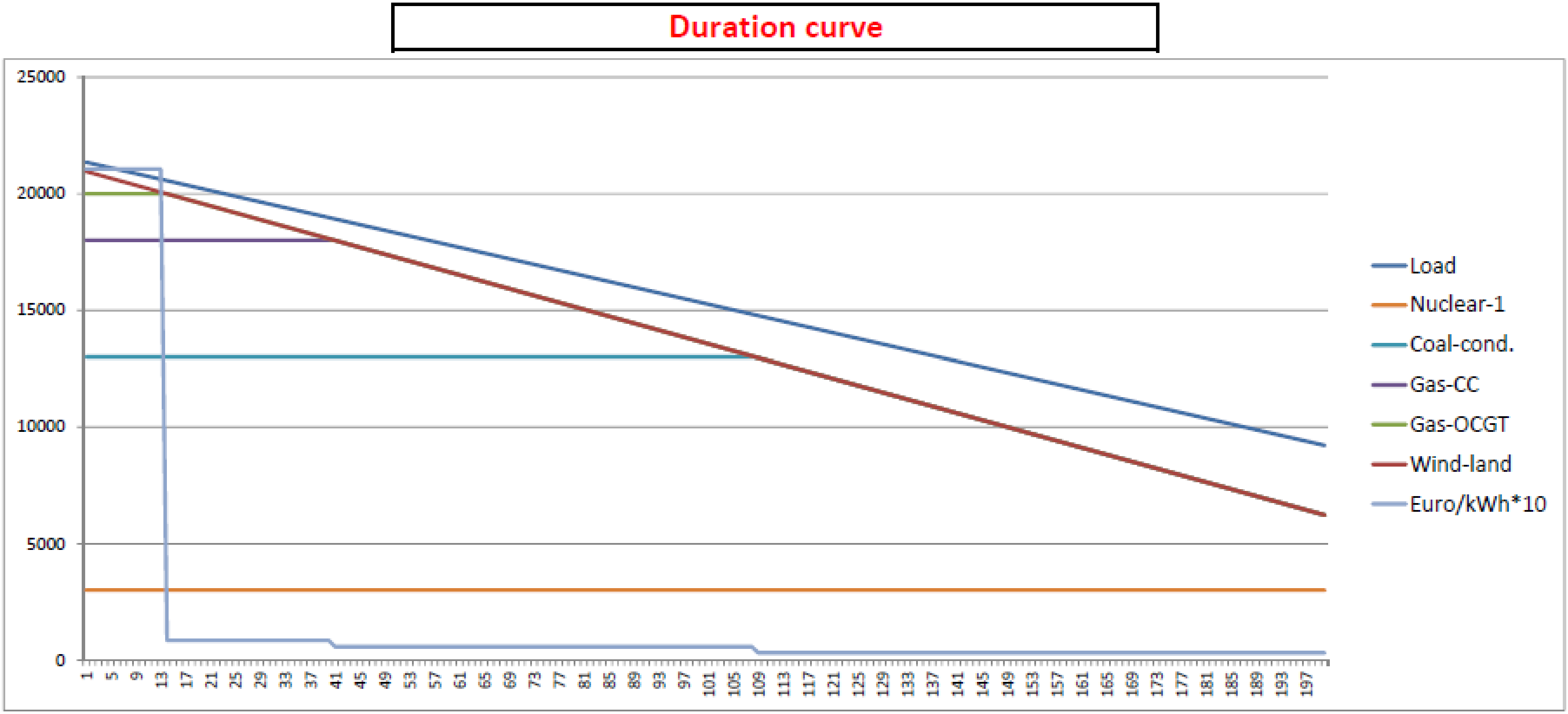
With wind power, load + 300 MW

Capacity credit of wind power

”True” value: Considers the possibility of wind power increase the reliability of the power system, ≈ 20% of installed capacity.

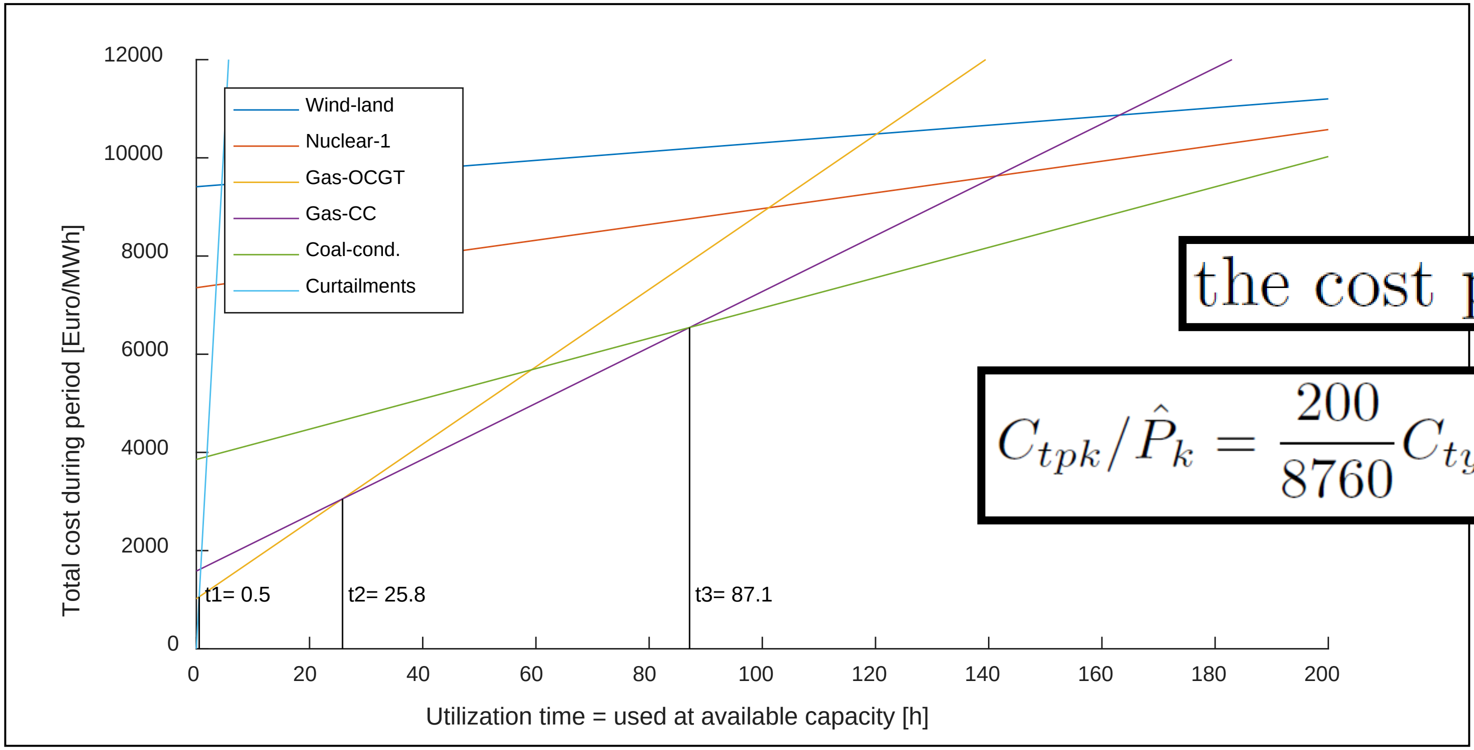
Market value: High market prices when there is a risk for power deficit.

