NTNU – Trondheim
Norwegian University of
Science and Technology

Norwegian Hydro Power as Balancing Resource for Europe

Market and Grid Impacts

TU Delft 4.Feb 2016

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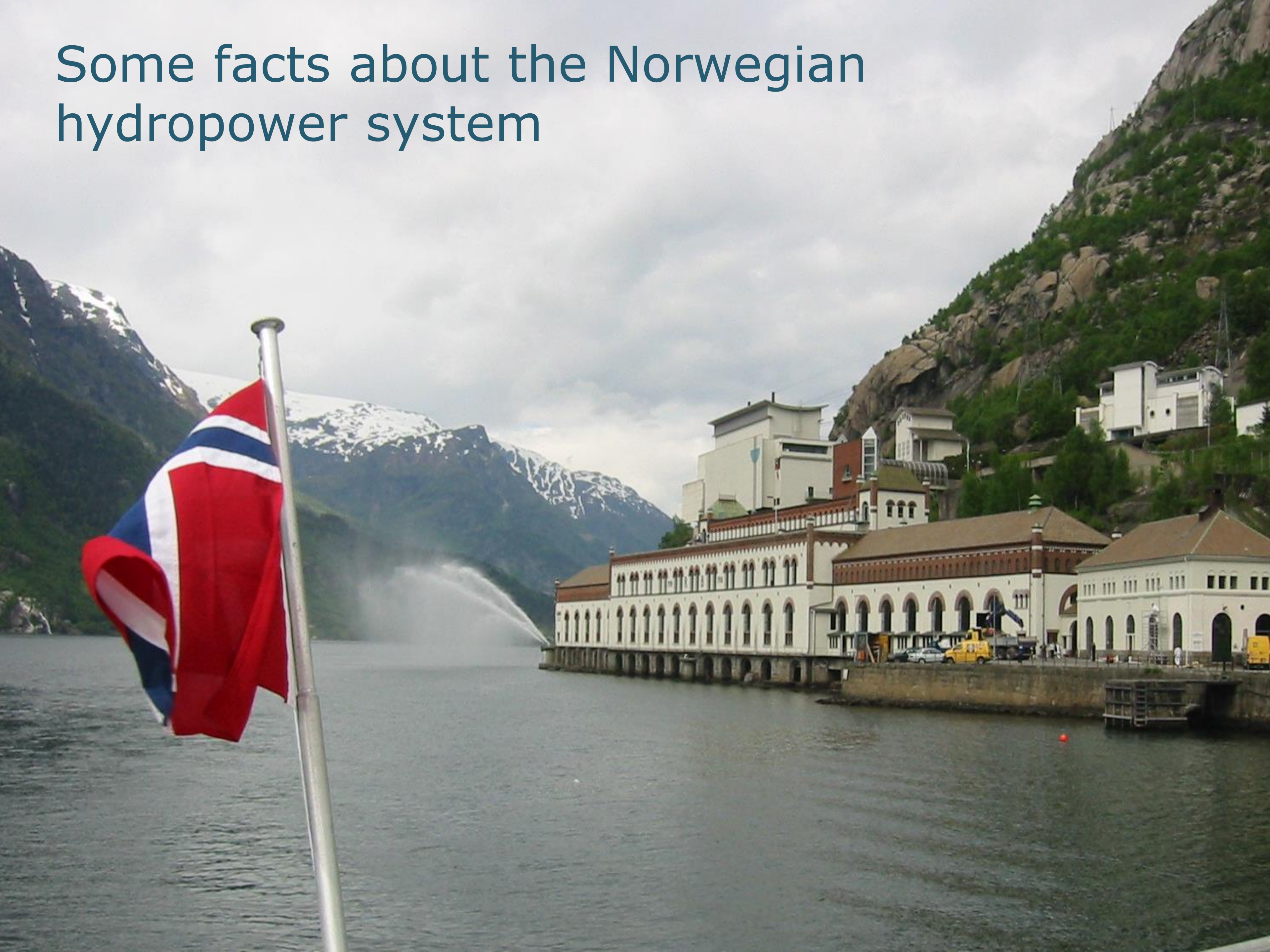
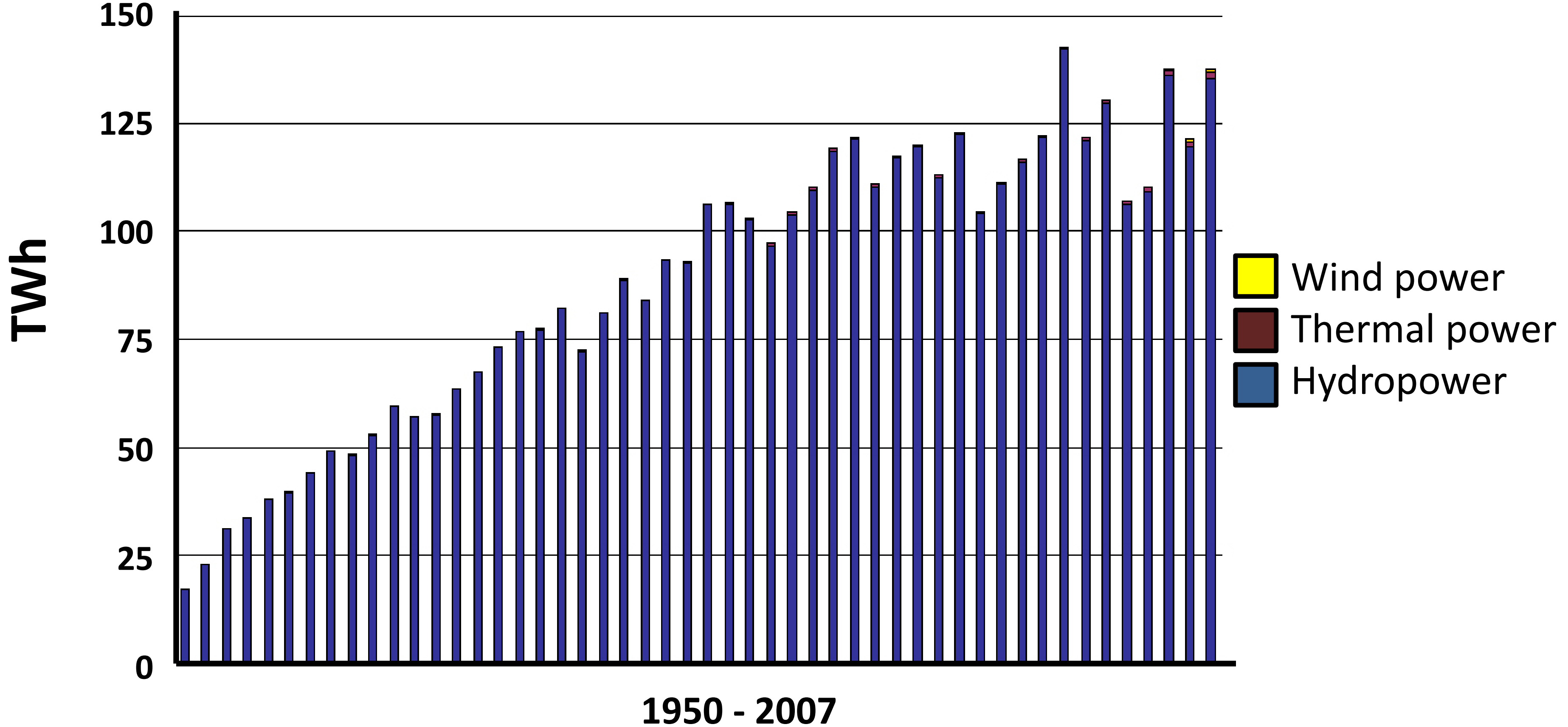
Some facts about the Norwegian hydropower system

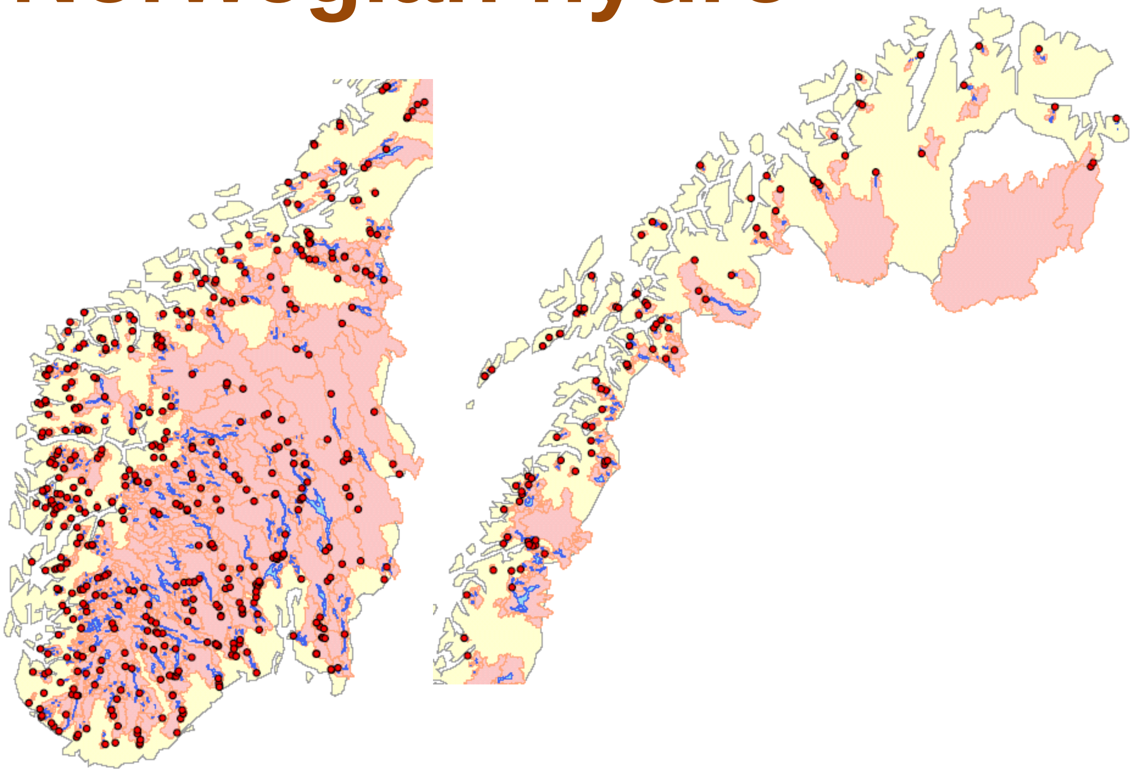


Electricity production Norway



Source: Norwegian Energy and Water Directorate

Norwegian hydro



- Hundreds of large reservoirs
- 20 reservoirs with more than 100 Mm^3 both up- and downstream

Norwegian hydropower

Natural lakes used as reservoirs

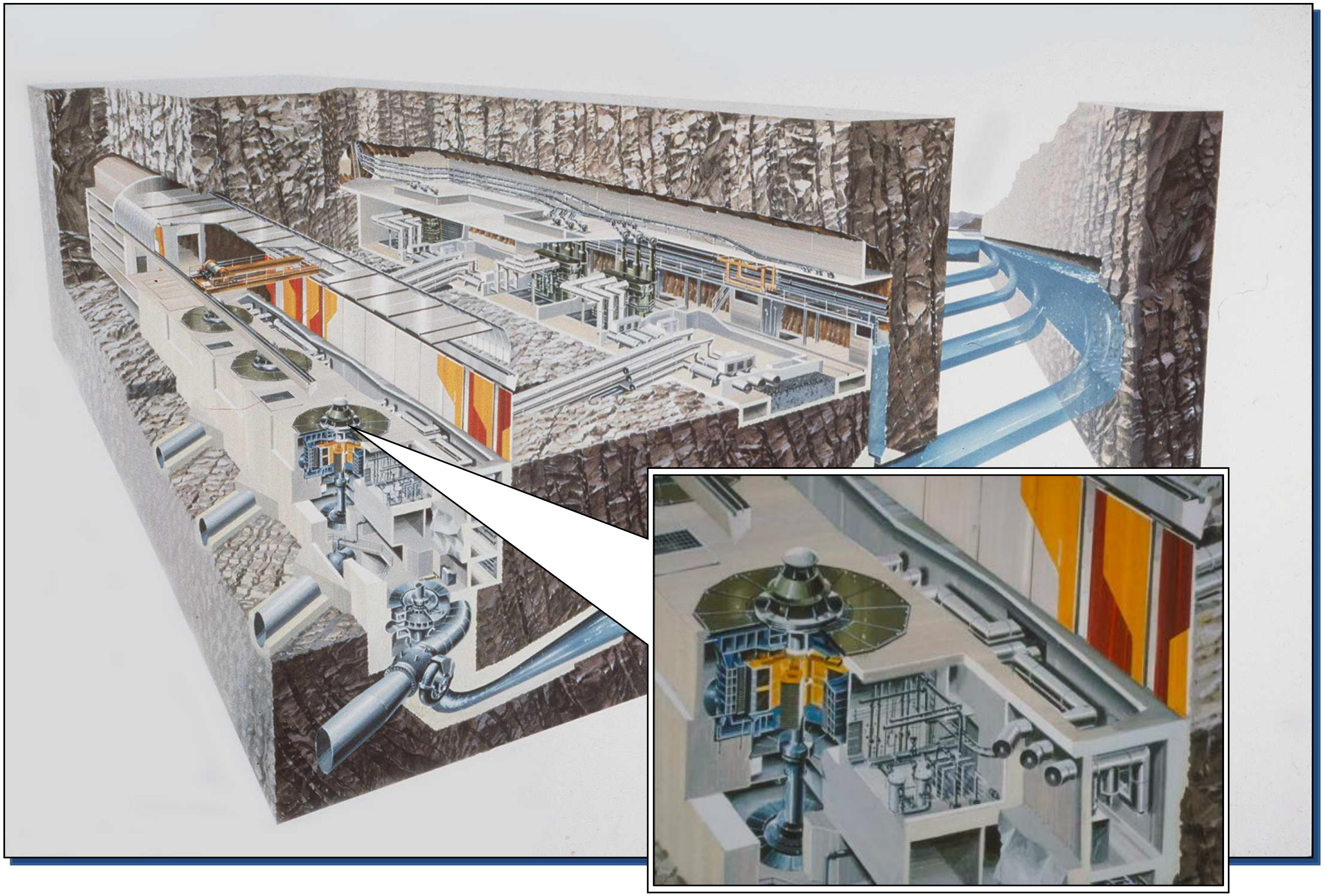
Multi-year reservoirs

Follsjø reservoir in September

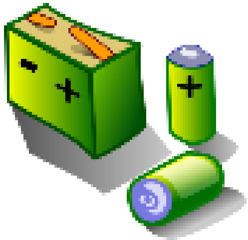
Norwegian hydropower

Solid rocks providing great opportunities to hide penstock and power plants inside the mountains

Kvilldal - Hightech Power plant
1.7 mill horse-powers(1240 MW)



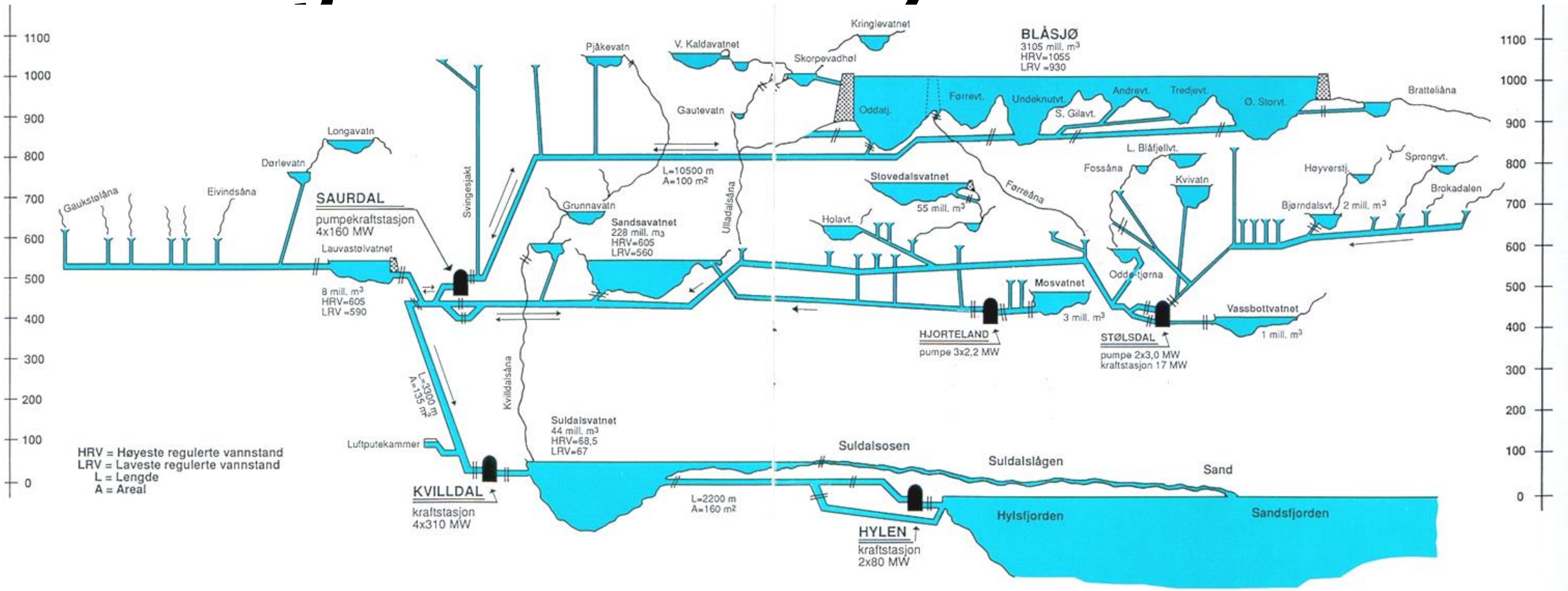
What is the value of the lake Blåsjø??



	BLÅSJØ	HOME BATTERY
Capacity (kWh)	8 000 000 000	10
Installation cost ($)	-	3,500
Lifetime (years)	∞	10

→ 8 TWh of home batteries cost 2800 Billion $

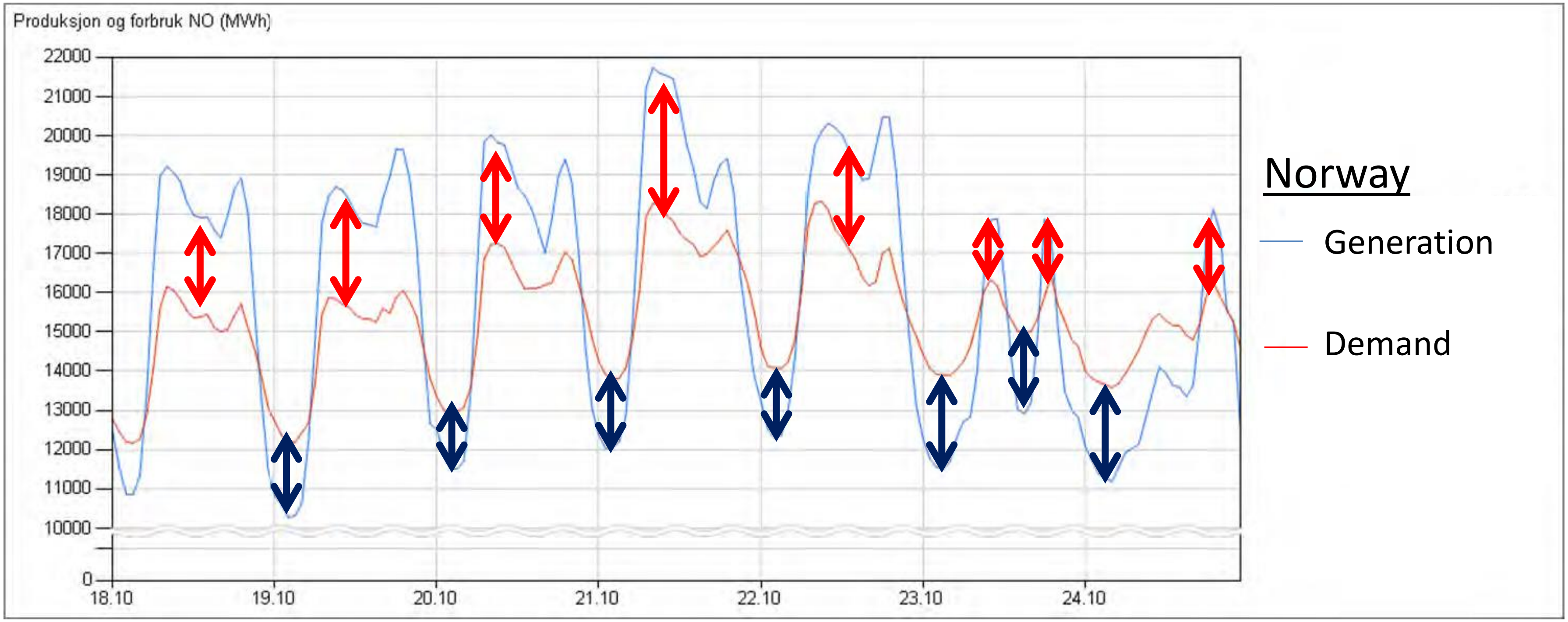
Storage and waterways



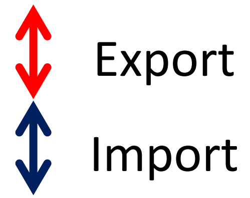
--> Complex Storage Scheme:

- 1 Major reservoir, contains water for multi year production (in case of dry year(s))
- 34 intakes of streams plus 24 smaller reservoirs that are channeled in to the system
- 3 Major Power plants (all underground), and 2 pumping stations