Linearized system calculations



$$LDC_{example-3.2}(t) = 21360 - (t-1) \cdot 61 \text{ MWh/h}$$
$$NLDC_{example-3.2}(t) = 20960 - (t-1) \cdot 74 \text{ MWh/h}$$

Linearized system calculations
Cost minimization



the cost per MW:

$$C_{tpk}/\hat{P}_k = \frac{200}{8760}C_{tyk} + C_{Wk} \cdot T_{pk}$$

$$\begin{aligned} C_{tpk}/\hat{P}_k &= C_{tpj}/\hat{P}_j = \frac{200}{8760}C_{tyk} + C_{Wk} \cdot T_{jk} = \frac{200}{8760}C_{tyj} + C_{Wj} \cdot T_{jk} \\ &\Rightarrow \\ T_{jk} &= \frac{200}{8760}\frac{C_{tyk} - C_{tyj}}{C_{Wj} - C_{Wk}} \end{aligned}$$

Linearized system examples

This example is based on the linearized demand and wind power from previous example. There are then two cases:

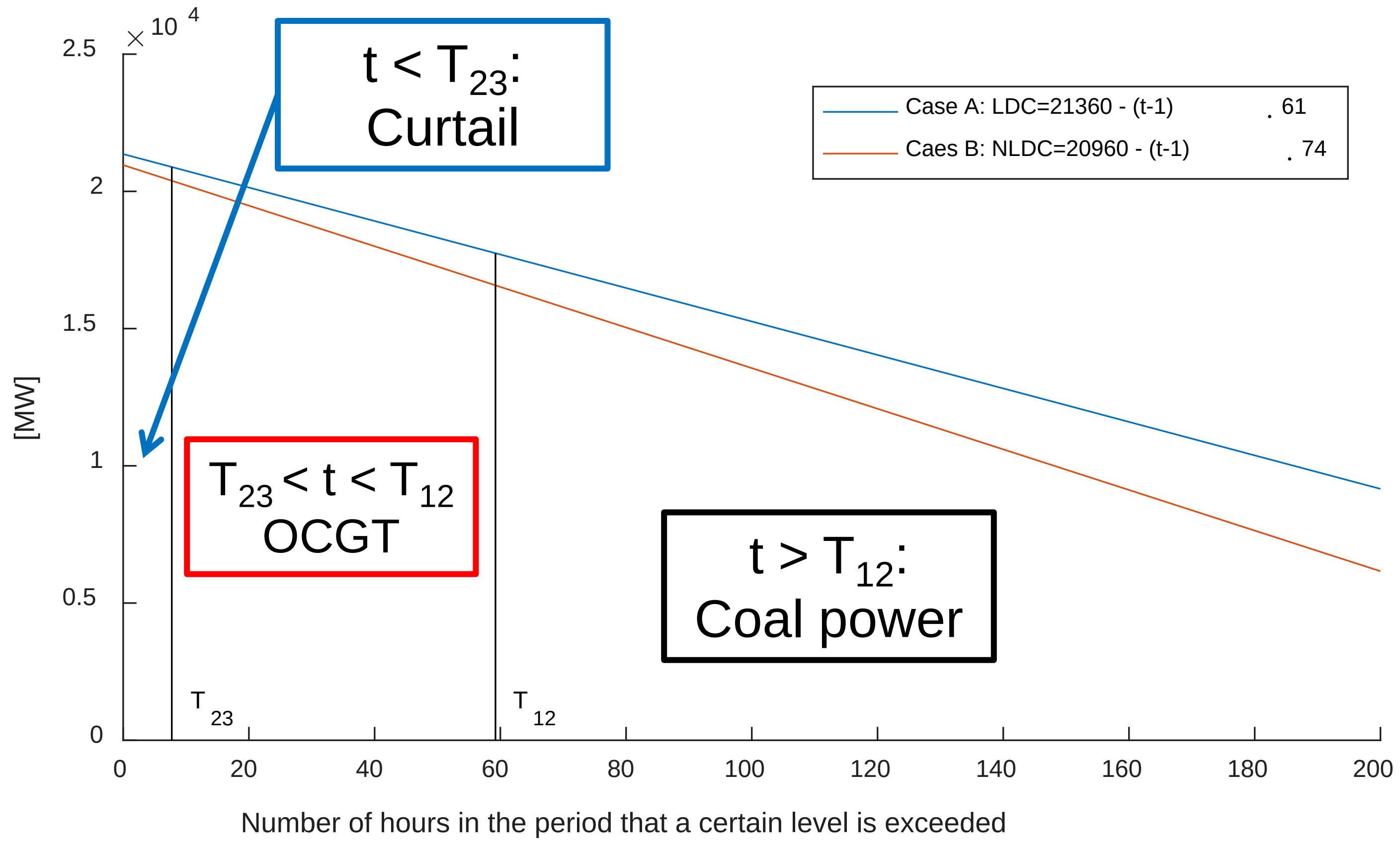
A. no wind power and
B. with wind power.

In this simplified example there are two other sources: Coal power and OCGT. And if the sources do not produce enough, then there will be curtailments. The curtailment costs are here, for illustrative reasons, decreased with a factor of 10. The costs of the different sources are then

Nr	Source	C_{tyk} [Euro/MW/period]	C_{wk} [Euro/MWh]	E_{k-CO2} [ton/MWh]	T_{kj} [h]
1	Coal	3855.9	30.85	0.71	59.23
2	OCGT	1019.6	78.74	0.51	7.74
3	Curtailments	0	210.53	-	-

Linearized system examples

Demand and optimal utilization times:



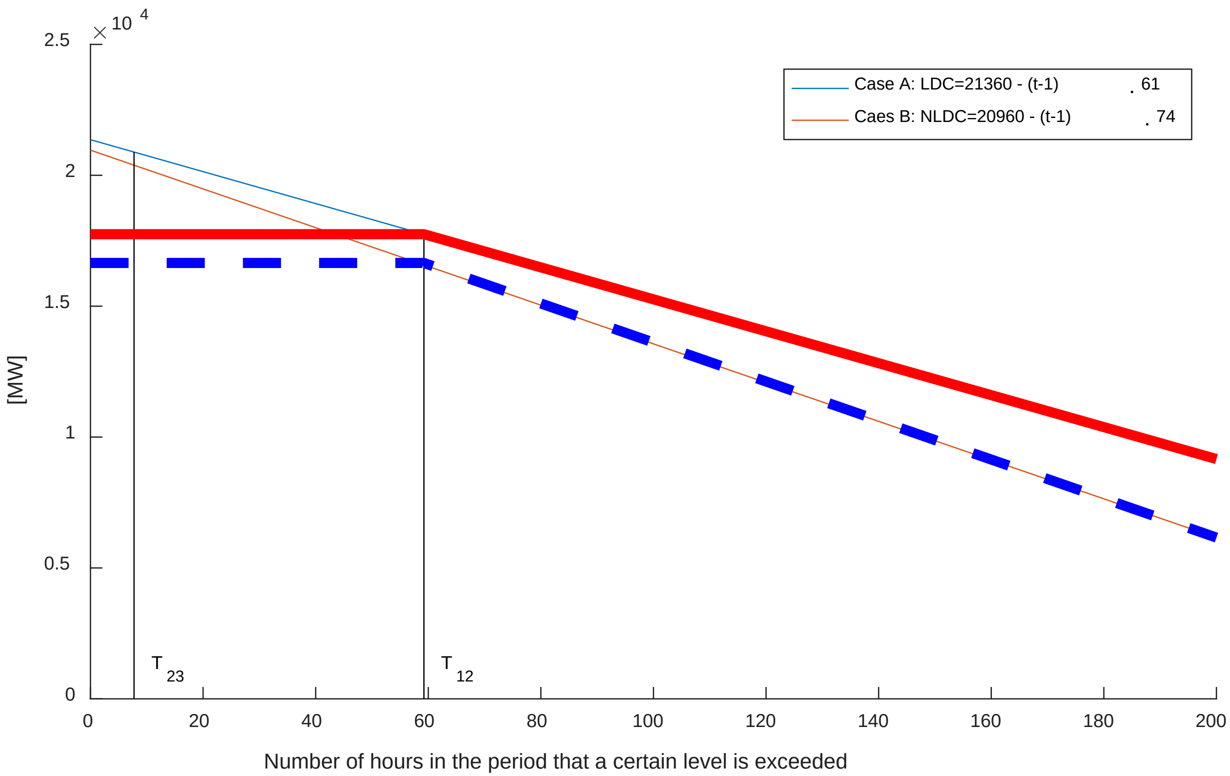
$$
\begin{aligned}
LDC_{example-3.2}(t) &= 21360-(t-1)\cdot 61 \text{ MWh/h} \\
NLDC_{example-3.2}(t) &= 20960-(t-1)\cdot 74 \text{ MWh/h}
\end{aligned}
$$

Linearized system examples

a) Assume a cost minimizing approach for both case A and case B. What is the difference in LOLP?
b) What is the change in coal power and energy production when moving from case A to case B.
c) How much will the CO_2 emission change from case A to case B assuming cost minimization
d) Assume a requirement of LOLP is maximum 0.1 %. Which is then the needed price for the last OCGT in order to get this in case B.
e) Assume a requirement of LOLP is maximum 0.1\%. Which is then the needed capacity payment for OCGT in order to get this in case B and not allowing higher prices than during curtailments, i.e., 210.53 Euro/MWh

Linearized system examples

b) What is the change in coal power and energy production when moving from case A to case B. Energy calculation for coal power.



Linearized system examples: a)

a) Assume a cost minimizing approach for both case A and case B. What is the difference in LOLP?

a) The LOLP corresponds to the number of curtailment hours. This is for both cases = T_{23}= 7.74 hours, corresponding to 7.74/200=3.87 %.

Linearized system examples: b)

b) What is the change in coal power and energy production when moving from case A to case B.

The amount of coal power can be identified from the known utilization time which is at least 59.23 hours. For case A this correponds to loads below $21360 - 58.23 \cdot 61$=17750 MW and for case B it corresponds to $20960 - 58.23 \cdot 74$=16651 MW. The decrease in coal power is then 1099 MW. The energy production is shown in figure 8. The energy production is then calculated as the corresponding area, i.e., a sum of one triangle and two rectangles:

$$
\begin{aligned}
Min_{LDC} &= 21360 - 199 \cdot 61 = 9221 \text{ MW} \\
Min_{NLDC} &= 20960 - 199 \cdot 74 = 6234 \text{ MW} \\
W_{coal}(A) &= 59.23 \cdot 17750 + (200 - 59.23) \cdot 9221 + \frac{1}{2}(200 - 59.23) \cdot 9221 = 2949.7 \text{ GWh} \\
W_{coal}(B) &= 59.23 \cdot 16651 + (200 - 59.23) \cdot 6234 + \frac{1}{2}(200 - 59.23) \cdot 6234 = 2597.0 \text{ GWh}
\end{aligned}
$$

Linearized system examples: c)

c) How much will the CO2 emission change from case A to case B assuming cost minimization

First the energy production in the OCGT has to be calculated. This is done in the corresponding way as for the coal power, i.e., the area between the corresponding curve for OCGT and the one for coal power:

$$\begin{aligned}
MW_{OCGT}(A) &= 21360 - 7.74 \cdot 61 - 17750 = 3192.3 \text{ MW} \\
MW_{OCGT}(B) &= 20960 - 7.74 \cdot 74 - 16651 = 3810.2 \text{ MW} \\
W_{OCGT}(A) &= 7.74 \cdot 3192.3 + \frac{1}{2}(59.23 - 7.74) \cdot 3192.3 = 106.88 \text{ GWh} \\
W_{OCGT}(B) &= 7.74 \cdot 3810.2 + \frac{1}{2}(200 - 59.23) \cdot 3810.2 = 127.57 \text{ GWh}
\end{aligned}$$

What is shown here is that the amount of both capacity and energy production, in the OCGT:s, is increased when a system with wind power and minium costs is designed. Coal power is decreased with 1099 MW while OCGT increases with 618 MW. Changes of CO2 emissions now become

$$\begin{aligned}
CO2(A) &= 2949.7 \cdot 10^3 \cdot 0.71 + 106.88 \cdot 10^3 \cdot 0.51 = 2.149 \text{ Mton CO2} \\
CO2(B) &= 2597.0 \cdot 10^3 \cdot 0.71 + 127.57 \cdot 10^3 \cdot 0.51 = 1.909 \text{ Mton CO2} \\
CO2(A) - CO2(B) &= 0.240 \text{ Mton CO2}
\end{aligned}$$

which then means a decrease of $0.240/2.149 = 11$ %. From the calculations in example 3.2 this is then a result of introducing 338700 MWh in a system with a total demand of 3058100 MWh, i.e., 11 %.

Linearized system examples: d)

d) Assume a requirement of LOLP is maximum 0.1 %. Which is then the needed price for the last OCGT in order to get this in case B.

The aim is a requirement of LOLP is maximum 0.1% and we evaluate this for case B. In the "cost minimizing case" we have curtailments during 7.74 hours out of 200, i.e., an LOLP of 3.87 %. An LOLP of 0.1% corresponds to $0.001 \cdot 200 = 0.2$ hours during this week. The cost for the last MW of OCGT is then the sum of the investment cost for 200 hours but only paid during the 0.2 hours of use, plus the operating cost. The price must then be on this level in order to finance the last MW:

$$\text{Needed price} = \frac{1019.6}{0.2} + 78.74 = 5097.8 + 78.74 = 5176.5 \text{ Euro/MWh}$$

Linearized system examples: e)

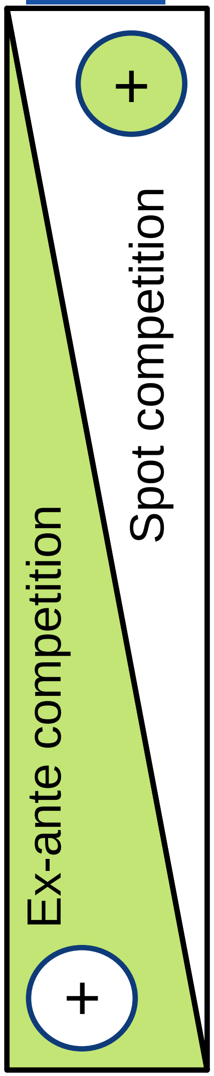
e) Assume a requirement of LOLP is maximum 0.1\%. Which is then the needed capacity payment for OCGT in order to get this in case B and not allowing higher prices than during curtailments, i.e., 210.53 Euro/MWh

The last MW of OCGT is only used during the 0.2 hours with curtailments and the price is then 210.53 Euro/MWh. The income during these 0.2 hours is then $0.2 \cdot 210.53 = 42.11$ Euro. The operation cost during the 0.2 hours is $0.2 \cdot 78.74 = 15.75$ Euro. This means that the last MW of capacity is paid with 42.11-15.75= 26.36 Euro. But the cost for the last MW is 1019.6 Euro. So the capacity payment must be 1019.6-26.36=993.2 Euro/MW.

EG2220: Power Generation, Environment and Markets – Adequacy challenge – capacity markets

Lennart Söder
Professor in Electric Power Systems, KTH

Four different market designs studied within Eurelectric



Market	Renewables	Capacity
1) Energy-only market	• No support for mature technology	• Energy-only market for existing and new capacity
2) Decentraliz-ed certificate	• Certificates that retailers have to purchase	• Capacity certificate that the retailers have to purchase
3) Central auctions	• Central auctions of renewables with additionsl income from the market	• Central capacity auctions with additional income from the market
4) Full payment auctions	• Central auctions of full payment (Some CfD models) • No market price risk	• Central auctions with full payment (Some CfD models) • No market price risk

Three challenges at large amount of variable renewables (solar/wind)

C1: Handling of the continuous balance.