Indirect storage with today's system

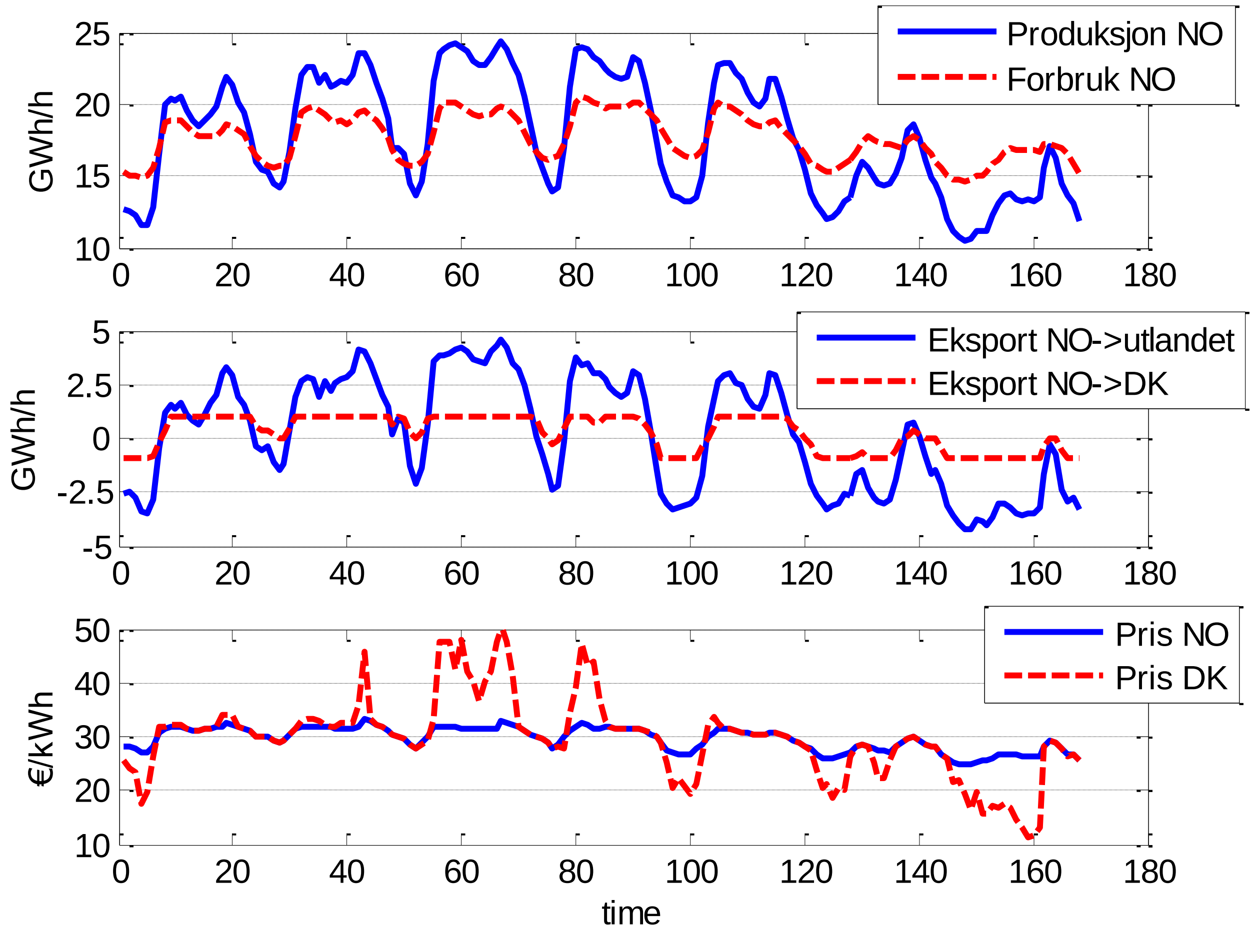


Source: Jan Hystad, Statnett

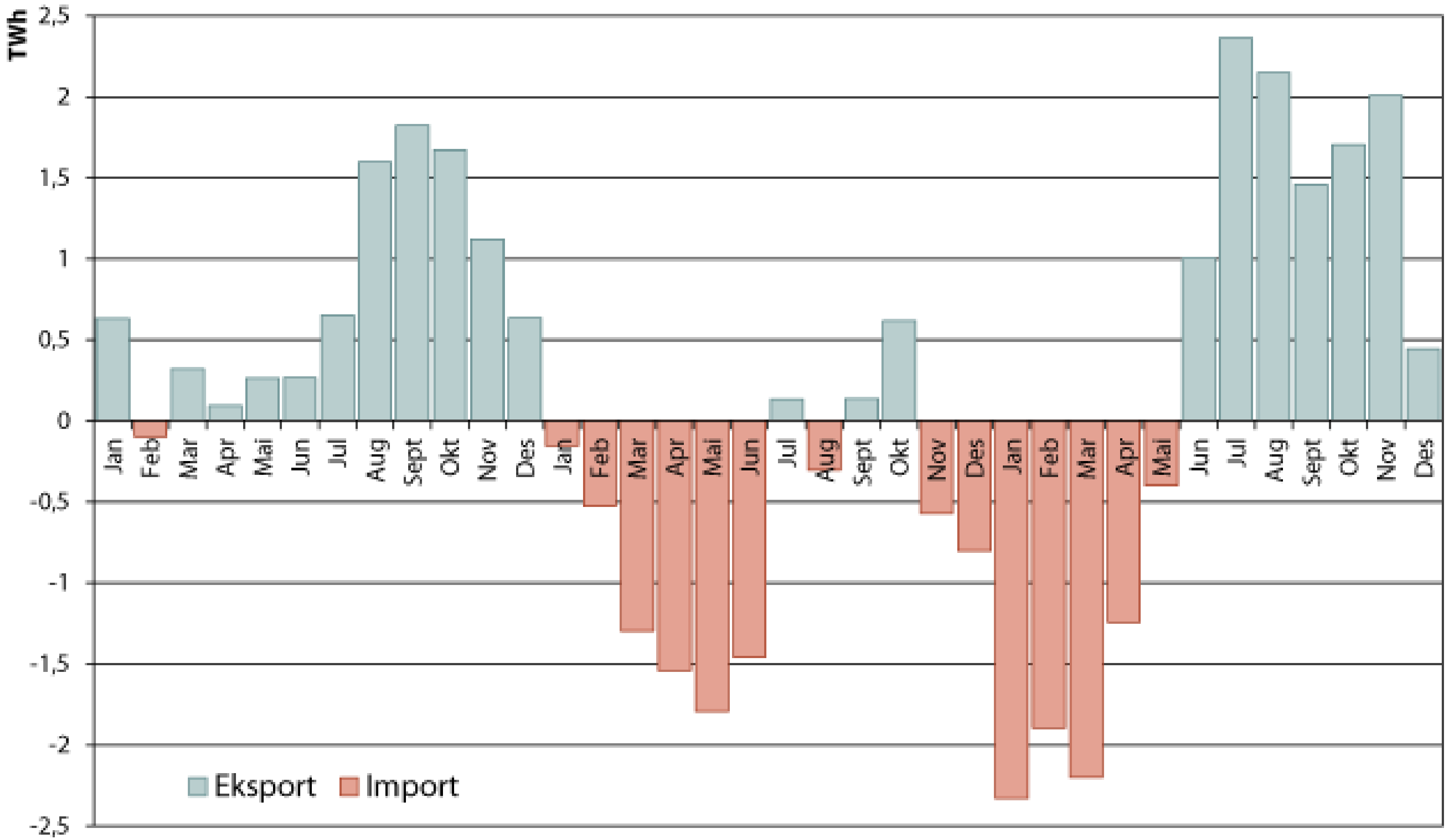


Δ Generation - Δ load :
11 500 - 6 200 = 5 300 MW of balancing

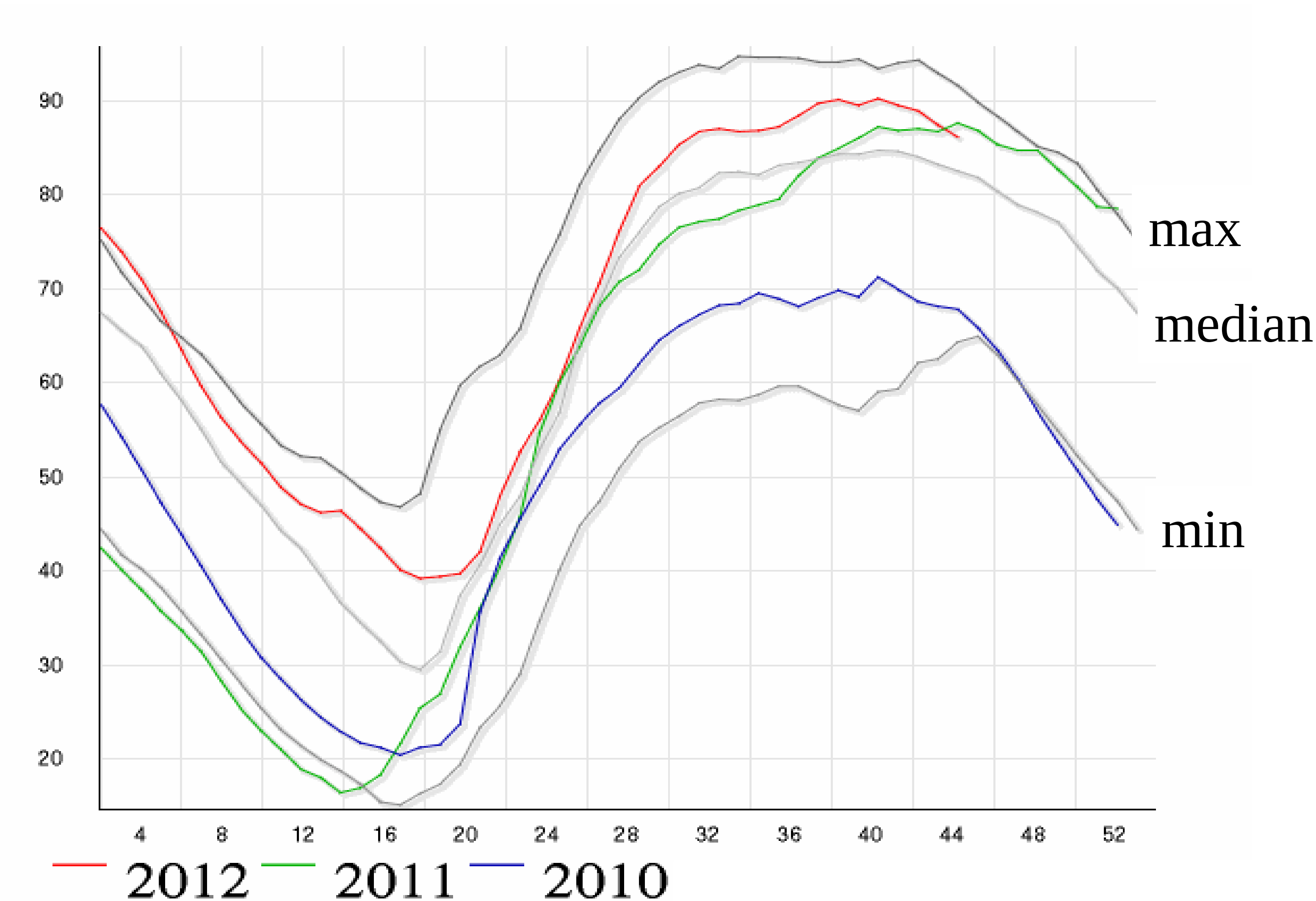
Exchange in the short-term (hours to weeks)



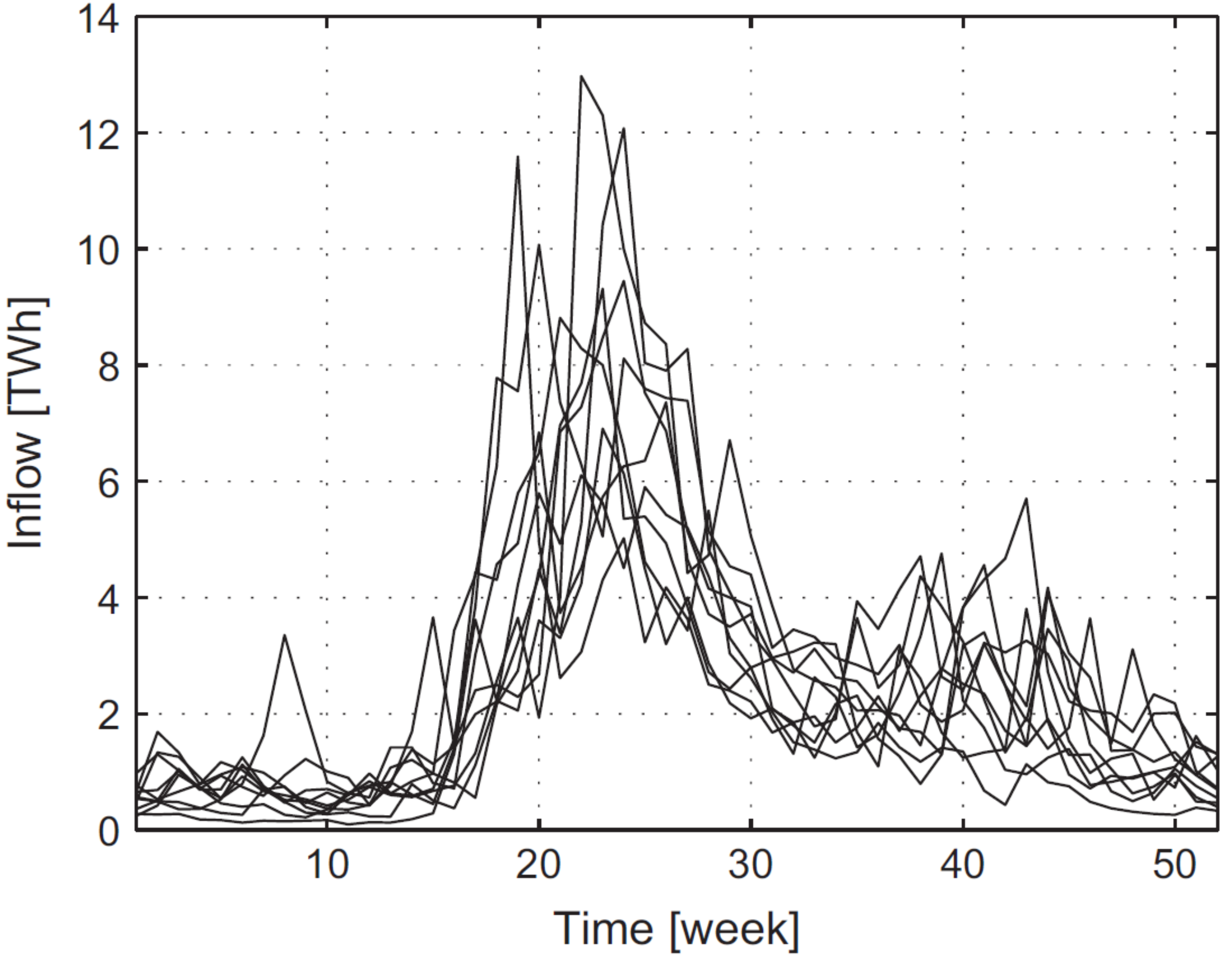
Exchange in the long term (months to years)



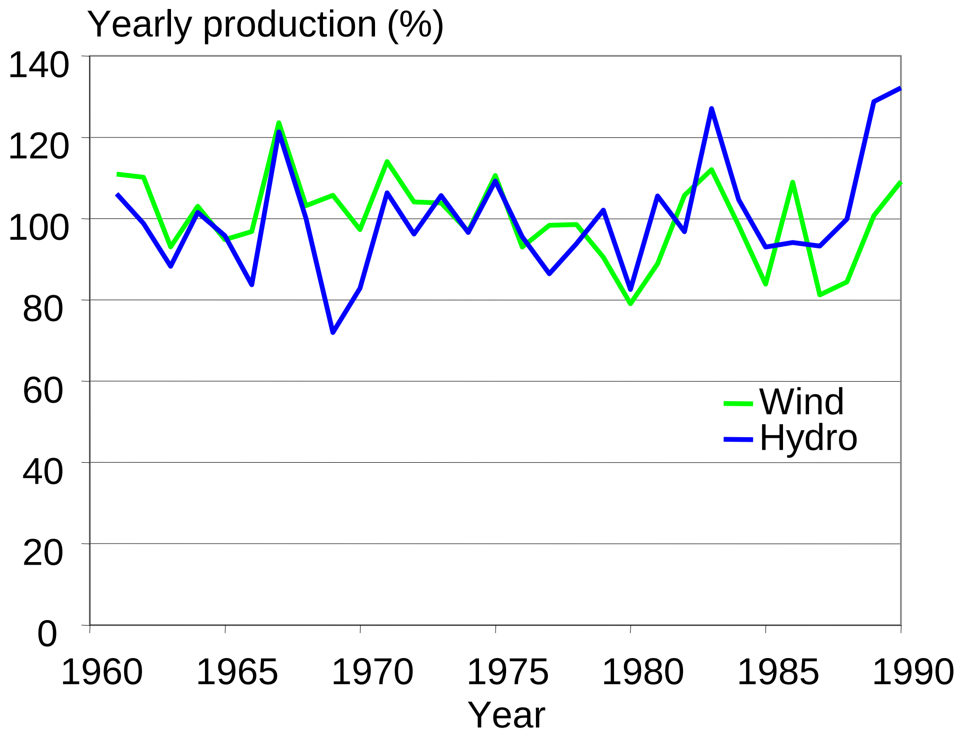
Reservoir filling (%) in Norway up to 2012

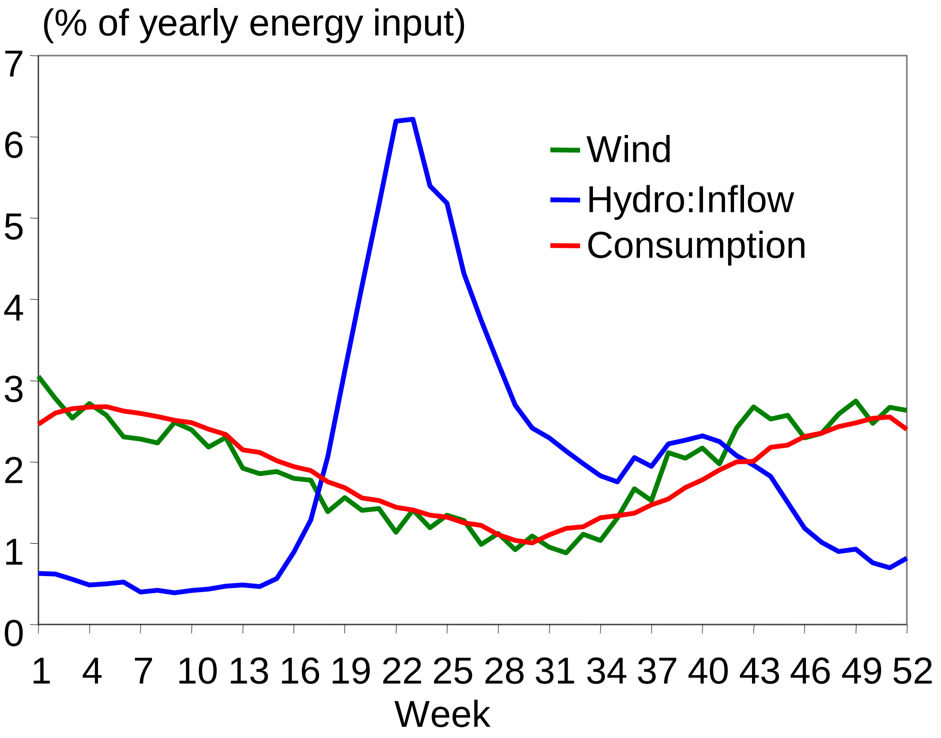


Norwegian hydro inflow for 75 years

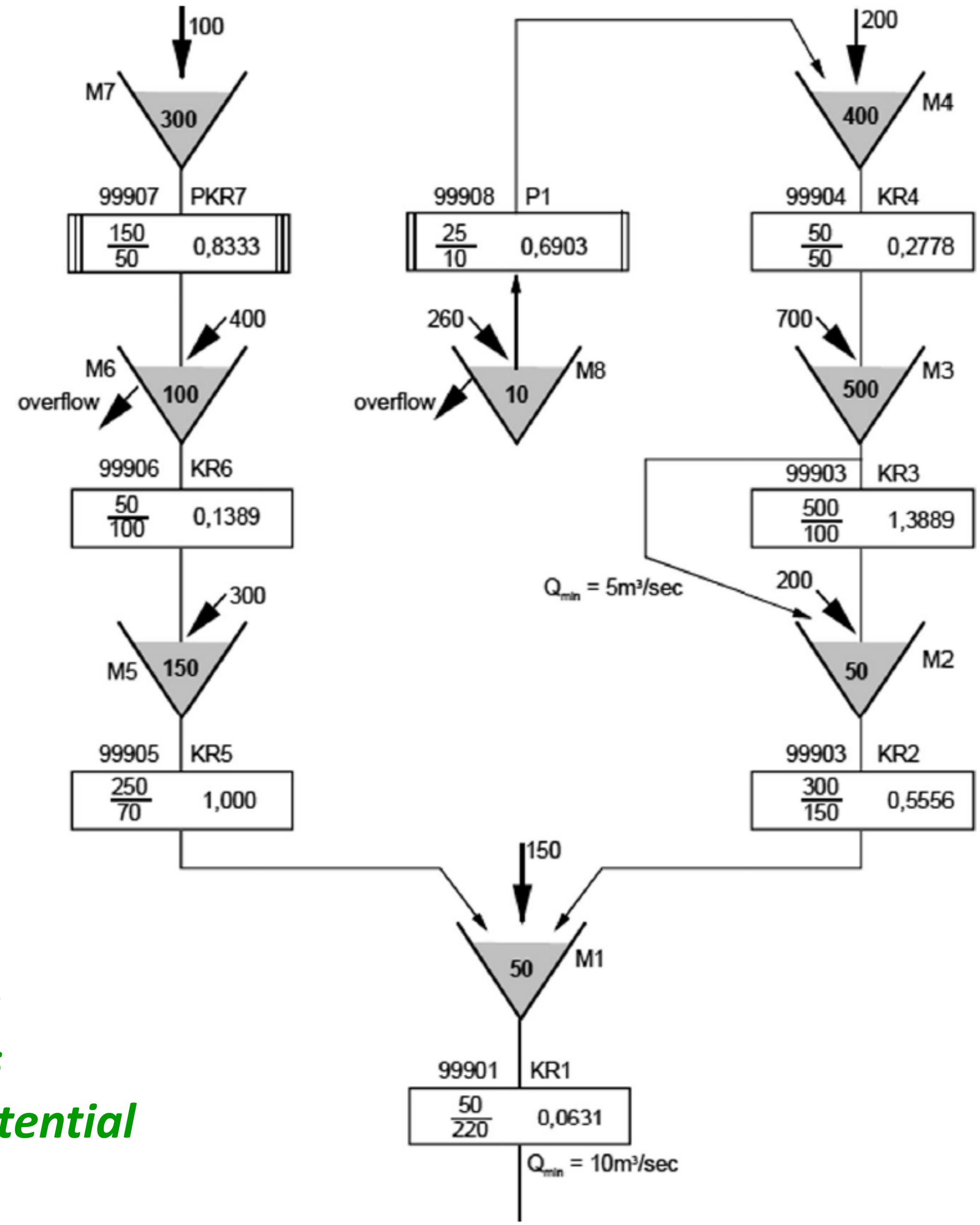


Wind power and hydro power in Norway: A good match

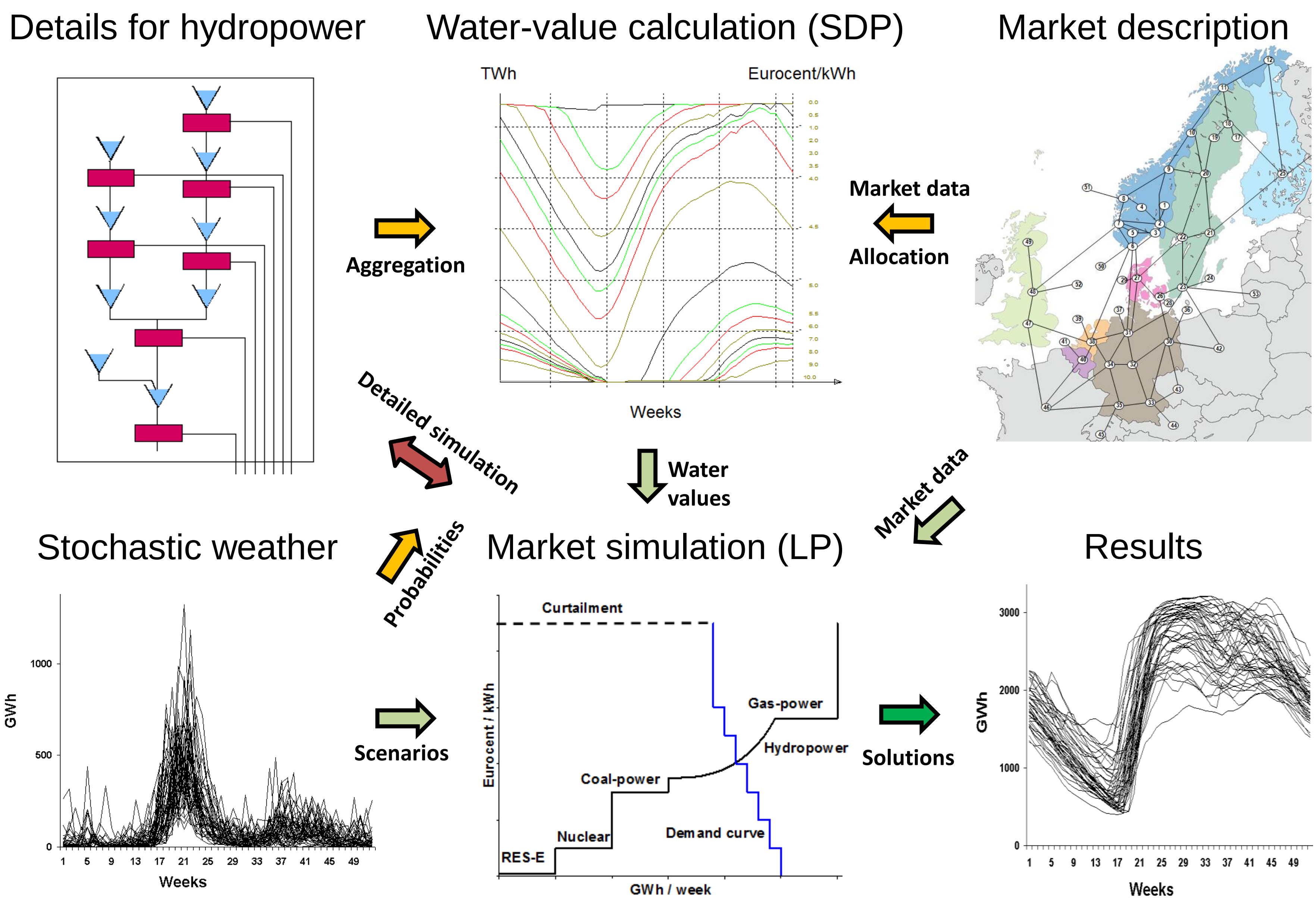




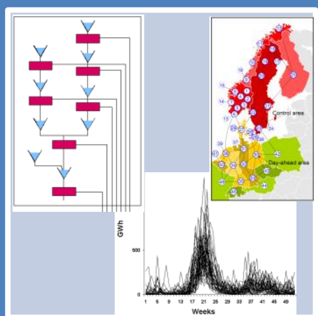
The water courses are complex



Detailed modelling is required to capture the hydro characterisitcs and thus the «green battery» potential

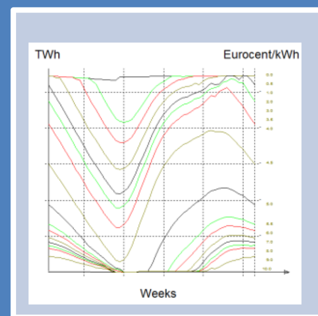

Details for hydropower
Water-value calculation (SDP)
Market description
TWh
Eurocent/kWh
Weeks
Aggregation
Market data
Allocation
Detailed simulation
Water values
Market data
Probabilities
Stochastic weather
Market simulation (LP)
Results
GWh
1000
500
0
1 5 9 13 17 21 25 29 33 37 41 45 49
Weeks
Scenarios
Curtailment
Eurocent / kWh
Gas-power
Hydropower
Coal-power
Nuclear
Demand curve
RES-E
GWh / week
Solutions
GWh
3000
2000
1000
0
1 5 9 13 17 21 25 29 33 37 41 45 49
Weeks

EMPS – Day-ahead spot market



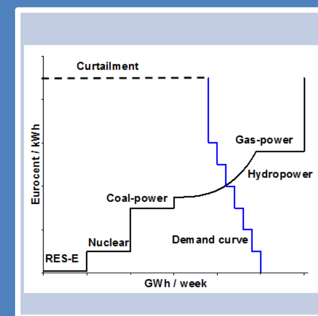
Input

- Market description
- Detailed hydro model
- Stochastic climatic years



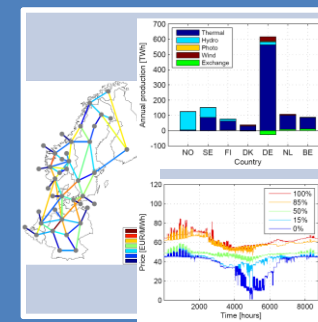
Strategy phase

- Aggregated model
- Water value calculation (Stochastic Dynamic Programming)



Simulation phase

- Detailed model
- Power market simulation (Linear Programming)



Results

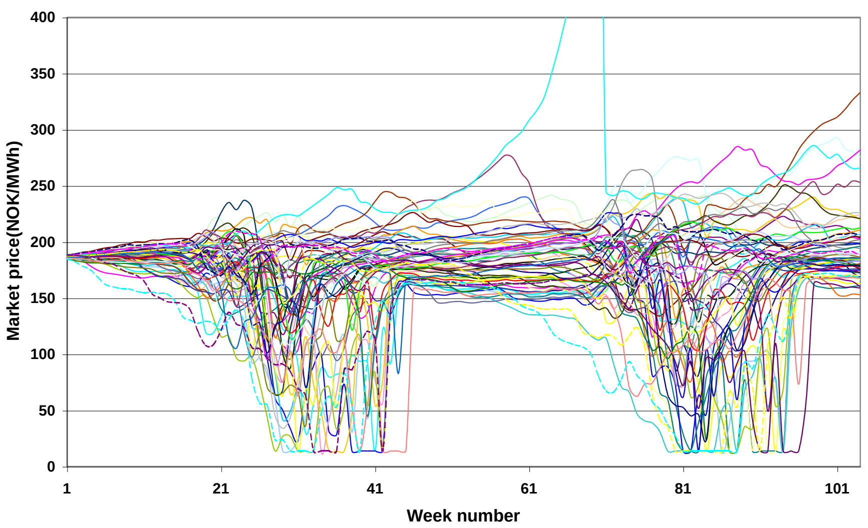
- Generation and transmission dispatch
- Area prices

O. Wolfgang et al. "Hydro reservoir handling before and after deregulation", Energy, Vol. 34, pp.1642-1651, 2009

Available results from EMPS

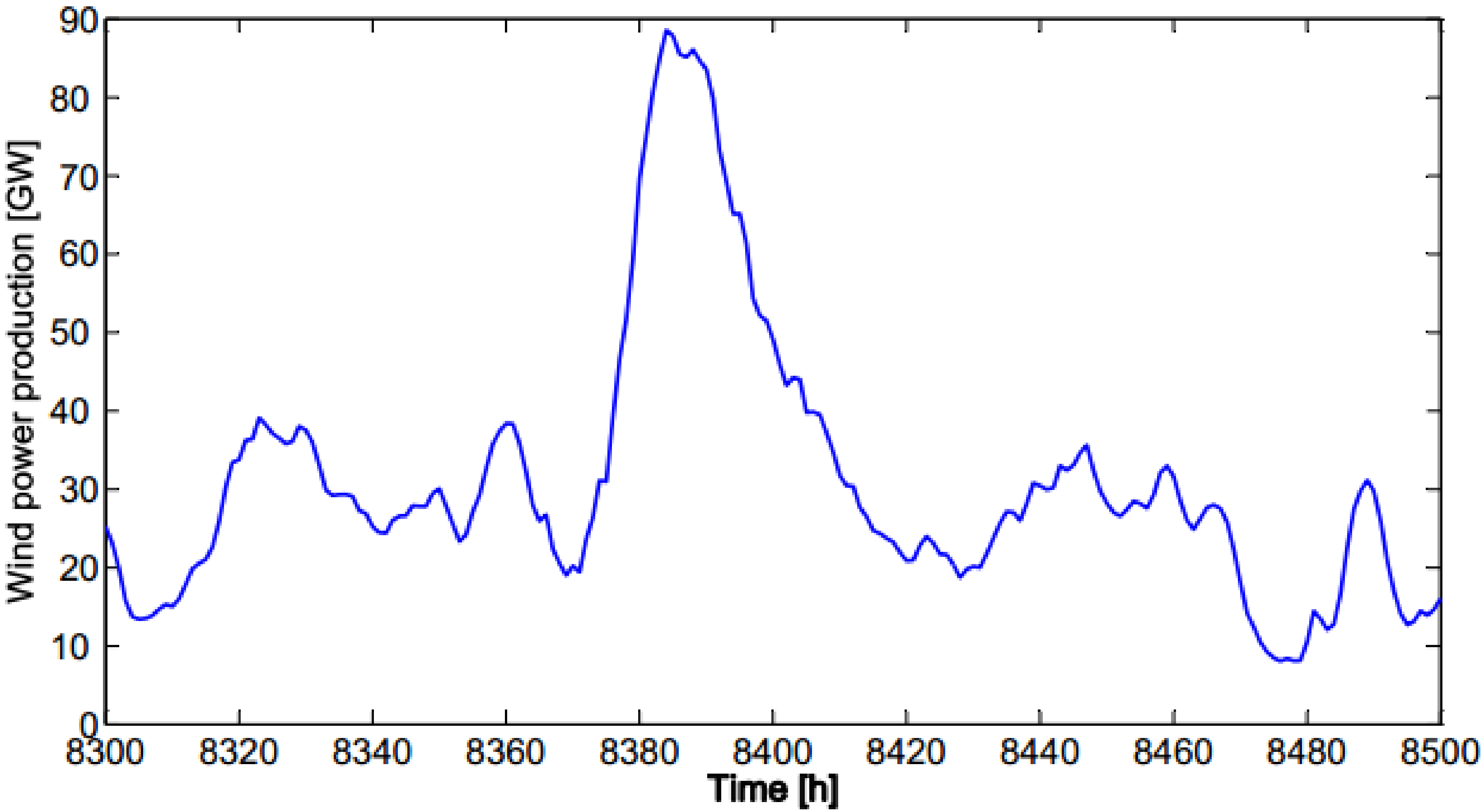
- **System operation for multiple records of 30- 70 precipitation years**
  - Generation per unit / type
  - reservoir storage, water flow
  - supply, consumption, trade
  - exchange between areas
- **Marginal value of electrical energy (represents forecast of market price)**
- **Economic results**
  - Socio-economic surplus
  - Curtailment
  - Quota prices
- **GHG emissions**

Example of spot price scenarios



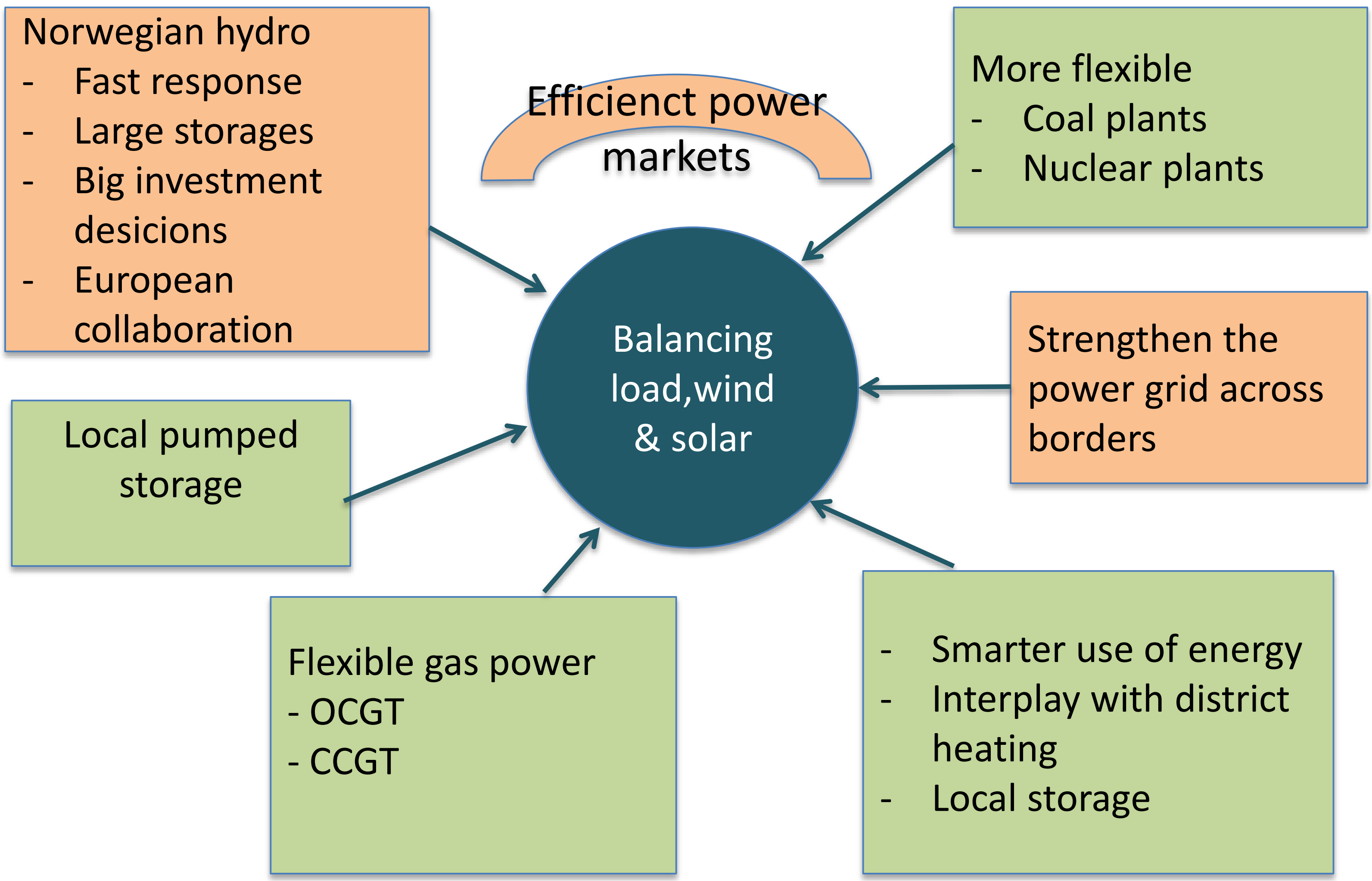
Statnett.no

Houston, we have a ~~problem~~ ..challenge!

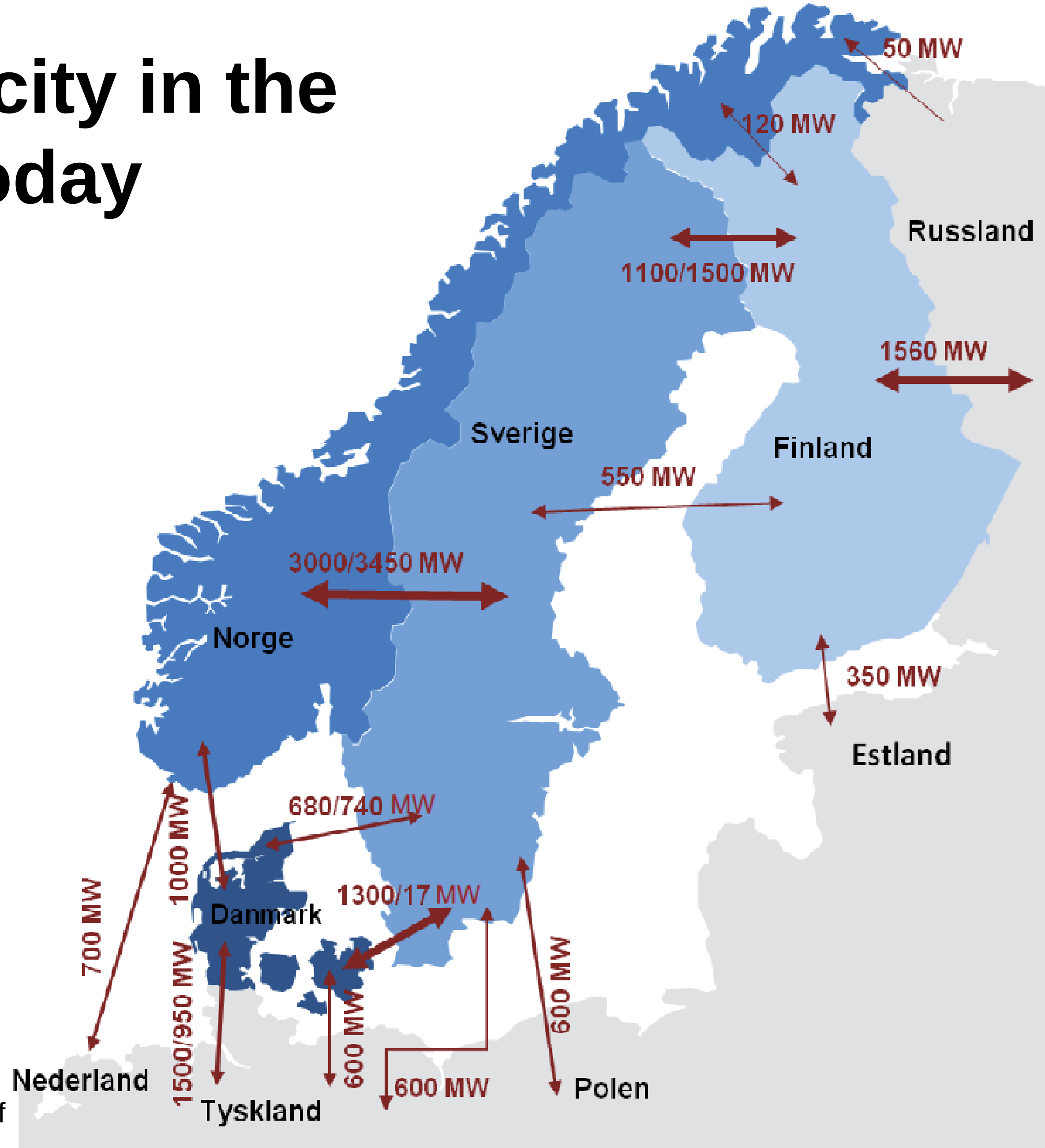


Source: Aigner (NTNU)