C2: **Low wind and solar power production and high power consumption. This issue is called ”capacity adequacy issue”.**

C3: High wind and solar power production and low power consumption.

Lennarts view: Solve **C2** and **C3** ➔ needed resources. Then probably there is enough resources to handle **C1**

Who will invest in peak power plants?

Lennart Söder
Professor in Electric Power Systems

Who will invest in peak power plants? (= the last plant used….)

The investment:

- must be profitable
- with assumption of perfect competition this means that

Σ(power price – operation cost) > investment cost

Concerning ”capacity markets”

To obtain a good system adequacy, a capacity market can be created. If there is no specific capacity market, then this is

1) **Energy-Only Market**

There are different types of capacity markets including

2) Long-Term Contracts or Options for energy,
3) Payment Mechanisms for Capacity,
4) Quantity Requirements for Capacity, and
5) Demand Curves for Capacity
6) Strategic Reserves (= Sweden)

About new nuclear power in UK

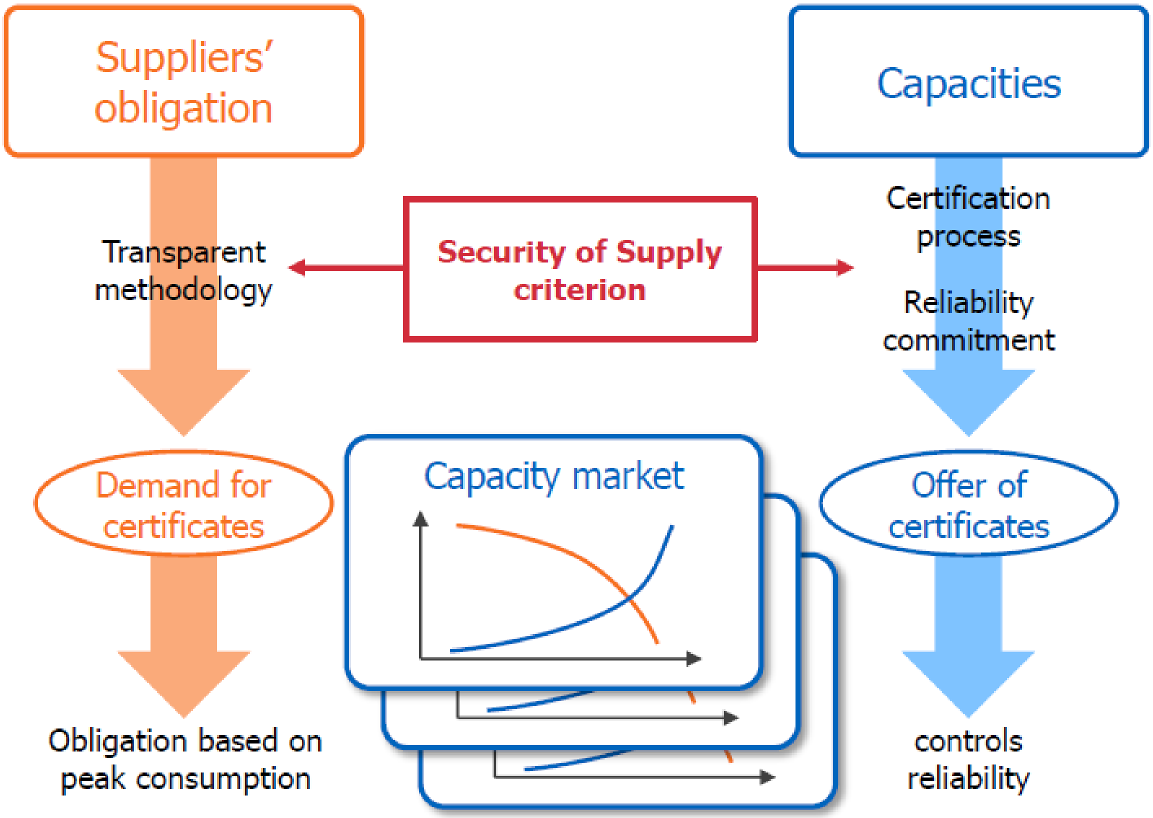
- The UK Government and EDF Group have reached commercial agreement on the key terms of a proposed investment contract for the Hinkley Point C nuclear power station in Somerset.
- The key terms include a “Strike Price” of £89.50 /MWh fully indexed to the Consumer Price Index (= 124.520 EUR = 1,154.65 SEK)
- https://www.gov.uk/government/news/initial-agreement-reached-on-new-nuclear-power-station-at-hinkley

French capacity mechanism in a nutshell

Security of supply criterion
defined by the Minister of Energy
(loss of load expectation = 3h)

Obligation carried by suppliers
to acquire enough capacity certificates to meet the peak consumption of their clients

Capacity operators' **commitment**
to make their capacities available during consumption peaks. In compensation, they are granted certificates that they will be able to sell to suppliers



The price of capacity reveals the value of Security of Supply.
The price drops to zero if there is no risk on Security of Supply.

Sweden: Background to the ”strategic reserve”

- Sweden has a winter peak load which is not so common, since it requires low temperature in whole Sweden at the same time
- For this issue Sweden has a legislation concerning ”strategic reserve”. Originally 2000 MW was purchased for each winter in a tendering process with a certain share from consumption side.
- The current legislation states that this should be taken away until 2020. This winter 1500 MW was purshased
- There is a discussion concerning how to manage this in future, especially with larger amounts of wind power replacing dismantled nuclear power (2020-2025)

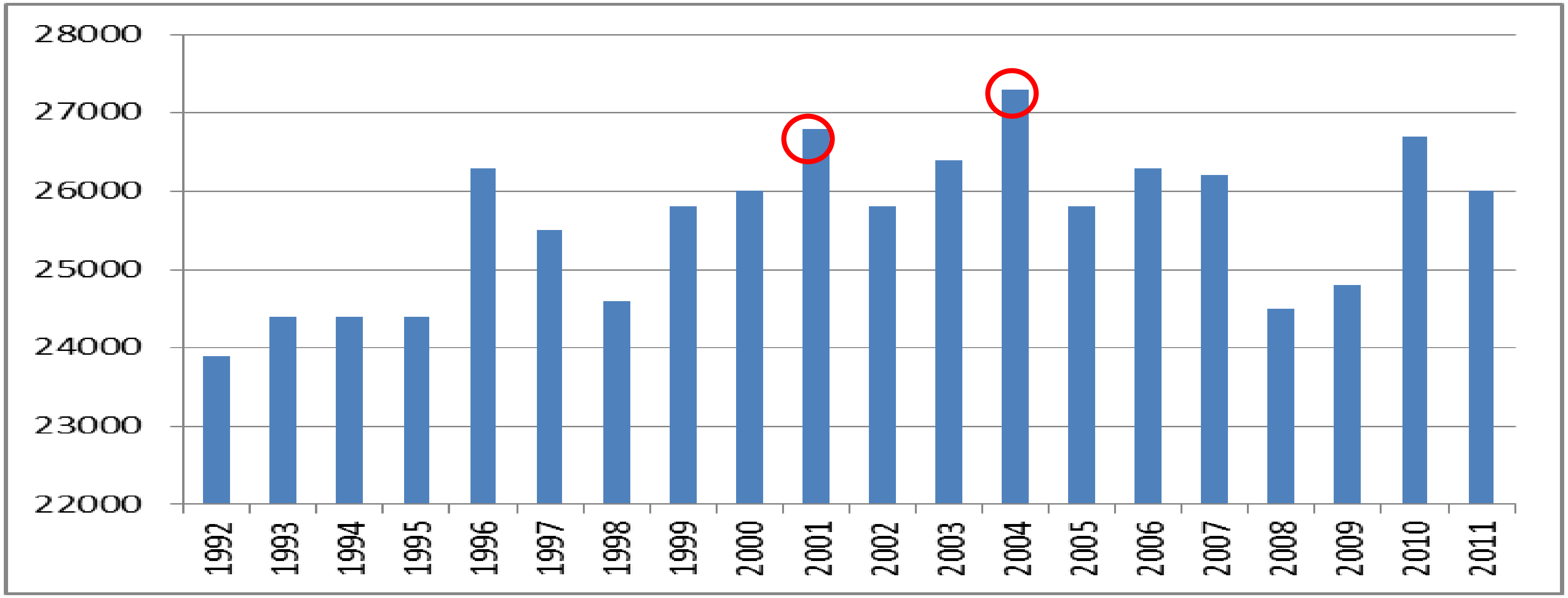
Reserves in Sweden 2014-15
Consumers accepted to reduce consumption