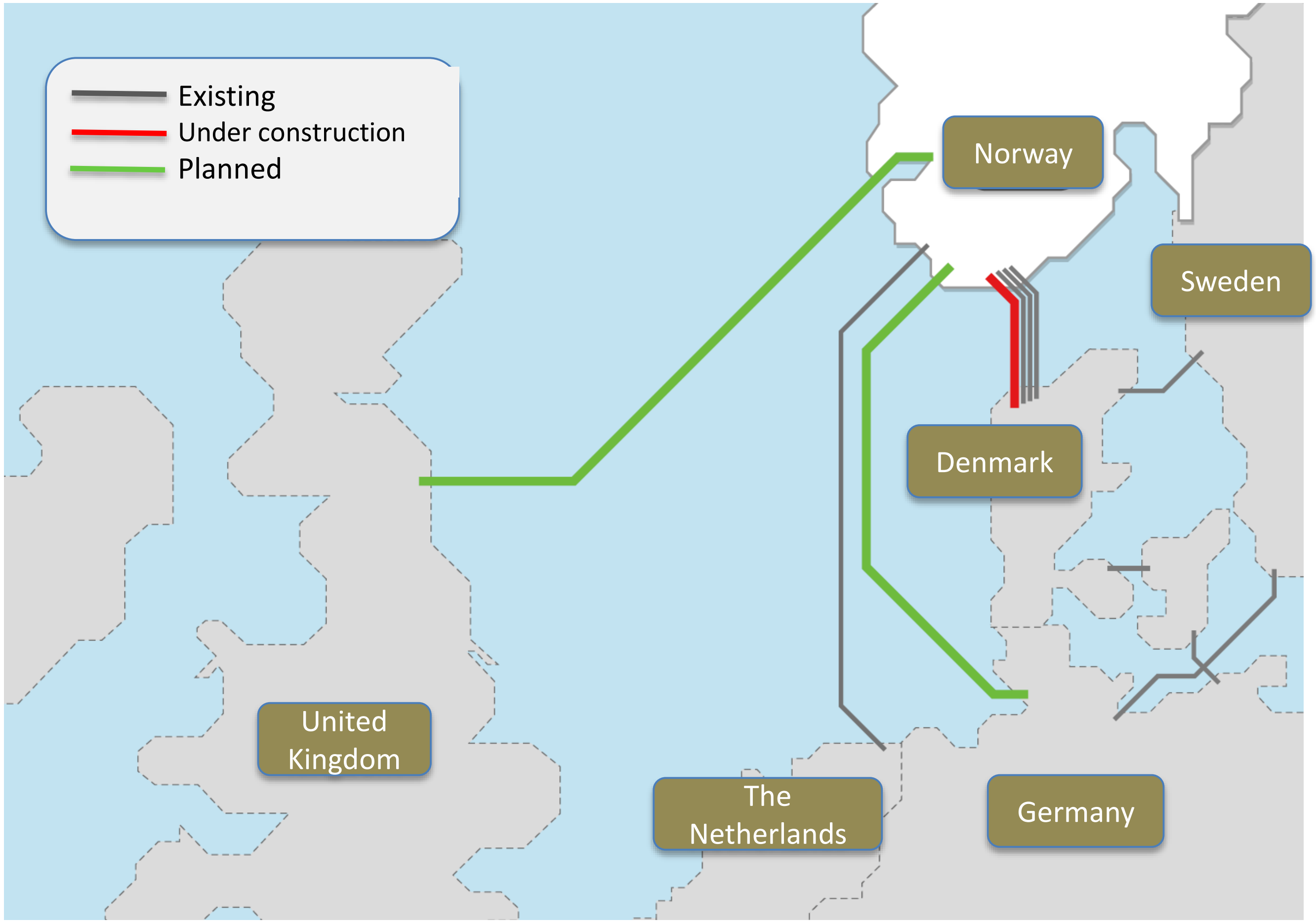
…and a whole lotta solutions!



Exchange capacity in the nordic region today



Cable connection development



Source: Statnett

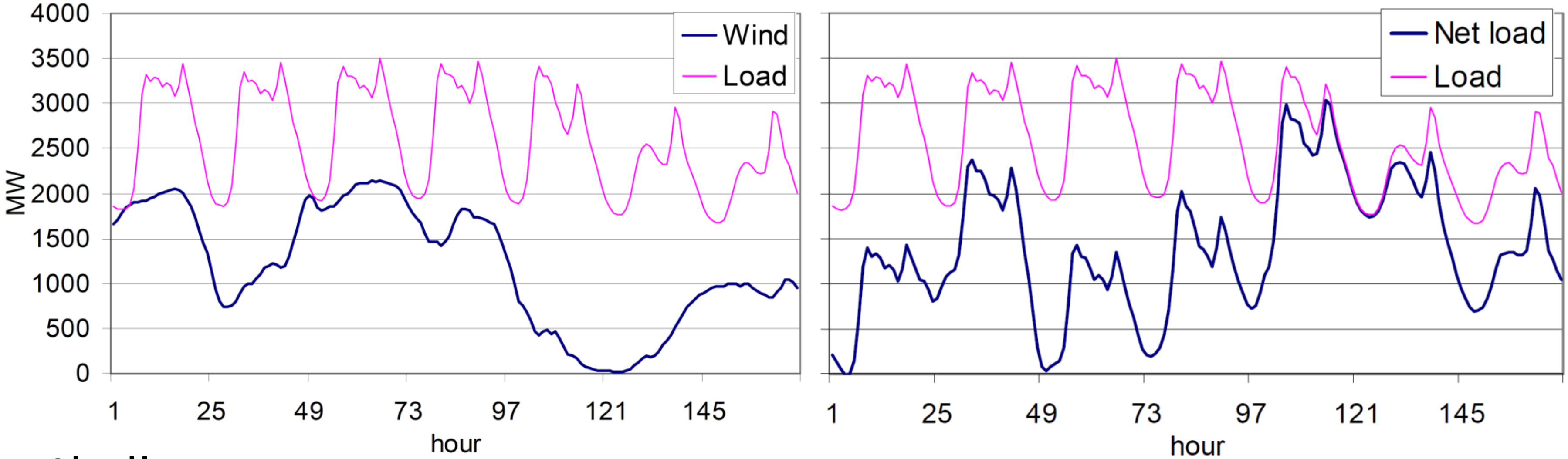
Properties of a market that enhances flexibility

- Common markets for spot, balancing og grid service across borders
- More frequent updates of production plans
- Market clearing closer to real-time
- Consumers participate activly

- Allow «extreme» prices or introduce capacity markets
  - The «Merit order effect» of RES

It is the Net Load that matters

- The system will see the aggregated net imbalance
  - Unforeseen variations in load, wind and solar
  - Net load = Load – Wind – Solar

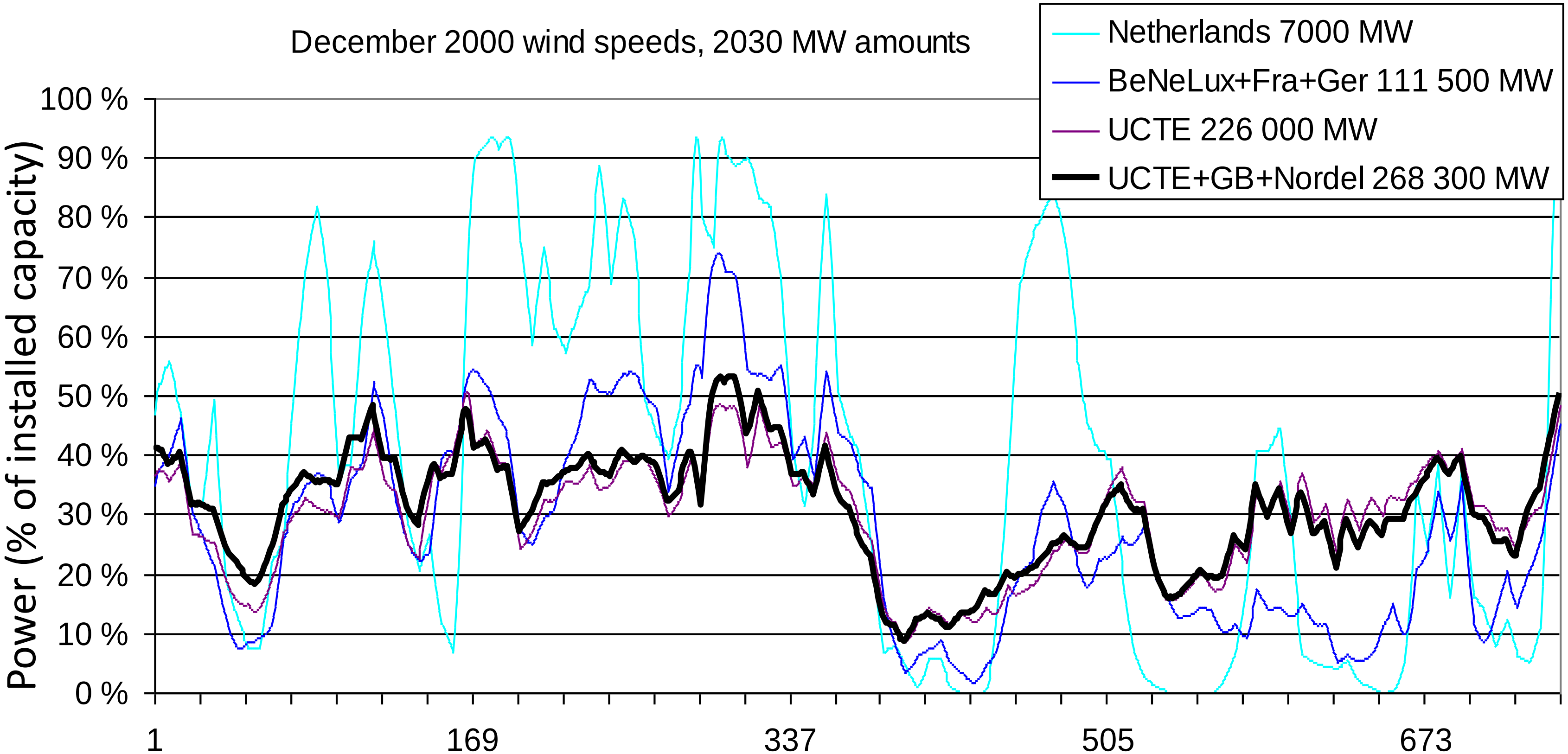


Challenges:

- Flexibility of thermal power plants (ramp rates, start/ stop operation)
- With very high RE share, thermal plants can be pushed out of the market – security of supply has to be fulfilled

Sources: NREL, Holttinen (VTT)

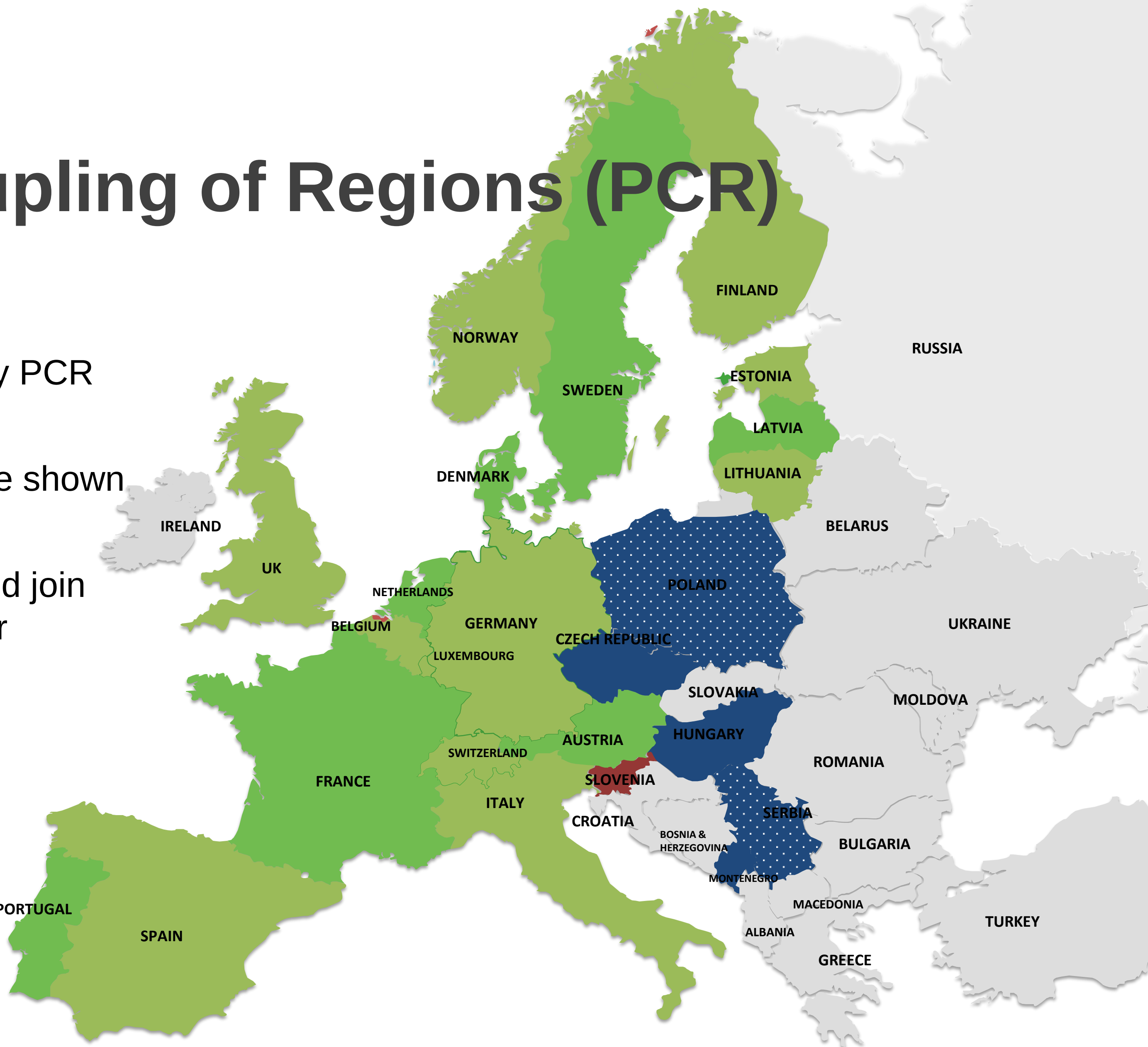
Smoothing effect of variability



Pan-European balancing can reduce storage needs of wind+PV by a factor of 11 compared with regional storage

Price Coupling of Regions (PCR)

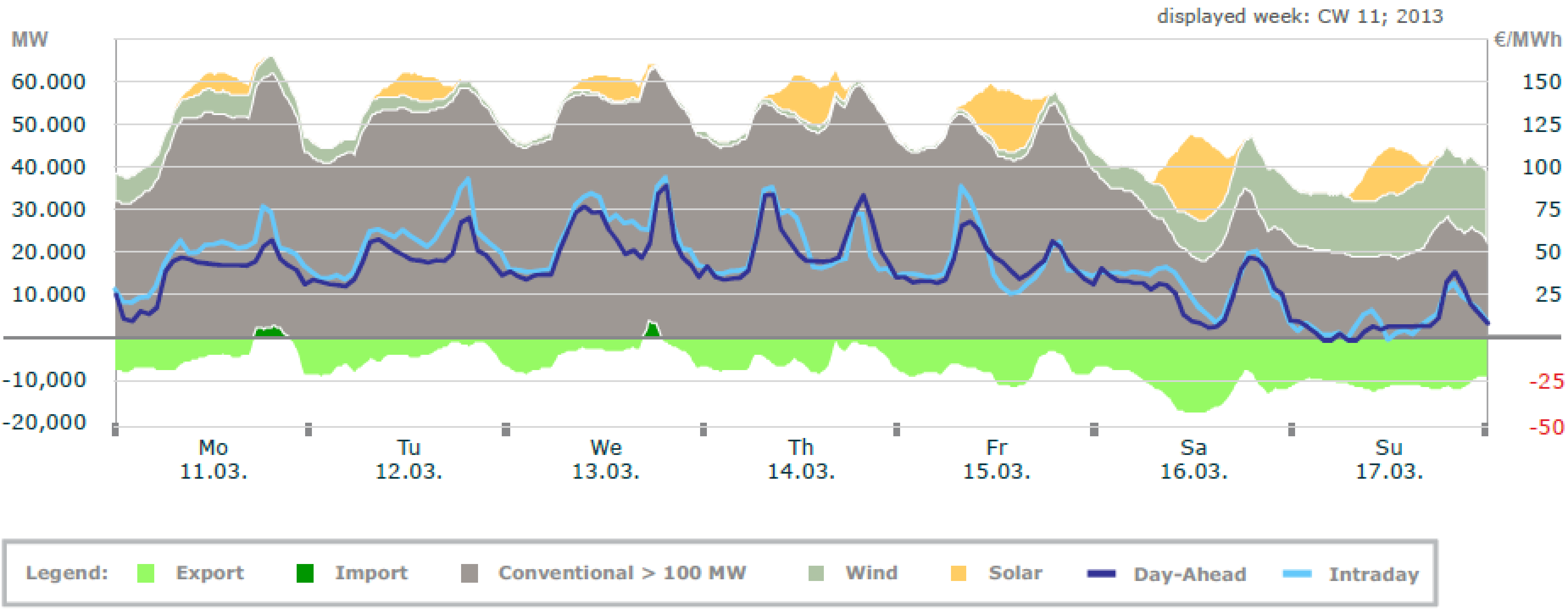
- Markets covered by PCR (2860 TWh)
- Markets which have shown interest to join
- Markets which could join as a part of a larger European plan



Source: nordpoolspot

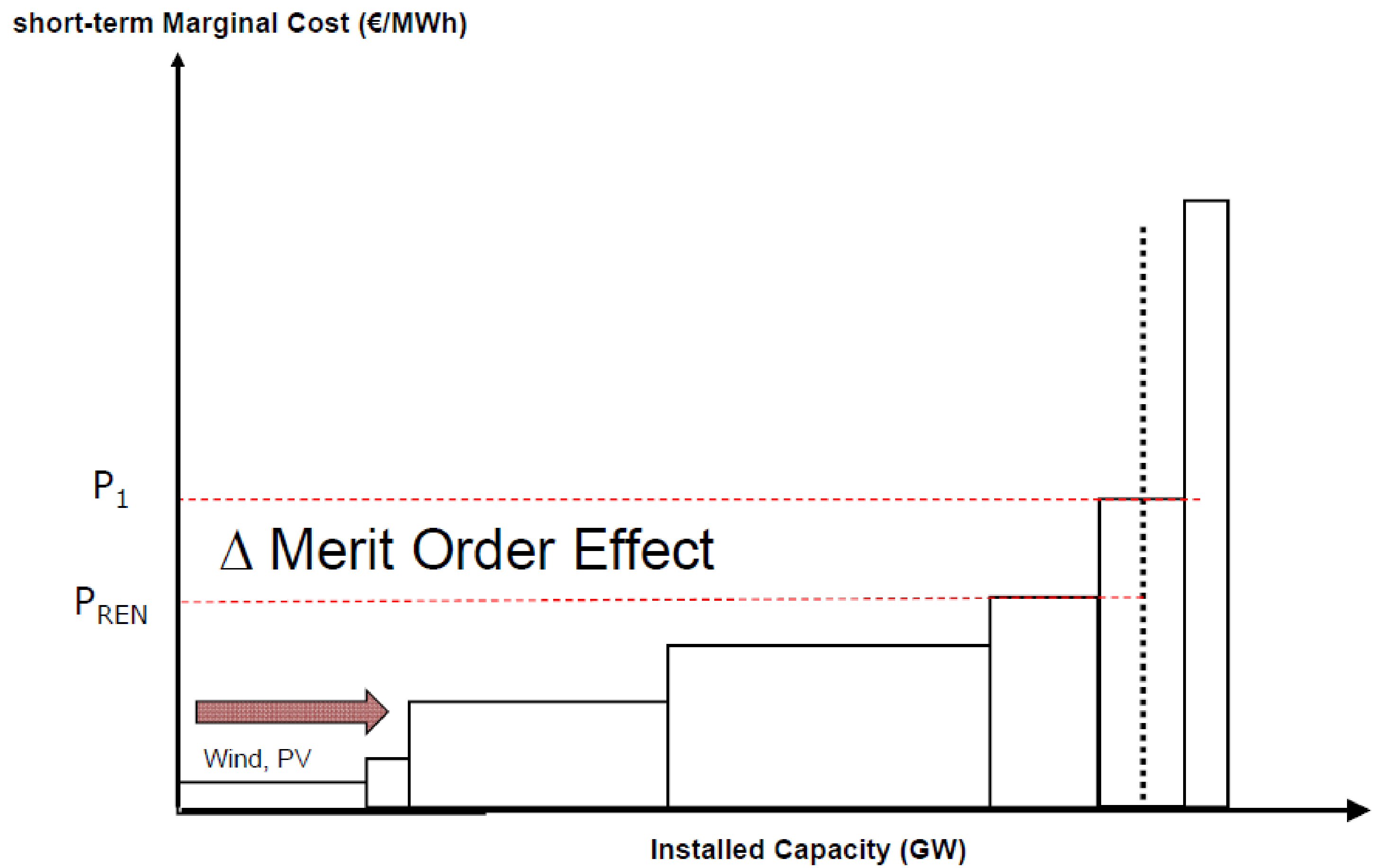
The relation between wind/solar and price