Company	Area	MW
AB Sandvik Materials Technology	SE3	22
AV Reserveffekt AB 1	SE4	9
AV Reserveffekt AB 2	SE3	24
AV Reserveffekt AB 3	SE4	12
AV Reserveffekt AB 4	SE3	7
AV Reserveffekt AB 5	SE3	25
Göteborg Energi DinEl AB	SE3	25
Vattenfall AB 1	SE3	50

Company	Area	MW
Vattenfall AB 2	SE3	30
Ineos AB	SE3	30
Rottneros Bruk AB	SE3	27
Storaenso AB	SE3, SE4	230
Holmens Bruk AB	SE3	100
Modity Energy Trading AB	SE3	17
Befesa Scandust AB	SE4	18
Sum:		**626 MW**

Swedish load peaks 1992-2011

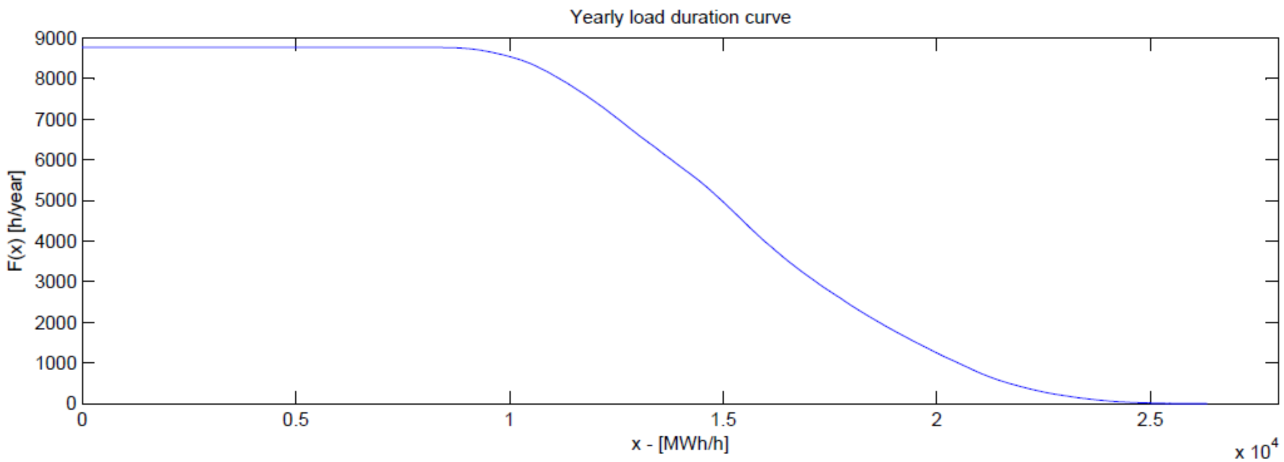
MWh / h



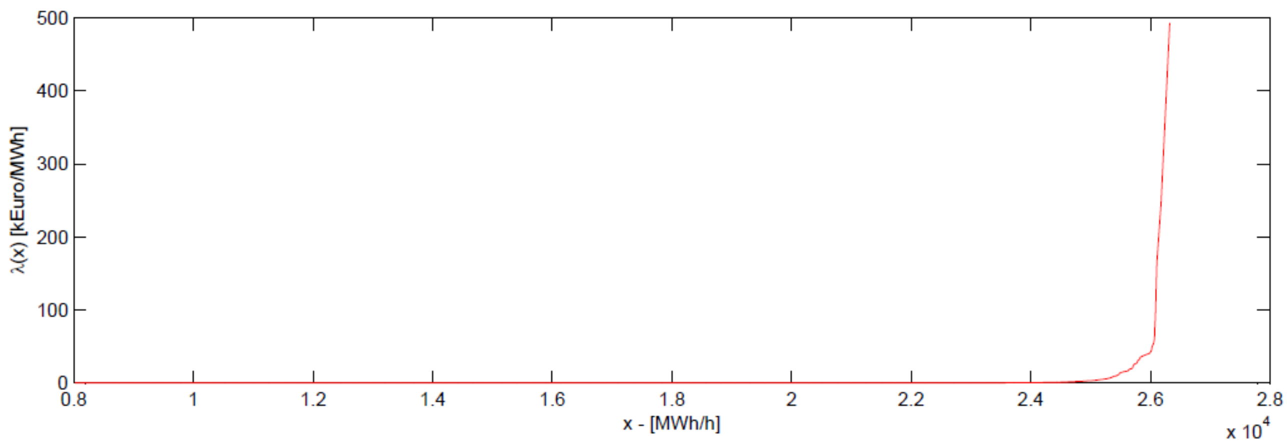
- The last 500 MW was only used 1 yearr out of 20
- Will the ”market” take the risk to provide reserves which is only used some hours in one year out of 20?

Basic set-up / assumption

- For peaks the most suitable production is OCGT. Other technologies (DSM) have to be more cost effective