Example from Germany

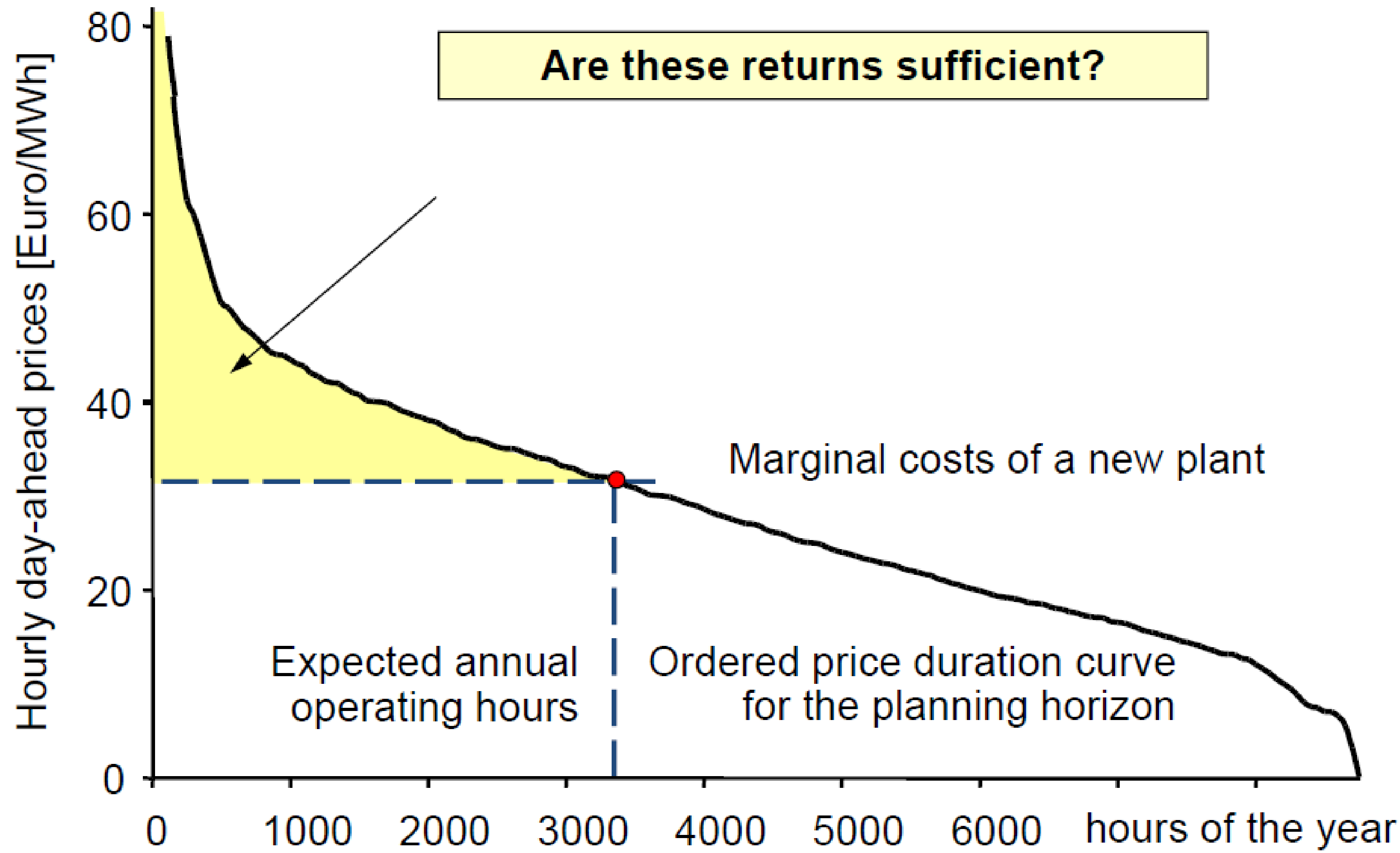


Source: J. Mayer, Fraunhofer ISE

Variable Renewables and Implications for Market Prices: Merit Order Effect



Price-Duration-Curve: Power Plant Investments on Competitive Markets



Source: Erdmann 2011

The power system model

75 climatic years
(wind, solar, inflow, temperature)

2 hours resolution

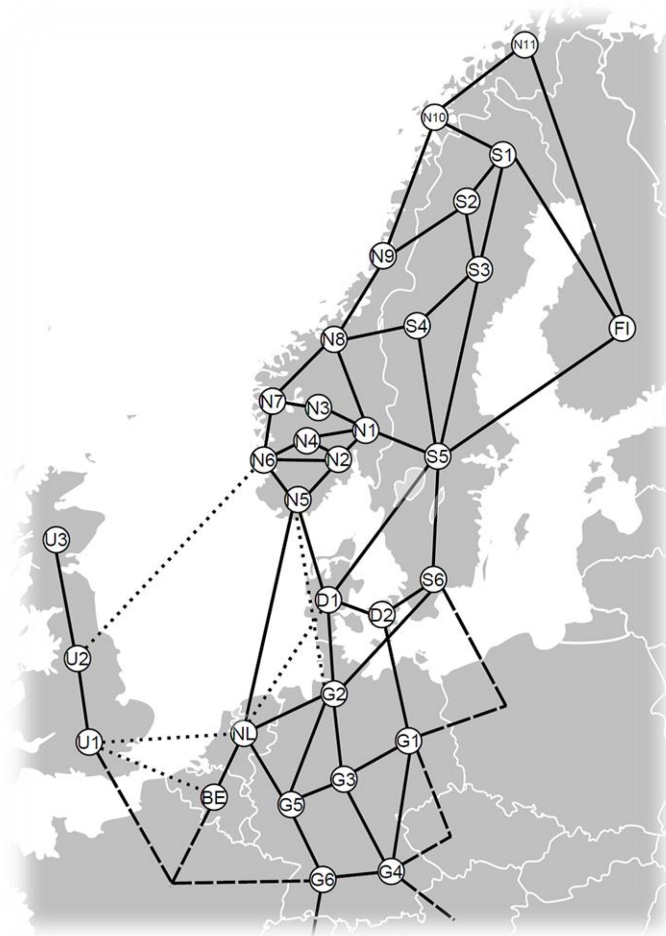
52 areas

about 1500 power plants

80 transmission corridors

Stochastic optimisation

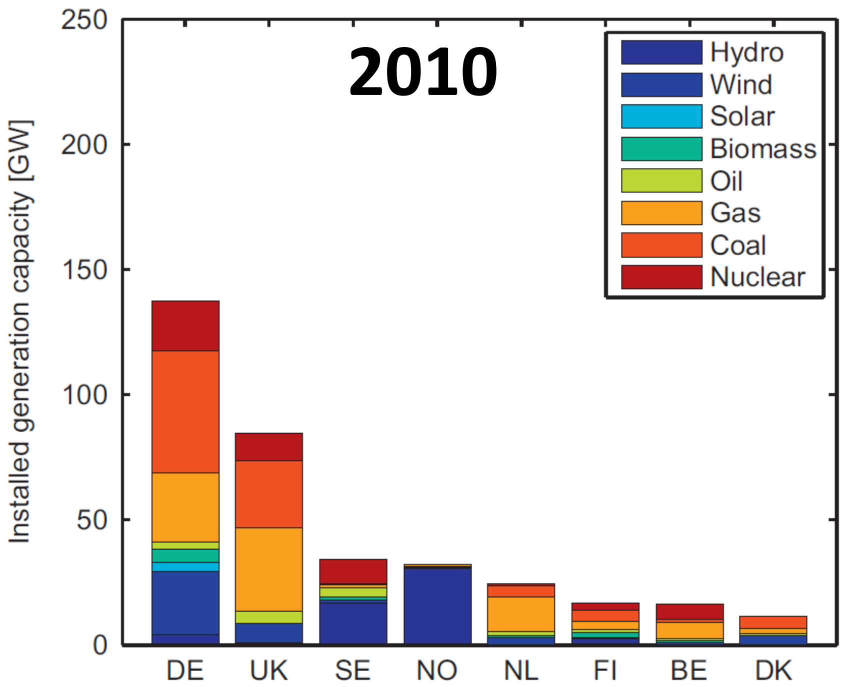
Unit commitment and dispatch

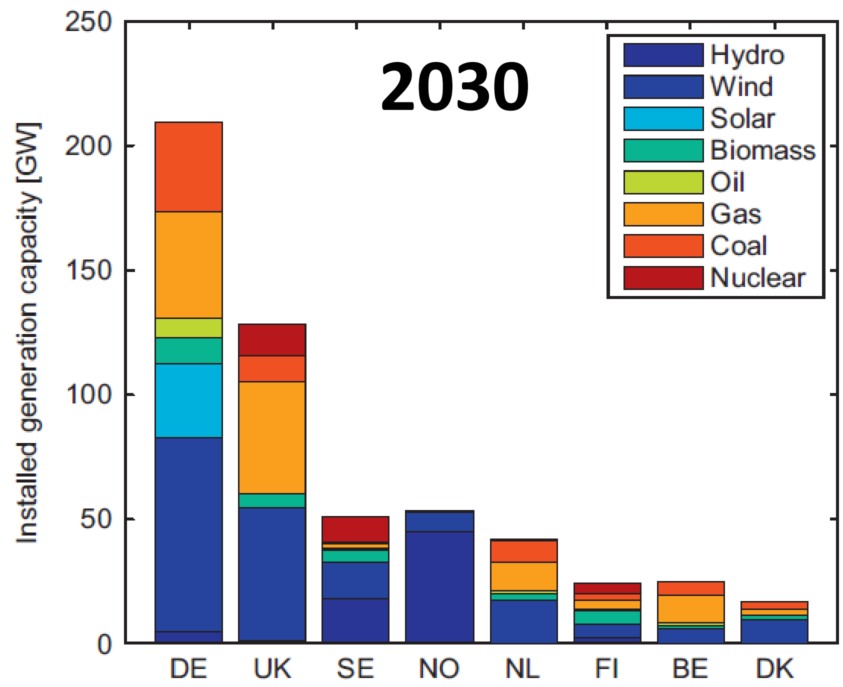


Source: Jaehnert, Korpås, Doorman (NTNU)

Scenarios for generation capacity

- Phase-out of nuclear in Germany
- Much more wind power in Europe (and solar in Germany)
- +11 GW hydro generation capacity in Norway (+5 GW pumpinig)
- Consumption increases with 5-15 %, depending on country

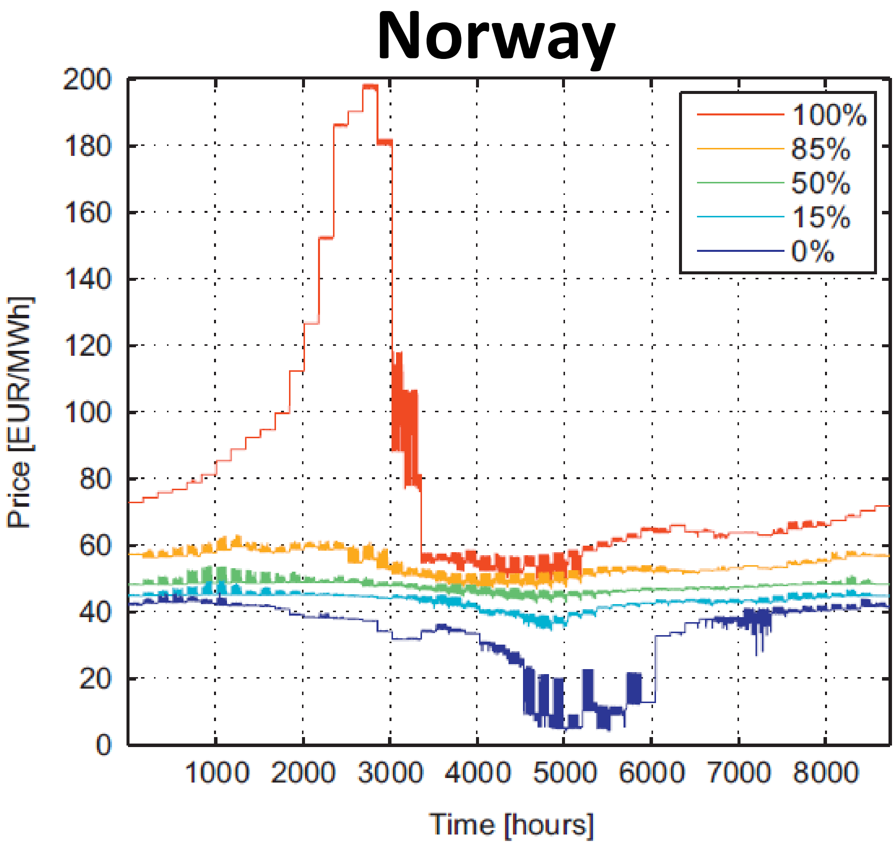


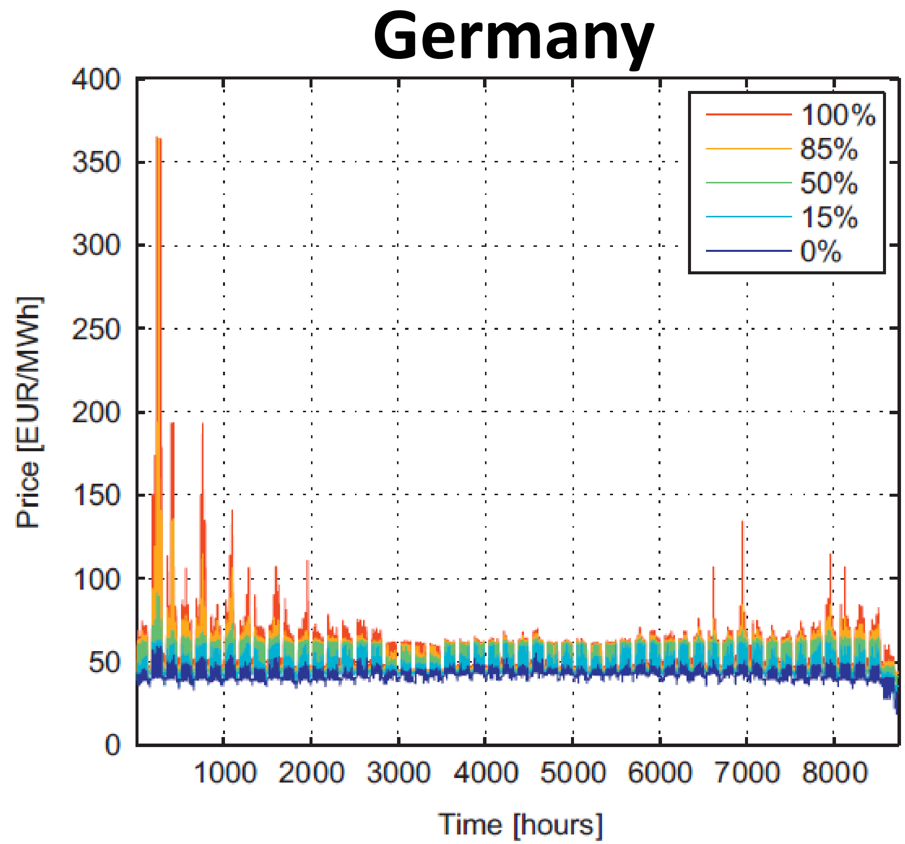


Source: Jaehnert, Korpås, Doorman (NTNU)

Simulated electricity prices in 2010

- Daily prices in Germany reflects the costs of thermal power
- Seasonal prices in Norway depends on the available water

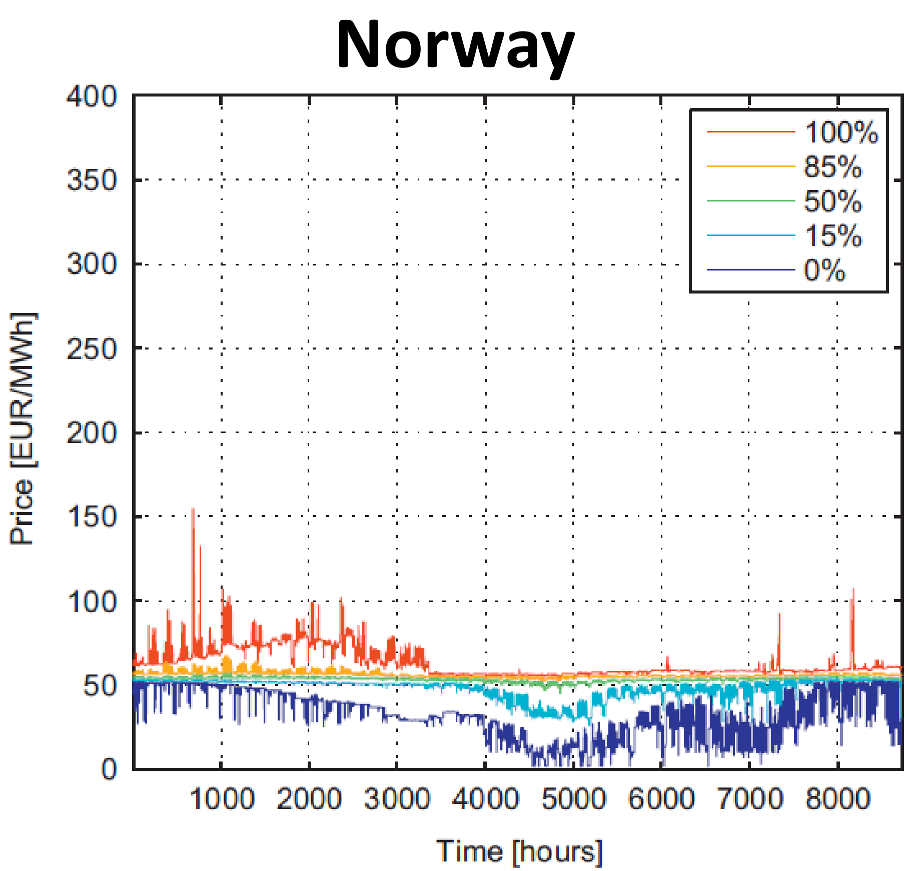


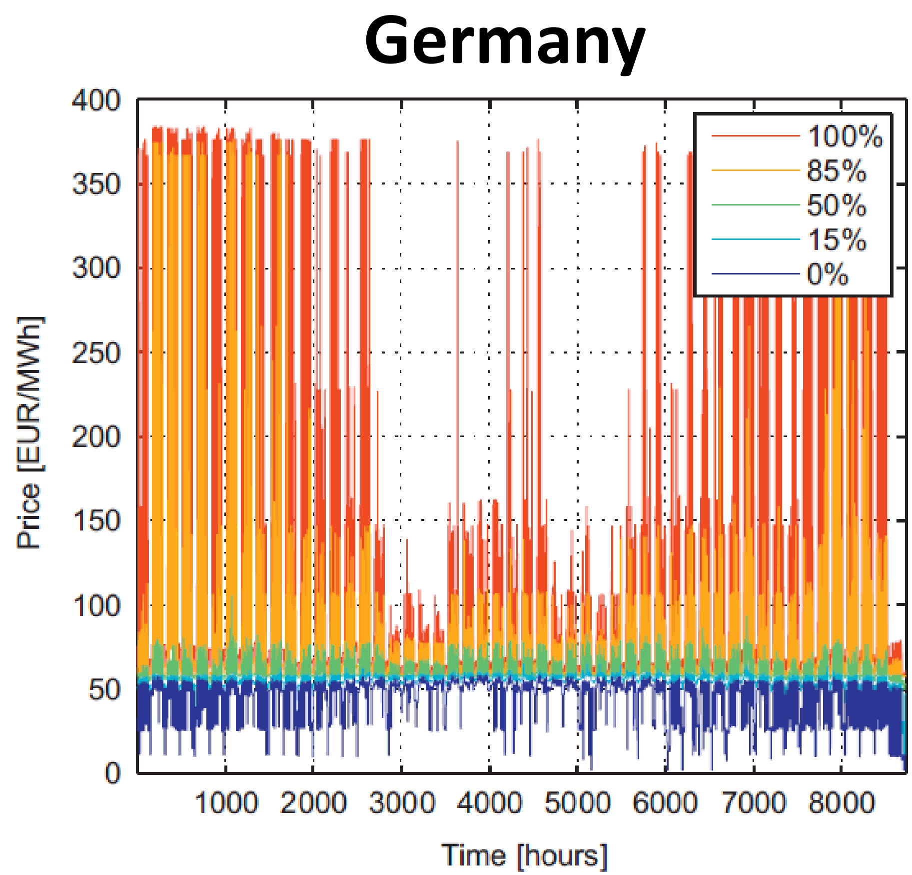


Source: Jaehnert, Korpås, Doorman (NTNU)

Simulated electricity prices in 2030

- Higher short-term price variability in Germany
- Lower short-term price variability in Norway



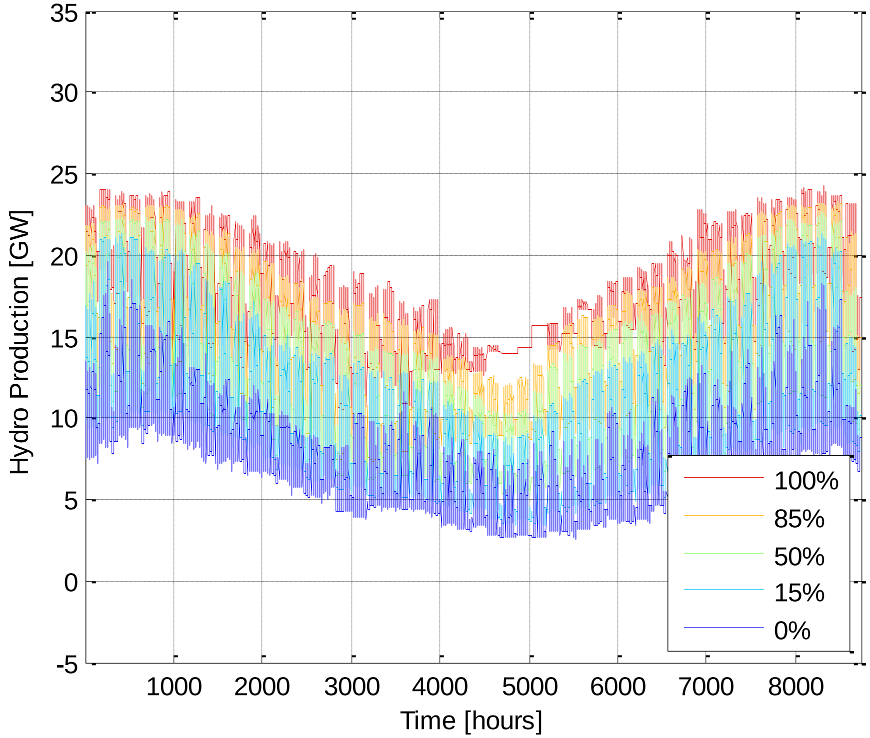


Source: Jaehnert, Korpås, Doorman (NTNU)