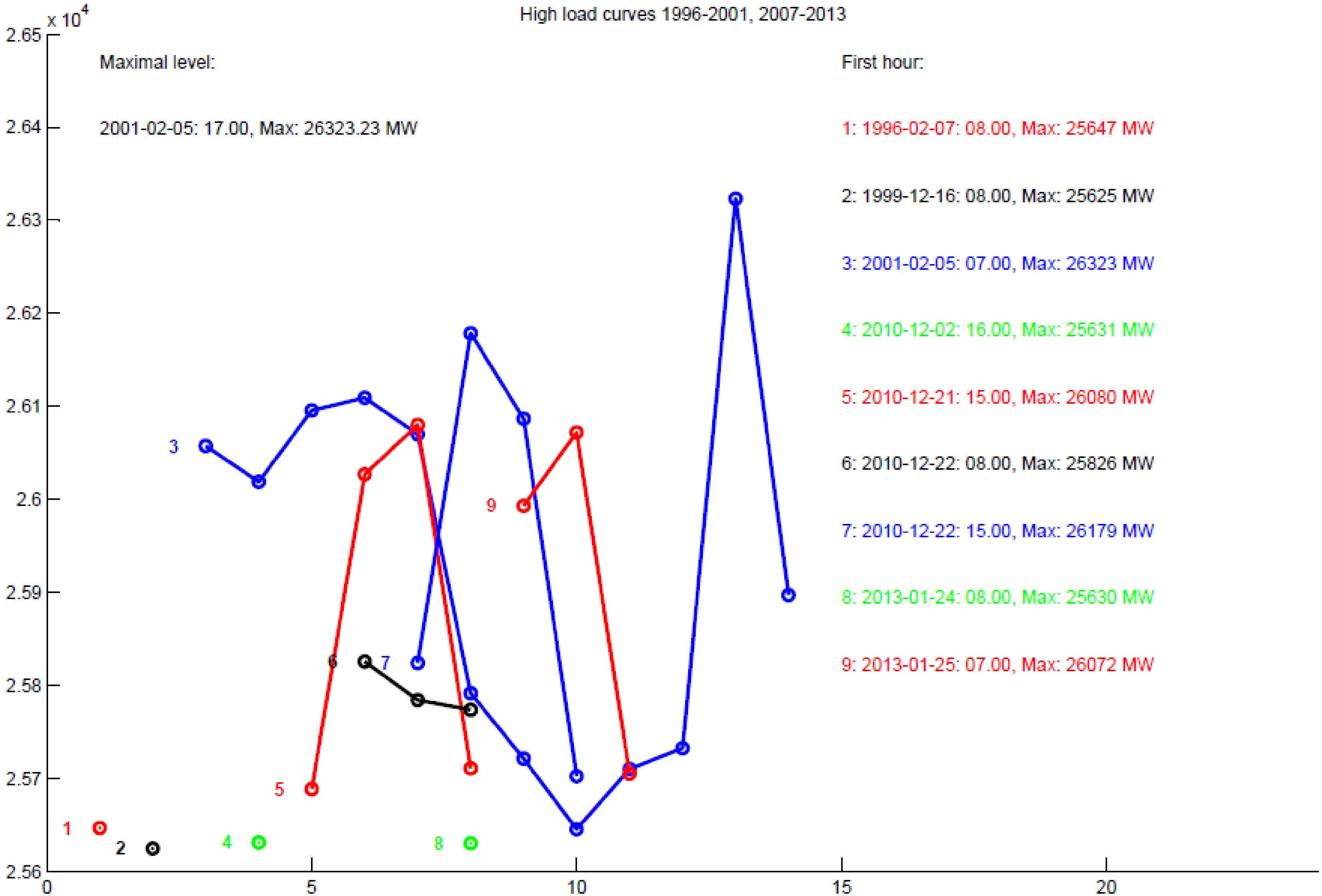


LDC



Required price to make OCGT profitable

High loads in Sweden 1996-2001, 2007-2013



Details of needed prices for rarely used OCGT:s

x - load level MW	$F(x)$ - duration h/year	$\lambda(x)$ - needed price kEuro/MWh=Euro/kWh
>23000	191.3	>0.32
>23500	118.1	>0.44
>24000	62.6	>0.73
>24500	29.3	>1.41
>25000	11.6	>3.38
>25500	2.7	>14.20
>26000	0.85	>44.9
>26250	0.08	>492.75

LDC

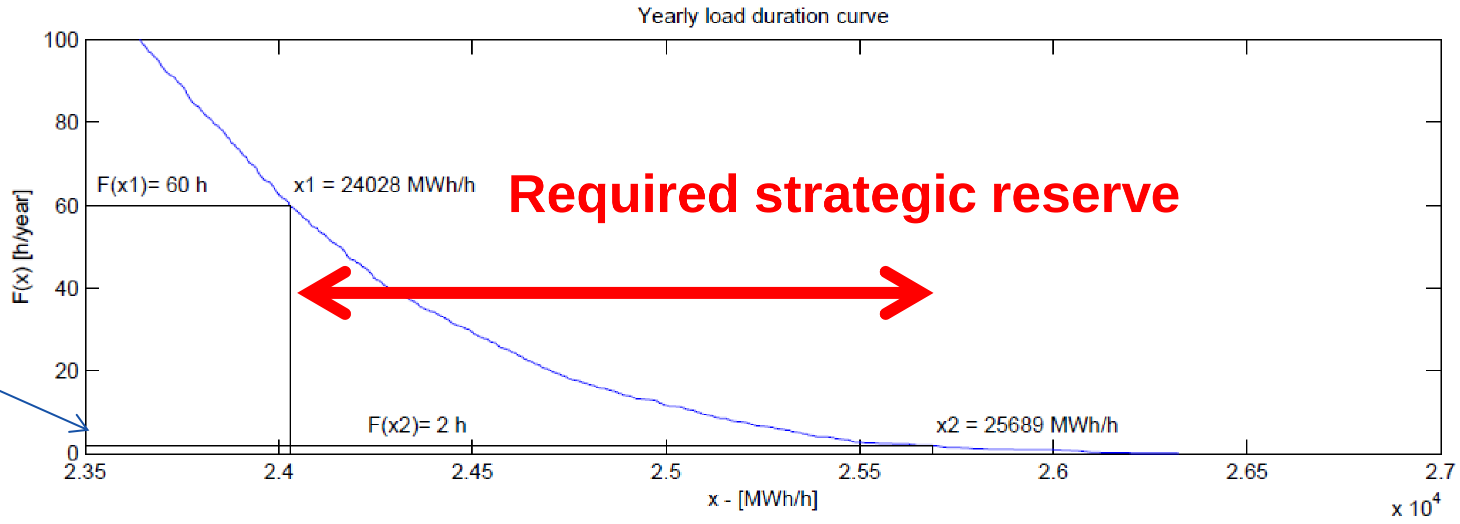
Required price to make OCGT profitable

Basic principles

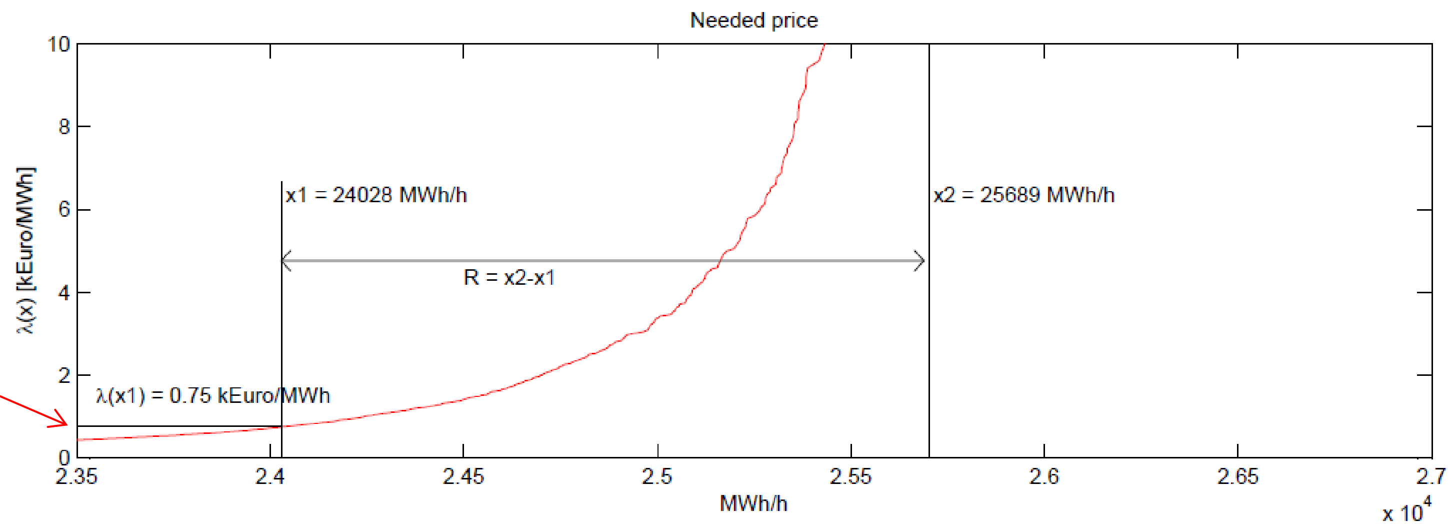
- One can **accept these high prices**. Challenges include, e.g. strategic behaviour since producers may earn a large amount during these hour. Benefit of high prices is incentive for DSM. How to finance DSM if prices are never high?
- But still there is a limit, so what is **the accepted LOLP**?
- If these prices are not accepted, then rarely used units have to get a payment, no matter the production ➔ **capacity market / strategic reserve**.
- **LOLP, max price and amount of reserve strongly related**
- What is wind power impact on these issues?

Basic set-up / assumption

Accepted LOLP



Accepted max price



Different tests for Sweden

- Sweden isolated
- OCGT:s used for peaks
- Period 1996-2001 + 2005-2013 used bacause of good wind data. First period: 50 wind sites – 4 GW, second period: scaled real production to 4 GW.
- **Four cases studied**:
  - Base case
  - Change caused by 9 TWh wind power,
  - Change caused by 9 TWh nuclear, with 2 units including simulated outages, p=90%
  - Change caused by 9 TWh scaled real nuclear production, (**2001-2013**)

Different tests for Sweden - 1

LOLP = 1h in 5 years, max price 1,4 Euro/kWh

Example	Power/energy from studied alternativ	Other market invest-ment, [MW]	Extra reserve [MW]	Market+ extra reserve	Reduced need of capacity = capacity value
Only load	-	24497	1681	26178	-
With wind power	4000 MW, 9 TWh	23717	2018	25735	**443 MW**
With 2 nuclear station	1346 MW, 9 TWh	23338	1941	25279	**899 MW**

Different tests for Sweden - 2

LOLP = 1h in 10 years, max price 3 Euro/kWh

Example	Power/energy from studied alternativ	Other market invest-ment, [MW]	Extra reserve [MW]	Market+ extra reserve	Reduced need of capacity = capacity value
Only load	-	24936	1387	26323	-
With wind power	4000 MW, 9 TWh	24127	1683	25810	**513 MW**
With 2 nuclear station	1346 MW, 9 TWh	23807	1735	25542	**781 MW**

Different tests for Sweden - 3

LOLP = 1h in 5 years, max price 1,4 Euro/kWh

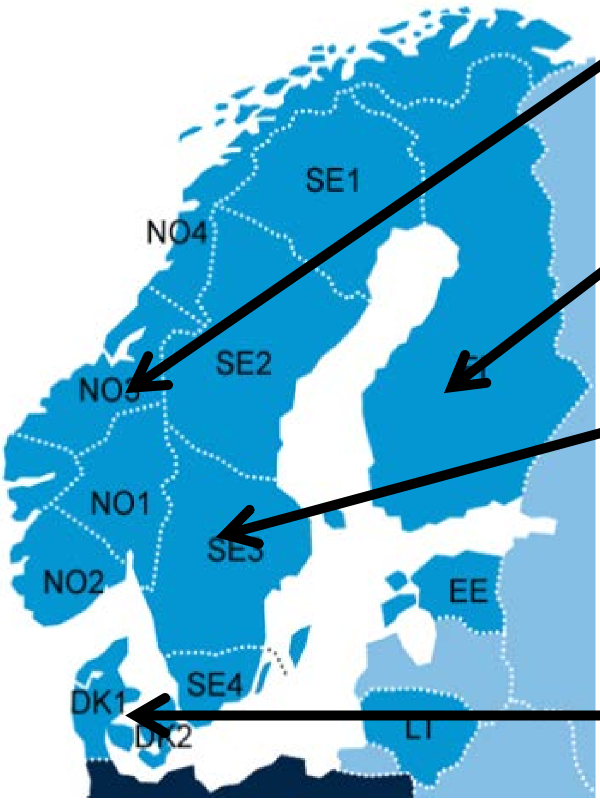
Example	Power/energy from studied alternativ	Other market invest-ment, [MW]	Extra reserve [MW]	Market+ extra reserve	Reduced need of capacity = capacity value
Only load 96-01 and 07-13	-	24497	1681	26178	-
Only load 2001-2013	-	24650	1912	26561	-
With nuclear 2001-2013	9 TWh	23498	1732	25231	**1330 MW**

Different tests for Sweden - 4

LOLP = 1h in 10 years, max price 3 Euro/kWh

Example	Power/energy from studied alternativ	Other market invest-ment, [MW]	Extra reserve [MW]	Market+ extra reserve	Reduced need of capacity = capacity value
Only load 96-01 and 07-13	-	24936	1387	26323	-
Only load 2001-2013	-	25089	1543	26633	-
With nuclear 2001-2013	9 TWh	23924	1379	25303	**1330 MW**

Peak capacity responsibilities



Norway: TSO-Statnet is responsible for "enough capacity"

Finland: TSO-Fingrid is NOT responsible for "enough capacity"

Sweden: TSO-Svenska Kraftnät is NOT responsible for "enough capacity". But: "up to 2000 MW"

Denmark: TSO-Energinet.dk is responsible for "enough capacity"

Peak capacity responsibilities example 1

1. Assume that there is a “capacity problem” in South Sweden and Denmark exports 1000 MW to Sweden.
2. Assume that there is an outage in Denmark so they have to decrease consumption.
3. According to EU legislation “non-discrimination” Denmark cannot prioritize Danish consumers before Swedish ones.
4. Does this has as a consequence that Denmark is also responsible for Sweden?

Peak capacity responsibilities example - 2

1. There are discussions of capacity payments to a rather large volume in UK
2. Probably this then leads to comparatively low energy prices compared to a case with no cap. payments
3. Both Norway and Denmark plan new cables to UK.
4. Does this mean that Denmark and Norway can import and only pay the energy price?

High load reserves in Sweden "Selective capacity market"

TSO responsible to purchase "**up to 2000 MW**" of "reserves" for peak load situations.

There is a bidding process where the cheapest offers are accepted.

Pricing:

The bids are placed on Nordpool spot. They are only used if all other bids are accepted.

The Net Regulation Price should not be allowed to exceed **5,000 Euro/MWh**.

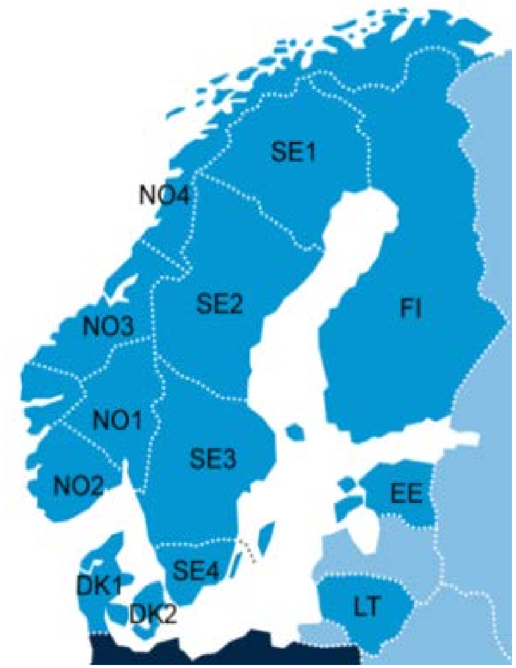
TSO can immediately impose a Disconnection Price in The event of Critical Power Shortage of 20 000 SEK/MWh ≈ **2300 Euro/MWh**

Australia: Max price 12000 AUD **≈ 9000 Euro/MWh**

Reserves in Sweden 2012-13
Consumers accepted to reduce consumption

Company	**Area**	**MW**
Stora Enso AB	3-4	210
Höganäs Sweden AB	4	25
Rottneros Bruk AB	3	27
Befesa Scandust AB	4	18
Vattenfall AB	3-4	92
Göteborg Energi AB	3	25
AV Reserveffekt	3-4	+ 67
TOTAL		**464**

Summary of (some) Nordic market challenges



Risk for prices so low so power plants cannot be financed

Large amounts of renewables ➔ often very low prices

But still other units are needed

➔ need of either (very) high prices or some kind of capacity payment mechanism.

Large amount of transmission is one part solution, but perhaps also large amounts of solar/wind power on the other end?

Price during curtailment
Lennart Söder, KTH

Pricing at peak situations

- The companies who are **balance responsible** for consumers are prepared to pay as much for purchase of power as the unbalance cost if they do not buy it.
- This means that the price on the regulating market during peak situations sets the limit.