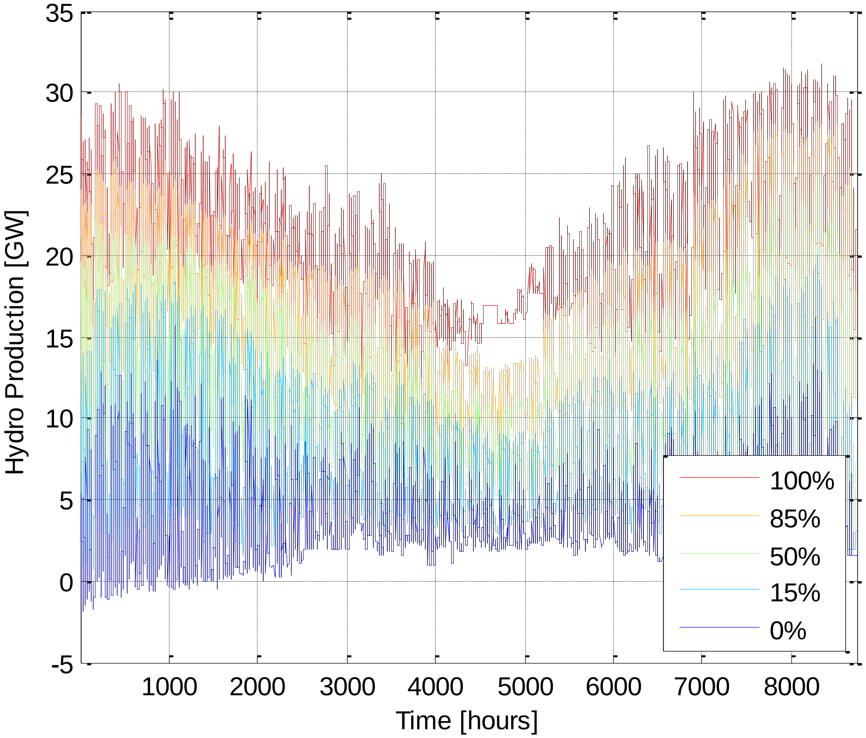
Norwegian hydro production

- Increased production variability due to balancing of WPP

2010



2030

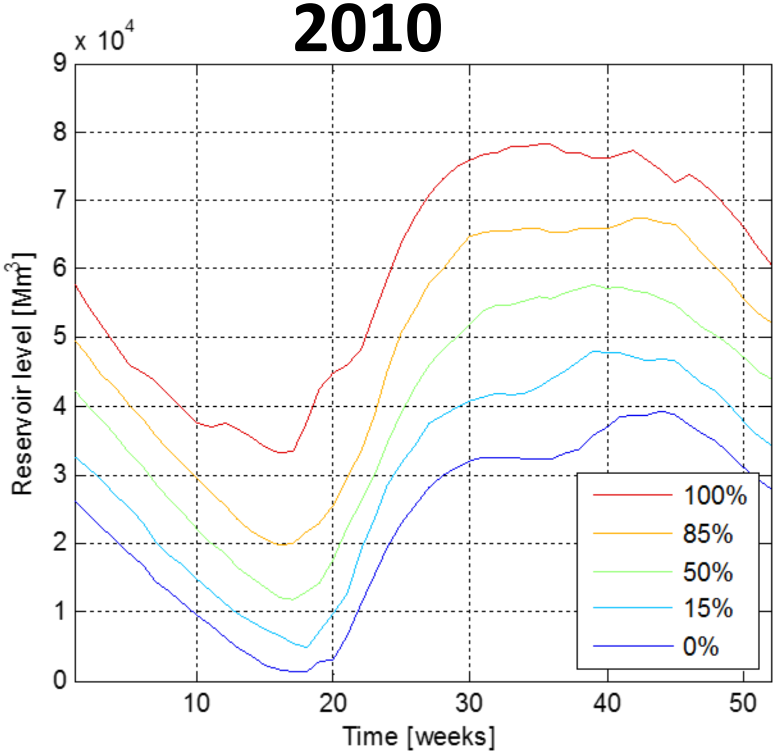


Source: Jaehnert, Korpås, Doorman (NTNU)

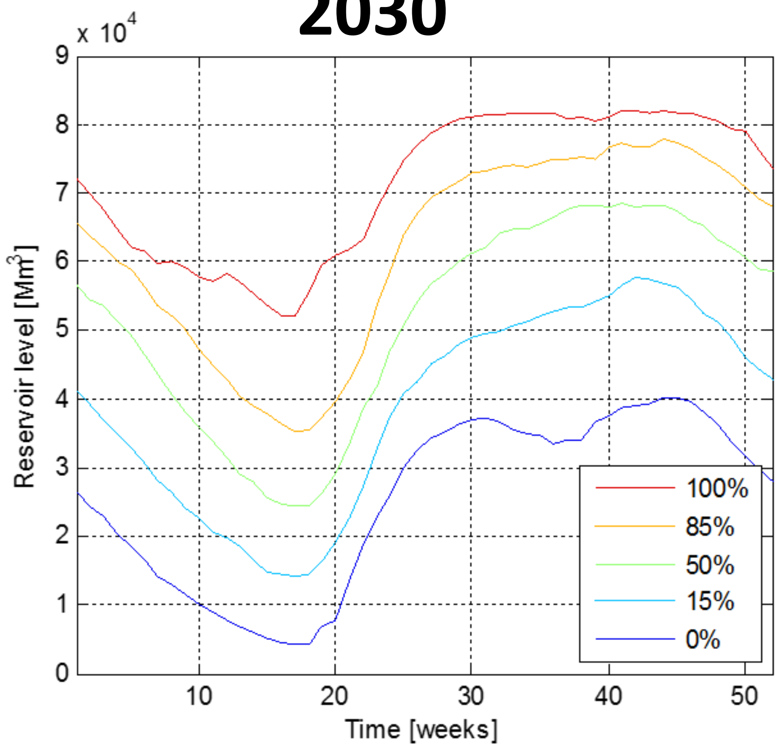
Norwegian reservoir handling

- Almost similar pattern: Still unused storage potential
- Higher levels due to increased inflow

2010

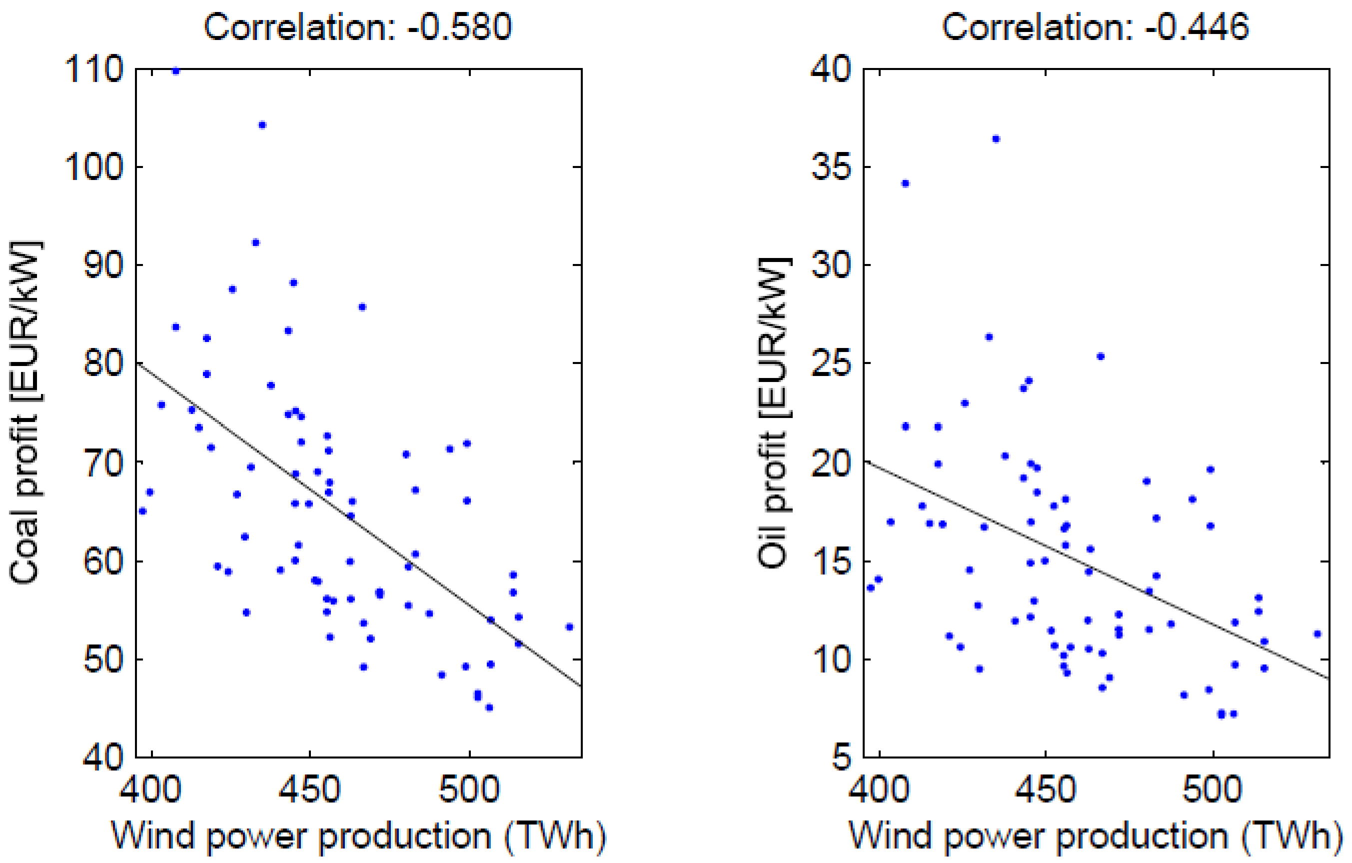


2030



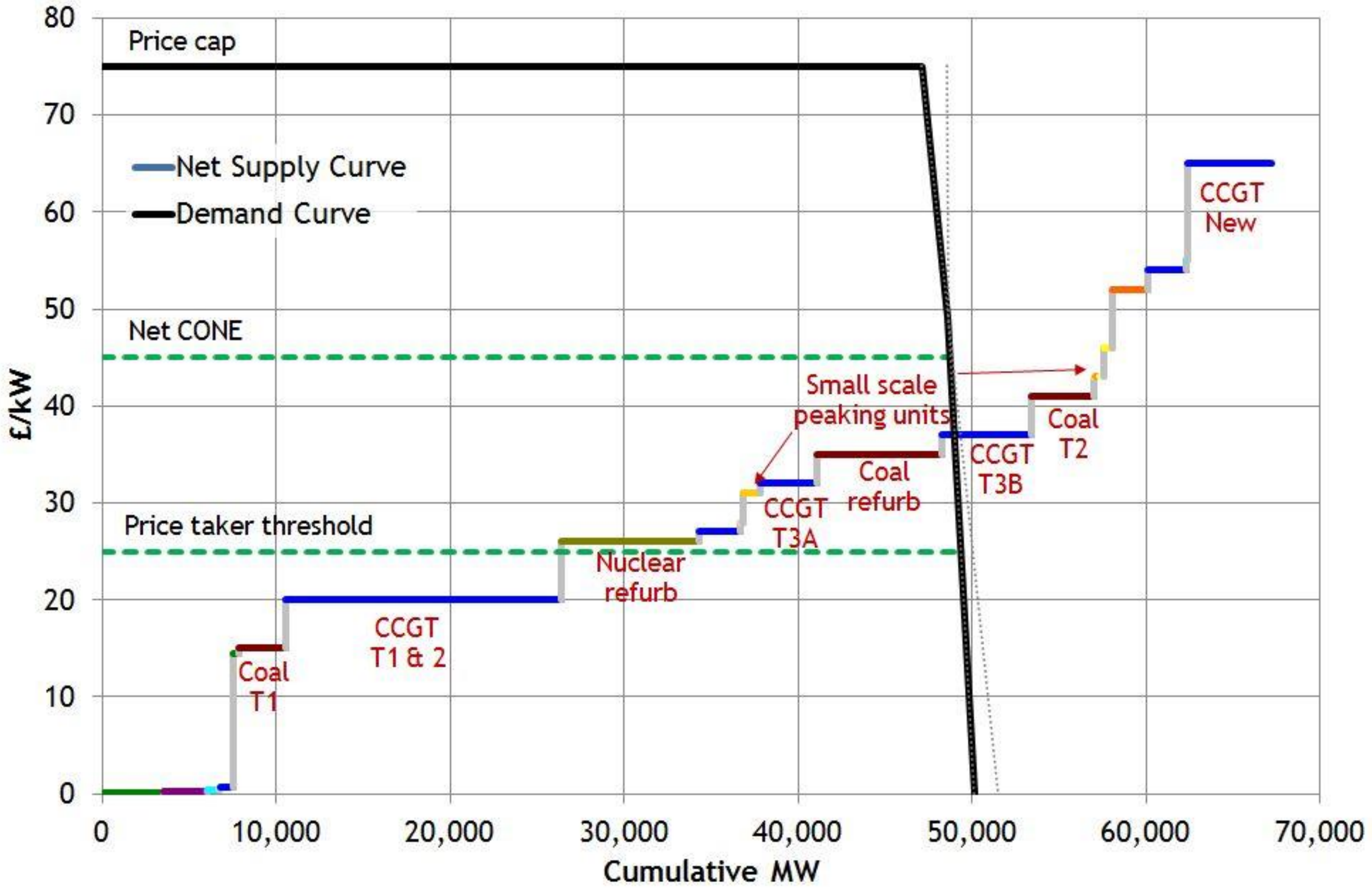
Source: Jaehnert, Korpås, Doorman (NTNU)

Wind and solar pushes fossils out of the spot market…



Source: Jaehnert, Korpås, Doorman (NTNU)

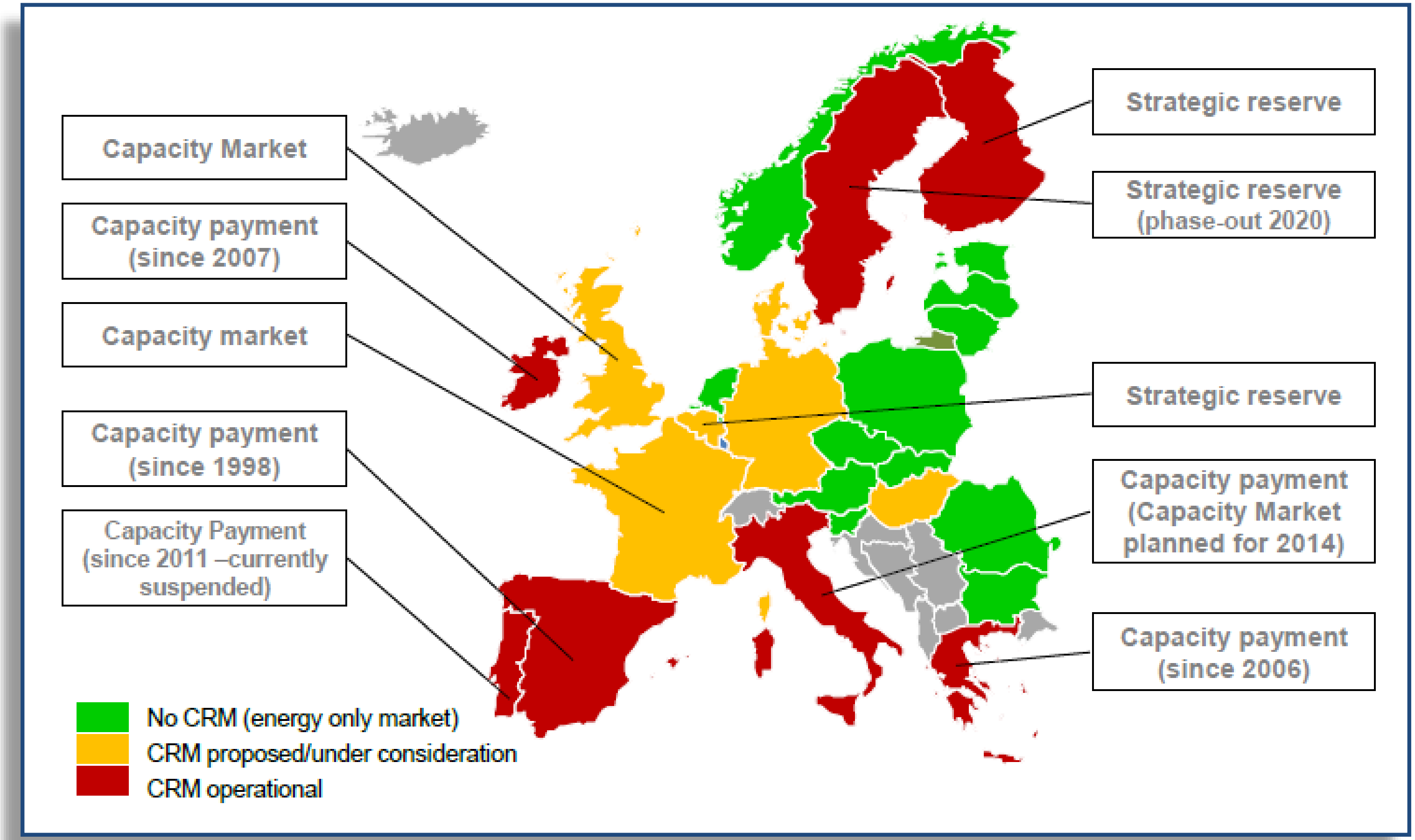
…and into the (emerging) capacity markets



Source: Timera Energy (UK)

Capacity remuneration mechanisms

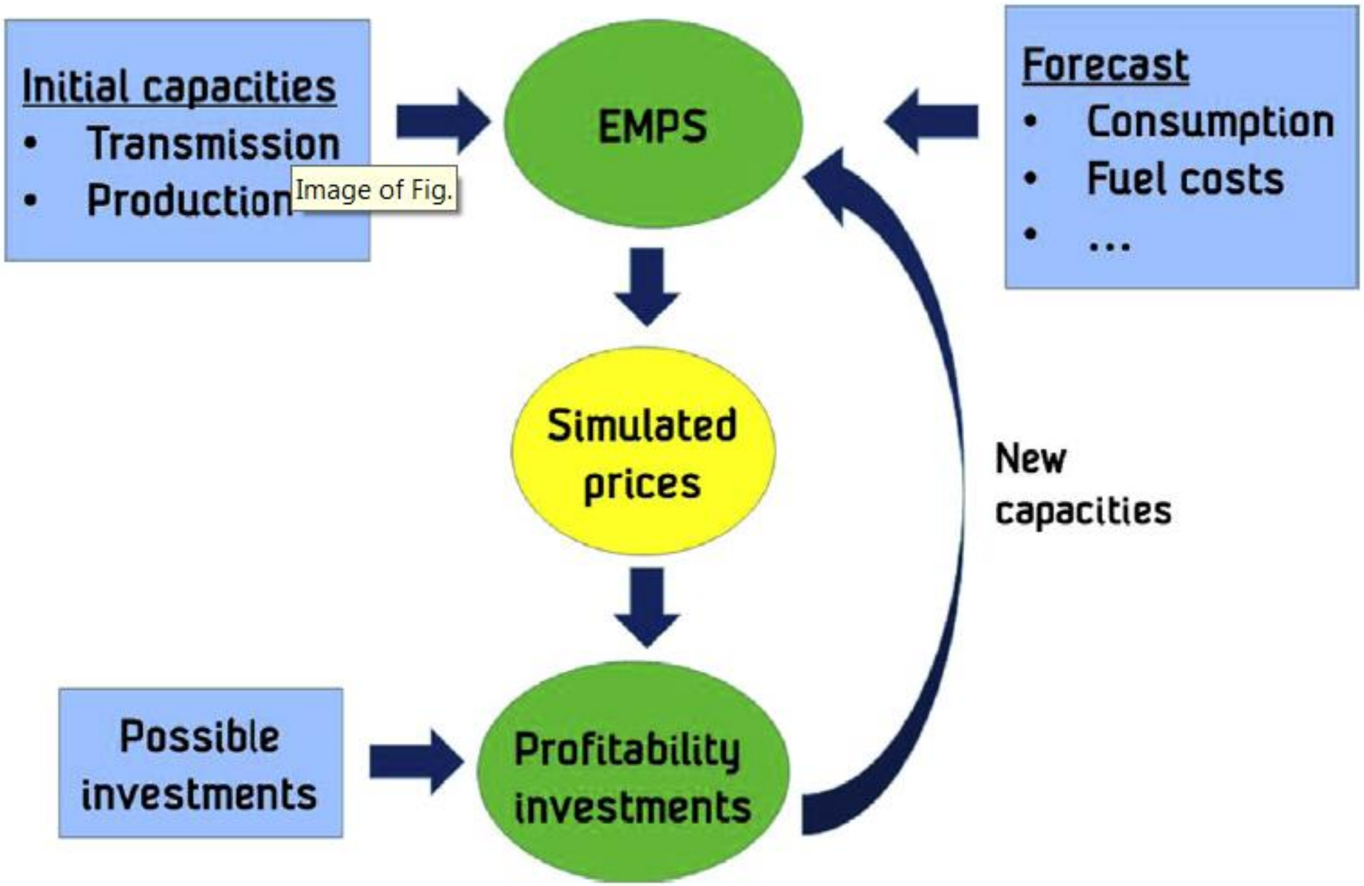
throughout Europe



Source: ACER, "Report: CAPACITY REMUNERATION MECHANISMS AND THE INTERNAL MARKET FOR ELECTRICITY", 2013

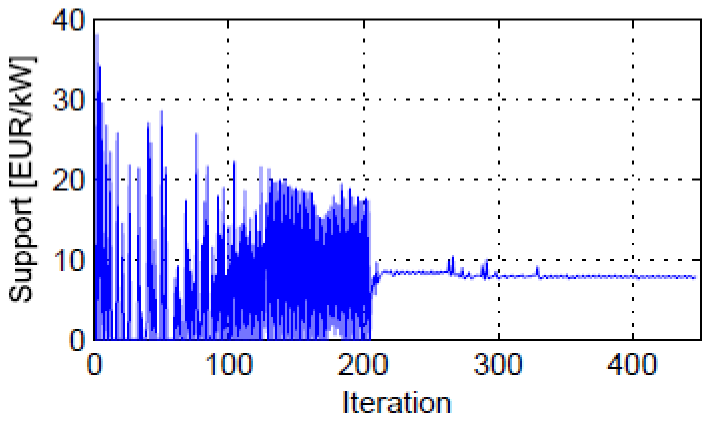
Extending the EMPS market model with a capacity market

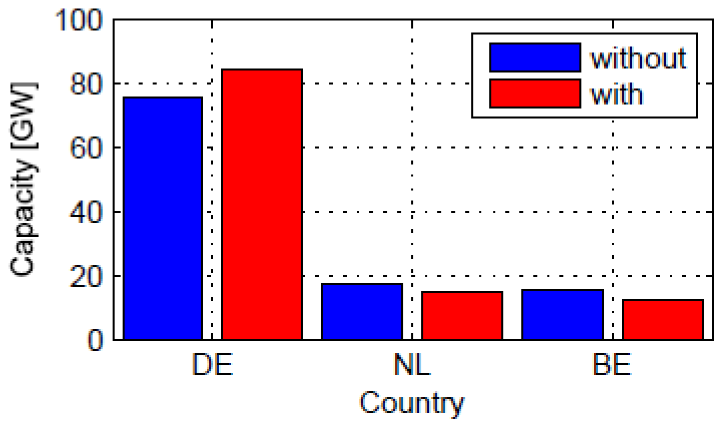
Investment algorithm for transmission grid development

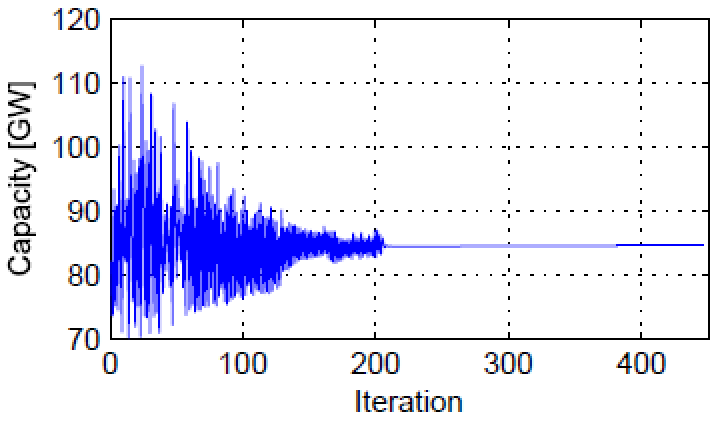


Assessing a capacity requirement

in Northern Europe



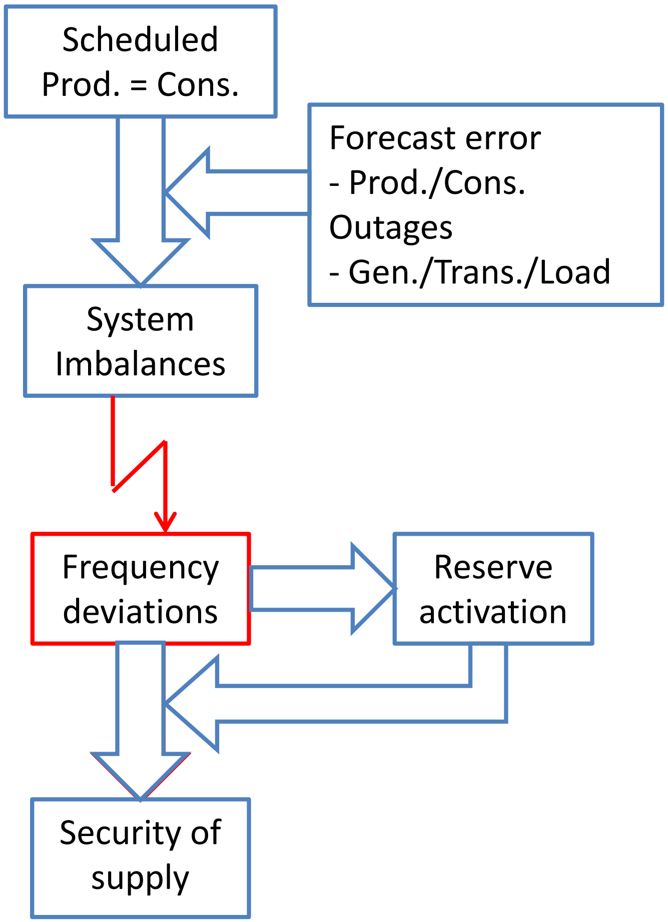


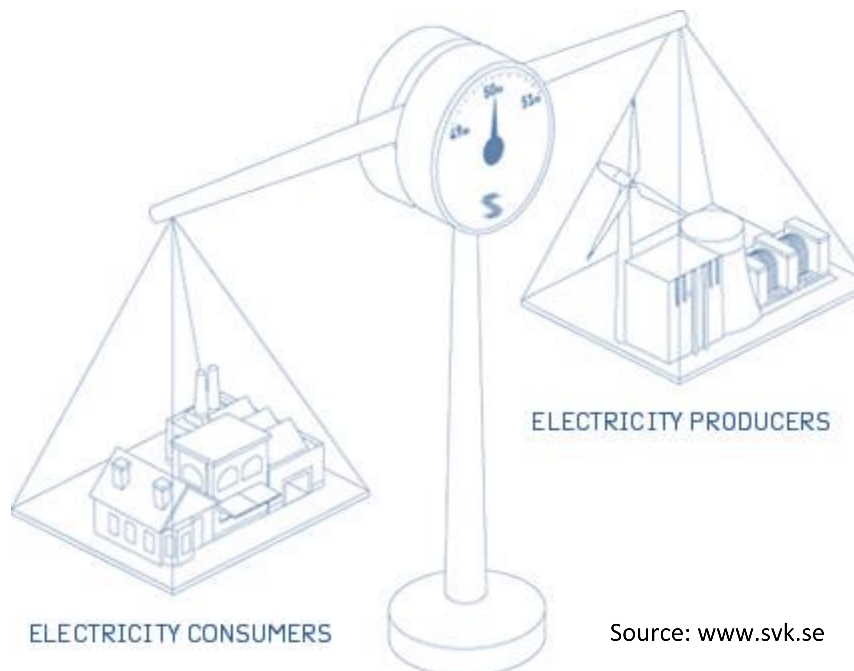


- 85 GW capacity requirement in Germany
- Convergence after about 450 iterations
- 8'800 €/MW capacity remuneration
- Effect on neighbouring countries

Balance management

Production = Consumption

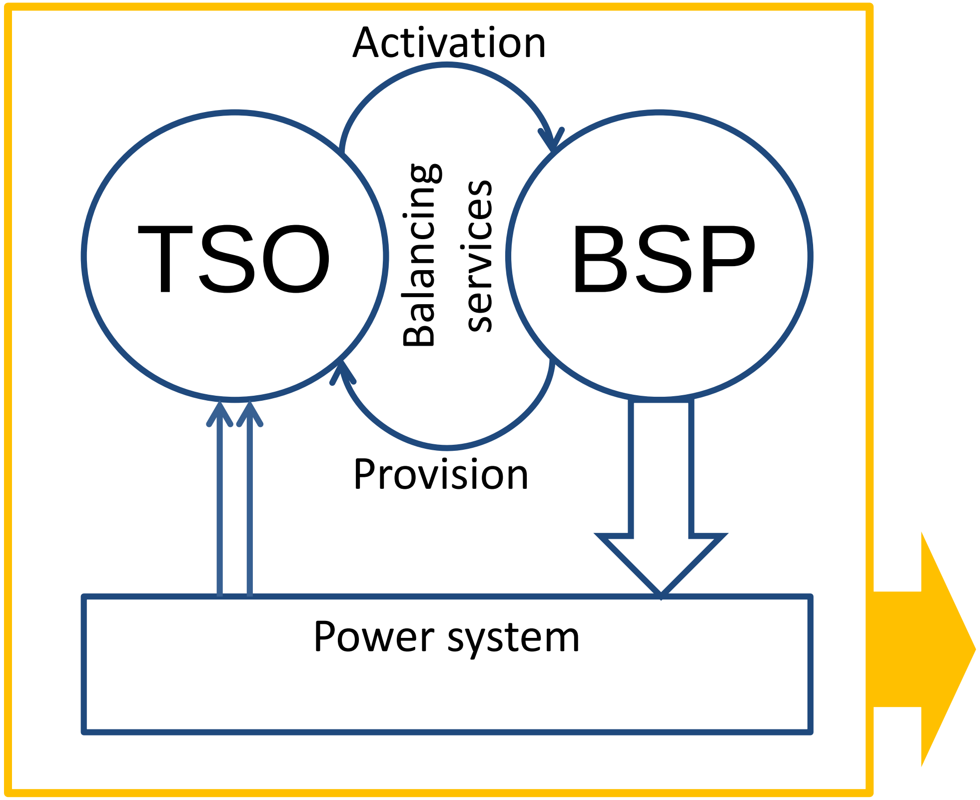




Source: www.svk.se

Balance management

Framework



- TSO – Transmission System operator (Balance responsibility)
- BSP – Balancing Service Provider (Generator, Demand)

Framework:
Regulating power market
(Balancing market)

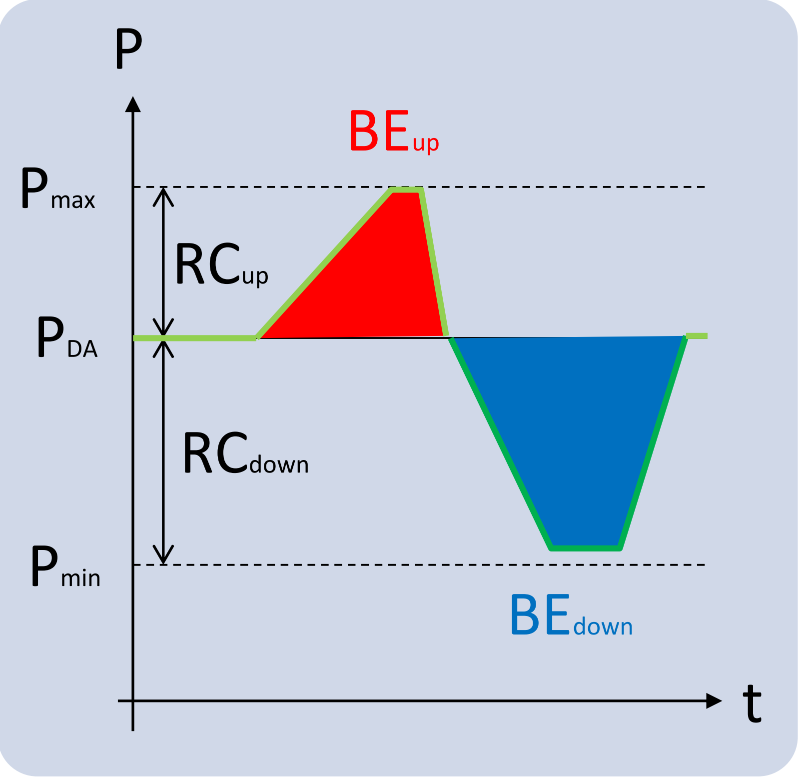
Balancing Reserve Capacity vs Energy

Reserve procurement

- Reserve capacity (RC) [EUR/MW]
- TSOs ensure sufficient reserves in the system during operation

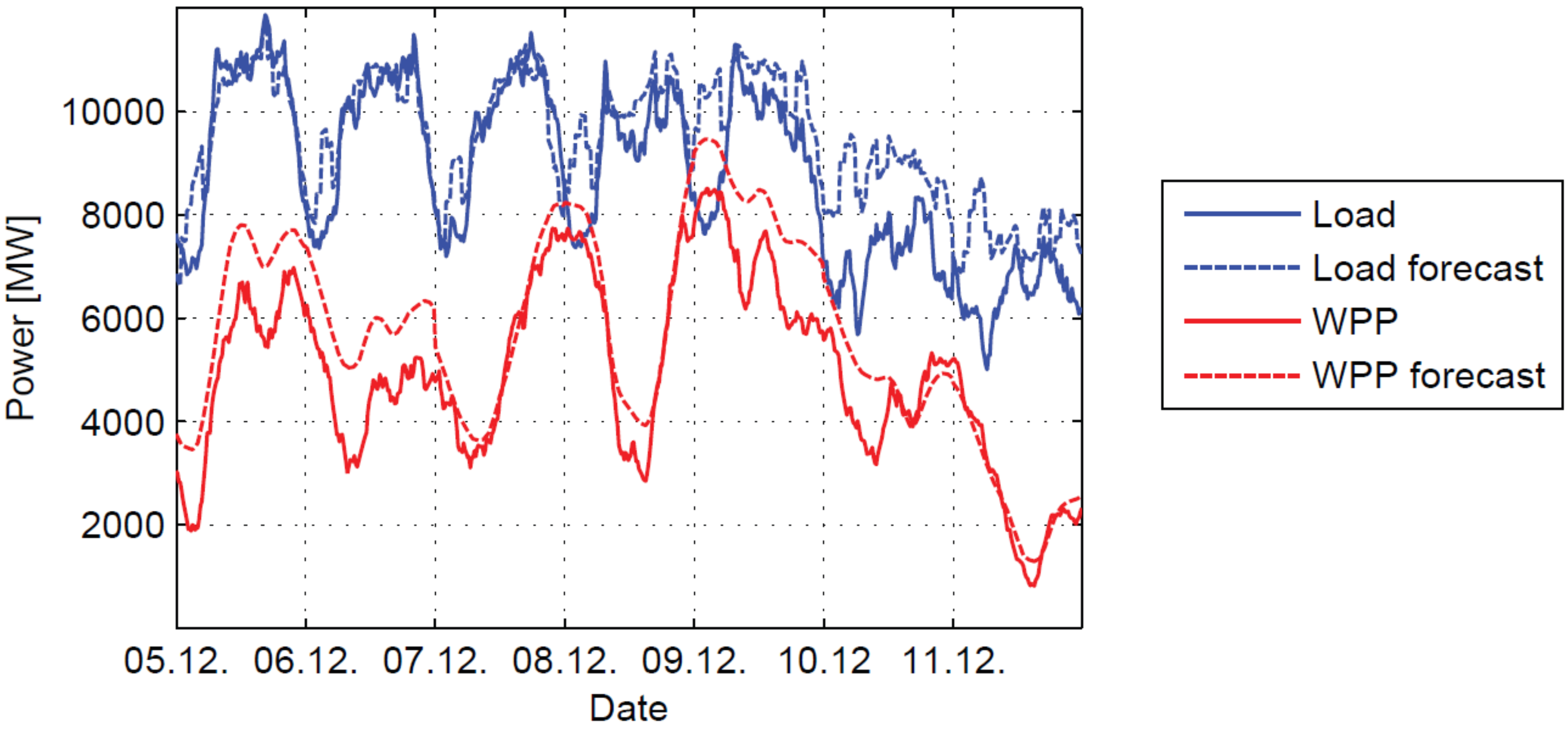
System balancing

- Balancing energy (BE) [EUR/MWh]
- TSOs activate reserves to counteract system imbalances



Source: Doorman (NTNU)

Wind forecasts are not that bad…

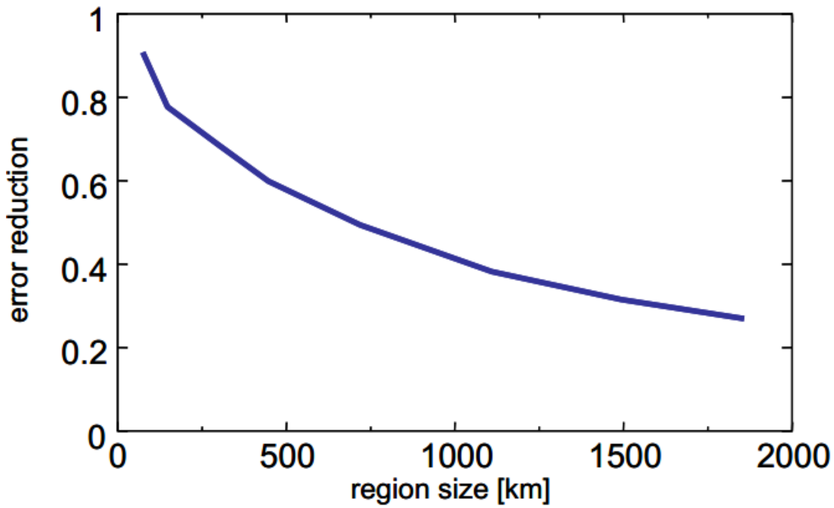


- Actual and predicted load and wind power forecasts in the 50Hertz area in Dec. 2011

Sources: Jaehnert (NTNU), www.50hertz.com

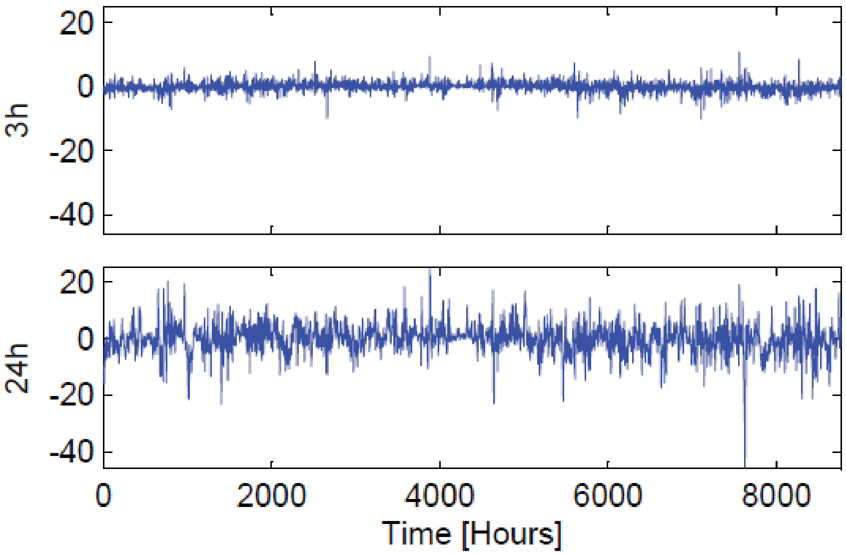
..but forecast horizon and geograpichal spread are essential