Pricing during capacity deficit
Impossible situation

Actor retailer	Production purchase	Wanted load
A	100	100
B	200	170
C	40	100
Total	340	370

Capacity deficit
Load reduction 10 MWh/actor

Actor	Prod + load reduction	Demand	Balance
A	100+10	100	+10
B	200+10	170	+40
C	40+10	100	-50
TOT	340+30	370	0

Pricing during demand reduction

- Load reduction can be seen as a last bid to the regulating market to set the balance between production and consumption.
- The price on the regulating market is set by the last accepted bid.
- Therefore pricing of load reduction is essential
- The price of load reduction sets the interest of actors to pay for production to mitigate risk of capacity deficit
- Today (in Sweden) load reduction is not measured per actor

Continue on case studies of **new power systems**



Excel program: Set-up - 1

Future system design

		From Source data - Sweden		Parameter		Calculated				CO2: Euro/ton:	10			
Production system data				Base cost			Base cost			Operation costs				
				Interest	Euro/MW		Euro/MW	Op. Cost		Margin	Subs./ tax	CO2	Total	Op. Cost
Nr	Source	Old MW	Max MW	rate	/year	Factor	/period	Euro/MWh	Factor	Euro/MWh	Euro/MWh	Euro/MWh	Euro/MWh	order
1	Wind-land	0	15000	6%	129982	1	2967,6	8,9	1	0	0	0,00	8,9	1
4	Nuclear-1	0	15000	6%	322141	1	7354,8	16,1	1	0	0	0,00	16,1	2
6	Gas-OCGT	0	15000	6%	44656	1	1019,6	73,7	1	0	0	5,06	78,7	5
7	Gas-CC	0	15000	6%	69324	1	1582,7	53,4	1	0	0	3,49	56,9	4
9	Coal-cond.	0	20000	6%	168890	1	3855,9	23,8	1	0	0	7,10	30,9	3
12	Curtailments	0	20000	6%	0	1	0,0	2105,3	1	0	0	0,00	2105,3	6
		0						kr/MWh-el						

Base case: C-o

Production system result

Capacity		Energy		Cap. Cost	En. Cost	Tot. Cost	Revenue	Profit		Mean cost	CO2	Util. Time
MW-new	MW-tot	MWh	%	kEuro	kEuro	kEuro	kEuro	kEuro	€/MWh	Euro/MWh	tons	hours
8000	8000	504498	16,8%	23741	4514	28255	28148	-107	-0,2	56,0	0	200
3000	3000	600000	19,9%	22064	9663	31728	74010	42283	70,5	52,9	0	200
2000	2000	24684	0,8%	2039	1944	3983	34368	30385	1231,0	161,4	12485	14
5000	5000	183473	6,1%	7914	10446	18360	93034	74674	407,0	100,1	64000	76
10000	10000	1691135	56,2%	38559	52173	90733	237173	146440	86,6	53,7	1200412	200
955,8	956	4631	0,2%	0	9750	9750	9750	0	0,0	2105,3	0	8
28956	**28956**	**3008421**	**100,0%**			**182808**			**1795**		**1276898**	

Load 1 1=original, 2=simplified

Source	Factor	row	Cap. Fact	CF-org
W-land	1,507	1	0,315311194	0,315
W-sea	0,000	-	-	0,315
Solar	0,000	-	-	0,012
Period lenght [h]:		**200**	**2,4**	2,5
				0,012
				0,012

LOLP:	**4,0%**
Mean price €/MWh	**123,4**

Plot 2

1 Time curve, production/type
2 Time curve, additional production
3 Duration curve

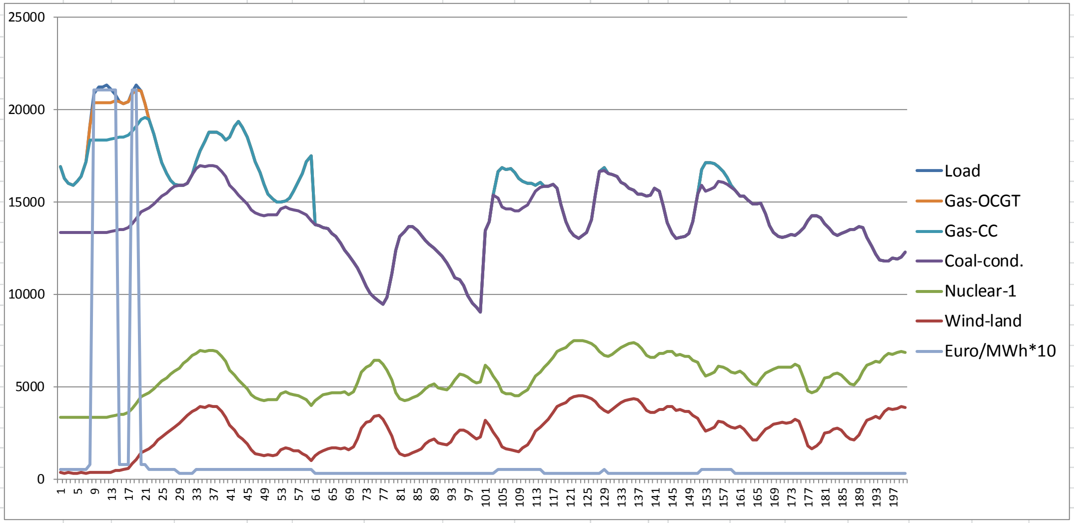
Wind 1 1=original, 2=simplified

2: Assumes that 'Wind-land' is included and has the lowest operation cost.

"Simplified" load or wind =>
Straigth lines for duration curves.

Simplified data		

Time curve, additional production



Data analysis of thermal power plants

Op. Cost	Unit	Source	Next	Min hours	Result [h]
1	1	Wind-land	-	Not thermal	200,0
2	2	Nuclear-1	5	237,3	200,0
3	5	Coal-cond.	4	87,1	200,0
4	4	Gas-CC	3	25,8	76,0
5	3	Gas-OCGT	6	0,5	14,0
6	6	Curtailments			8,0

Not thermal or more expensive than some other units

	Hour step:	1	1, 2 or 3 is possible	
Per.	Load day	Wind day	Solar day	Nr of hours
1	22	22	15	60
2	180	180	23	40
3	100	100	48	100
1	2015-01-22	2015-01-22	2015-01-15	
2	2015-06-29	2015-06-29	2015-01-23	
3	2015-04-10	2015-04-10	2015-02-17	

Excel program: Set-up – 2
Input (details in other sheet)

CO2 cost

Future system design

From Source data - Sweden	Parameter	Calculated	CO2: Euro/ton:	10

Production system data

Nr	Source	Old MW	Max MW	Interest rate	Base cost Euro/MW /year	Factor	Euro/MW /period	Base cost Op. Cost Euro/MWh	Factor	Margin Euro/MWh	Operation costs Subs./ tax Euro/MWh	Operation costs CO2 Euro/MWh	Operation costs Total Euro/MWh	Op. Cost order
7	Gas-CC	0	15000	6%	69324	1	1582,7	53,4	1	0	0	3,49	56,9	4
1	Wind-land	0	15000	6%	116824	0,9	2400,5	14,7	0,5	0	0	0,00	7,4	1
4	Nuclear-1	0	15000	6%	322141	1	7354,8	16,1	1	0	0	0,00	16,1	2
6	Gas-OCGT	0	15000	6%	44656	1	1019,6	73,7	1	0	0	5,06	78,7	5
9	Coal-cond.	0	20000	6%	168890	1	3855,9	23,8	1	0	0	7,10	30,9	3
12	Curtailments	0	20000	6%	0	1	0,0	2105,3	1	0	0	0,00	2105,3	6
		0												

Change sources

Max Capacity

Changed fixed cost

operation subsidy or tax

Existing plats

Interest rate

Changed operation cost

Extra operation margin