Geographical smoothing of forecast errors based on 40 German wind farms



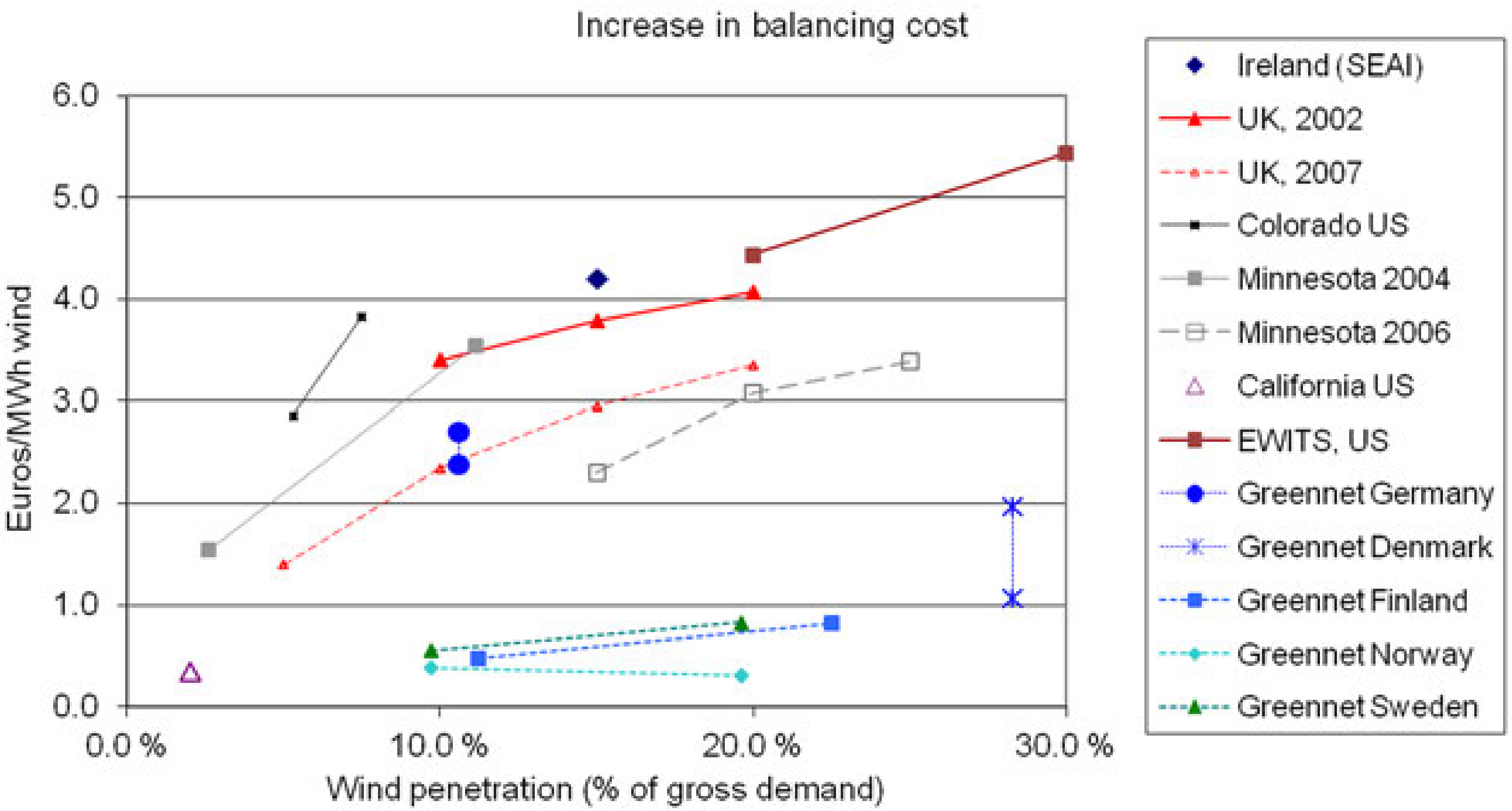
Source: energy & meteo systems, IEA Wind

Simulated forecast error [GW] in Northern Europe in 2020

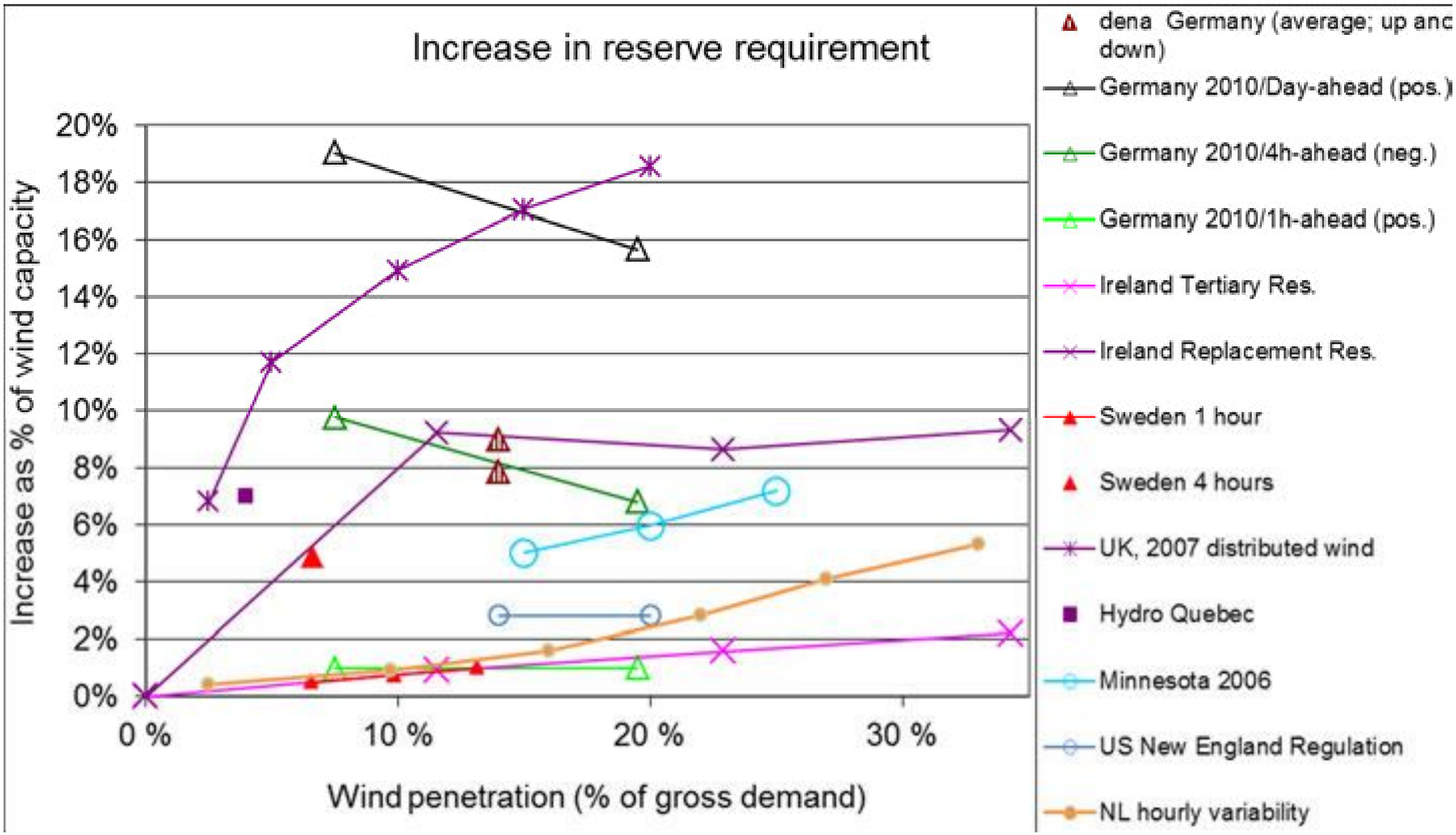


Source: Jaehnert (NTNU)

Increase in balancing costs due to wind



Increase in reserve requirement due to wind



Research Project

Balance management in multinational power markets

SINTEF

NTNU
Norwegian University of Science and Technology

TU Delft

The Research Council of Norway

NEXT GENERATION INFRASTRUCTURES

Statnett
Vårt felles kraftnett

TenneT
Taking power further

Statkraft

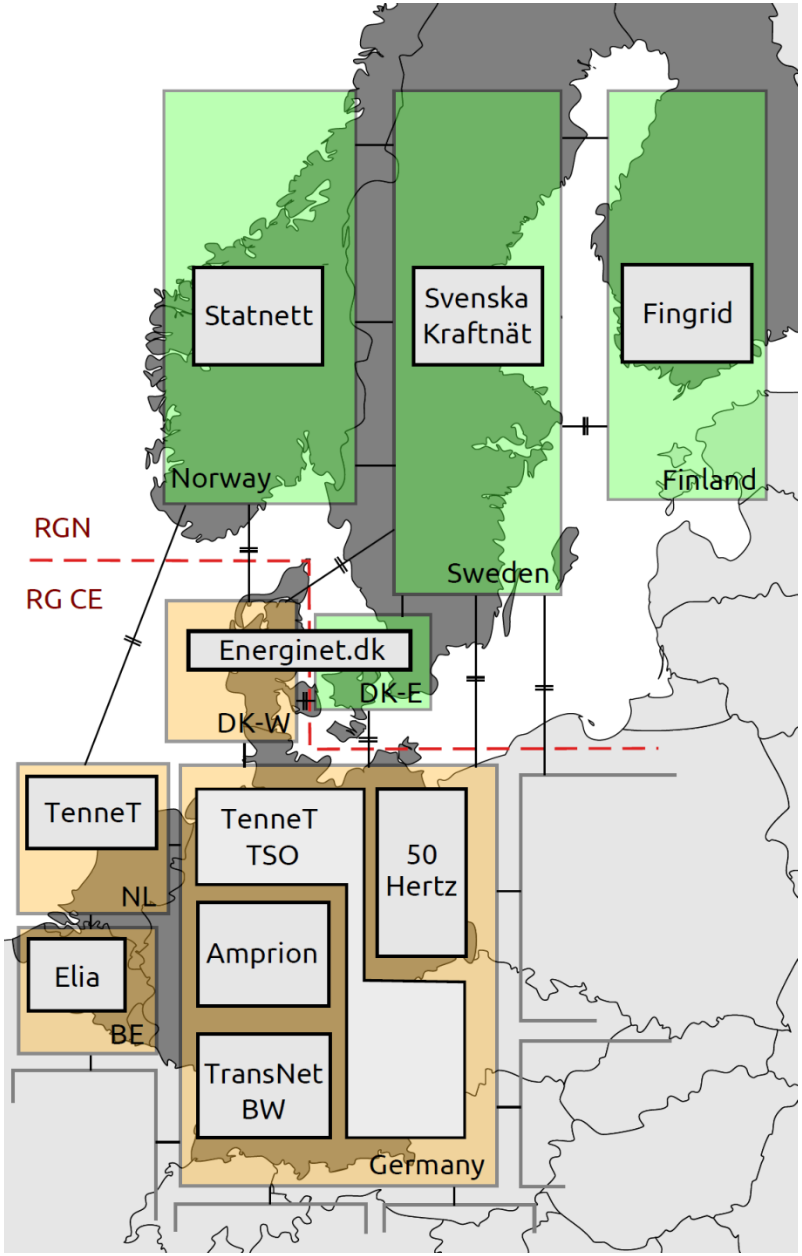
NVE

BKK

agder energi

Sira-Kvina KRAFTSELSKAP

GDF SUEZ



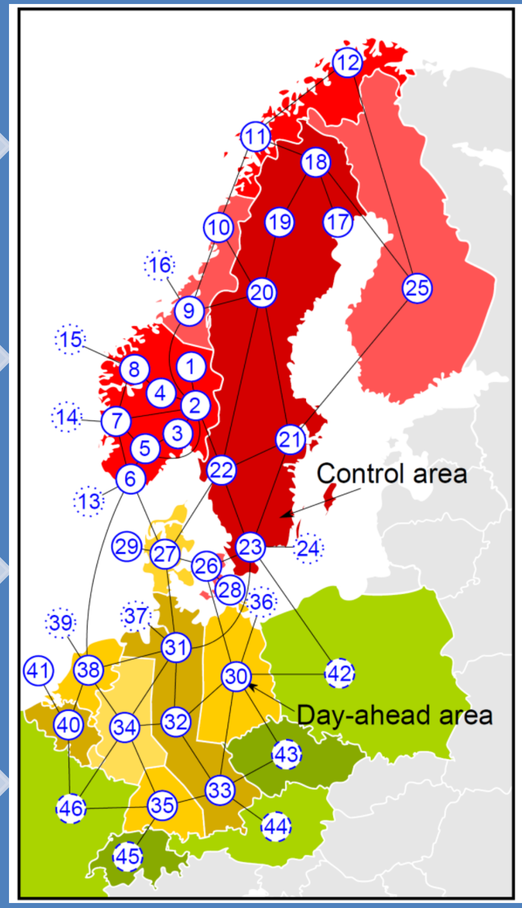
Study model 1 – Integration of balancing markets

Fundamental model
- Detailed water course description
- About 300 thermal power plants
- Transmission corridors (NTC)

Northern Europe
- Denmark, Finland, Norway, Sweden
- Germany, Netherlands, Belgium

System scenarios
- 2010 – current state of the system
- 2020 – a future state of the system

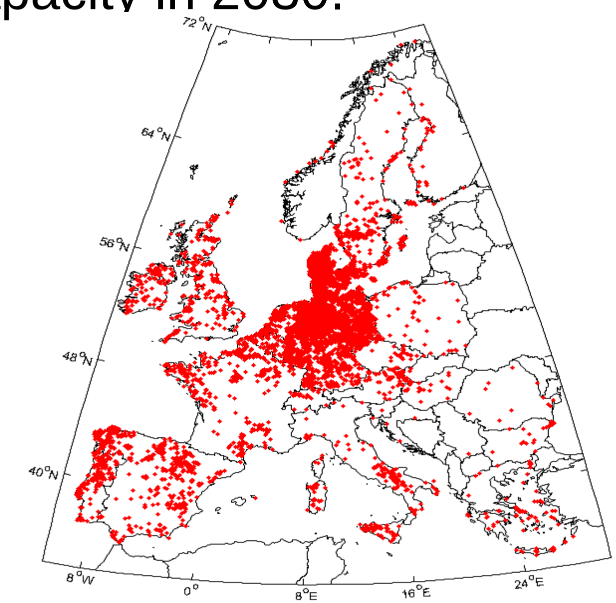
Several climatic years
- Hydrology (Inflow)
- Temperature
- Wind speed

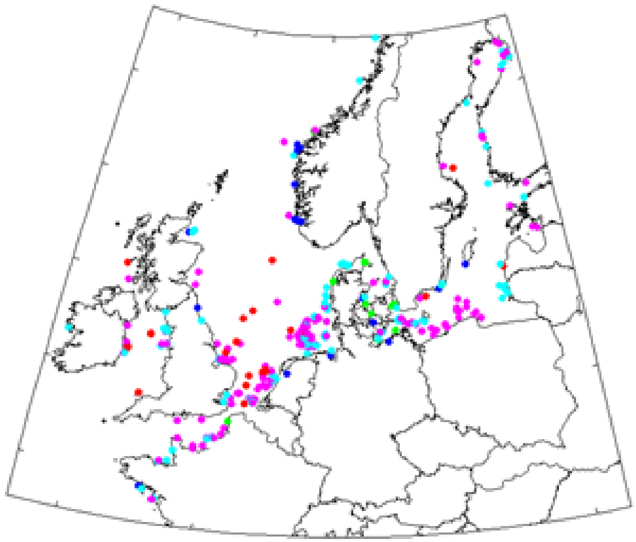


Source: Doorman (NTNU)

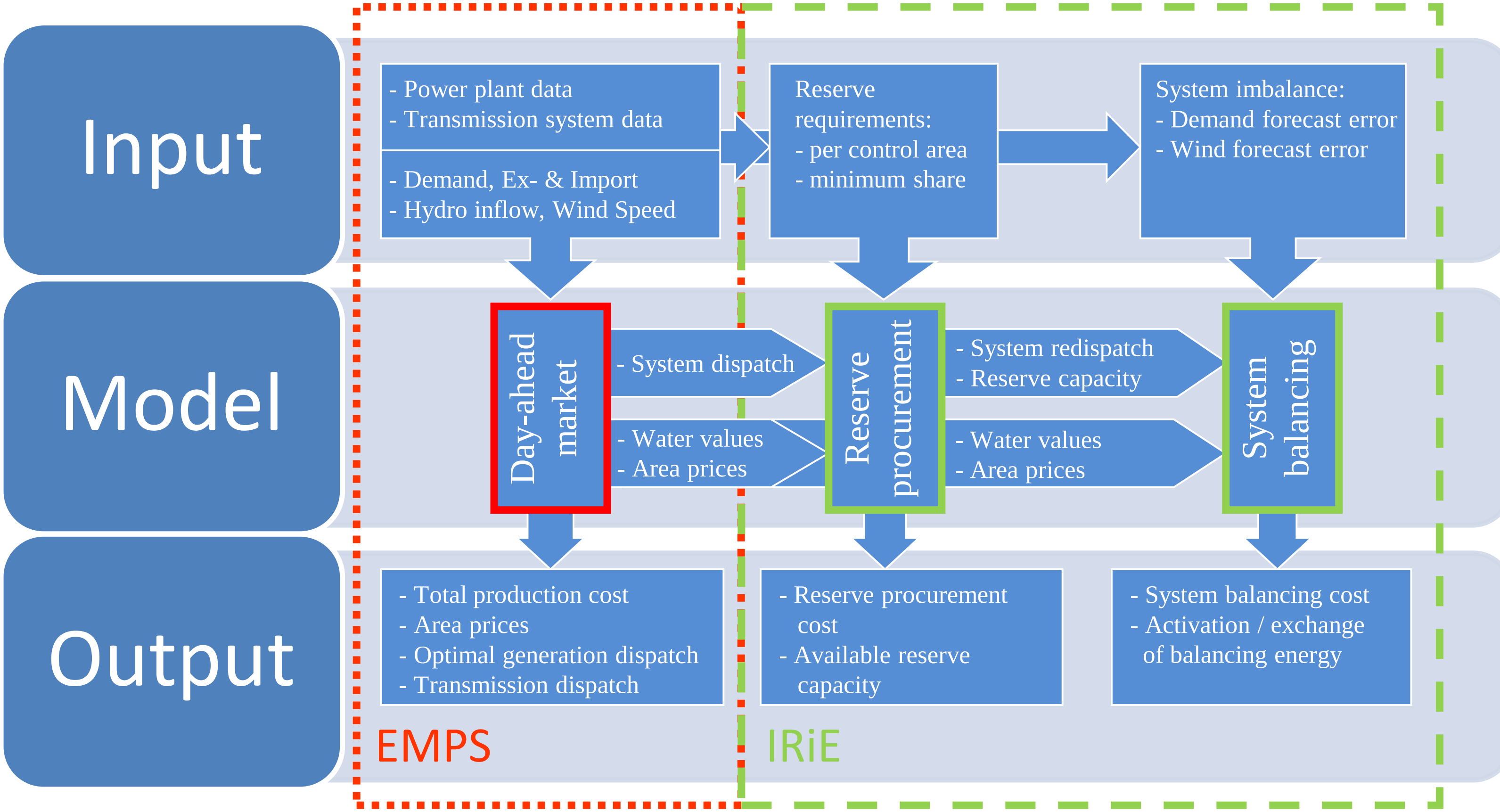
Time-series for wind power

- Wind speed model that is a combination of a numerical prediction model (COSMO EU) and wind speed measurements.
- Database covers 3500 wind facilities
- COSMO-EU includes detailed description of wind speed with a resolution of 7kmx7Km and 15 min
- The installed wind power capacity is scaled up to meet the assumed installed capacity in 2030.





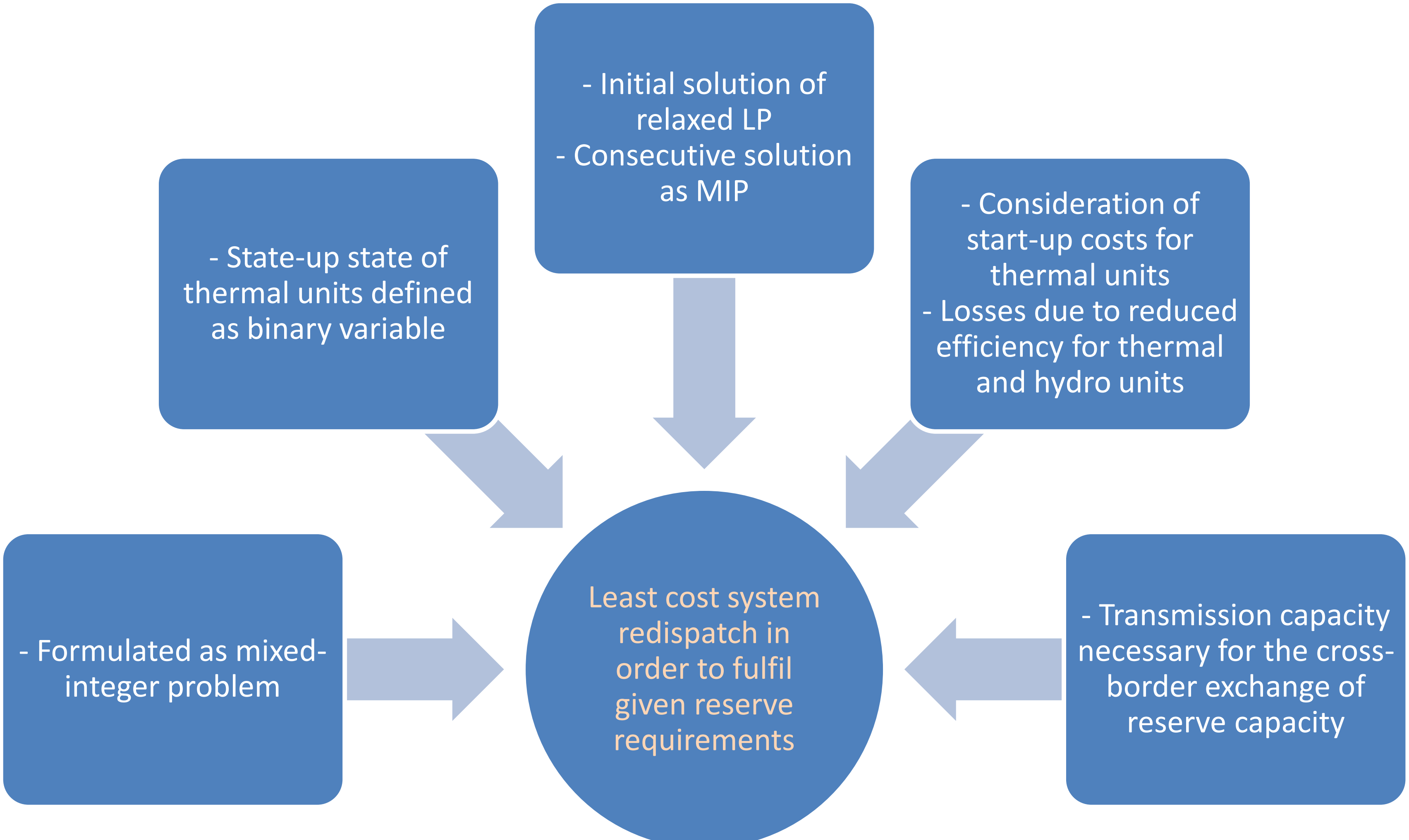
Market model structure



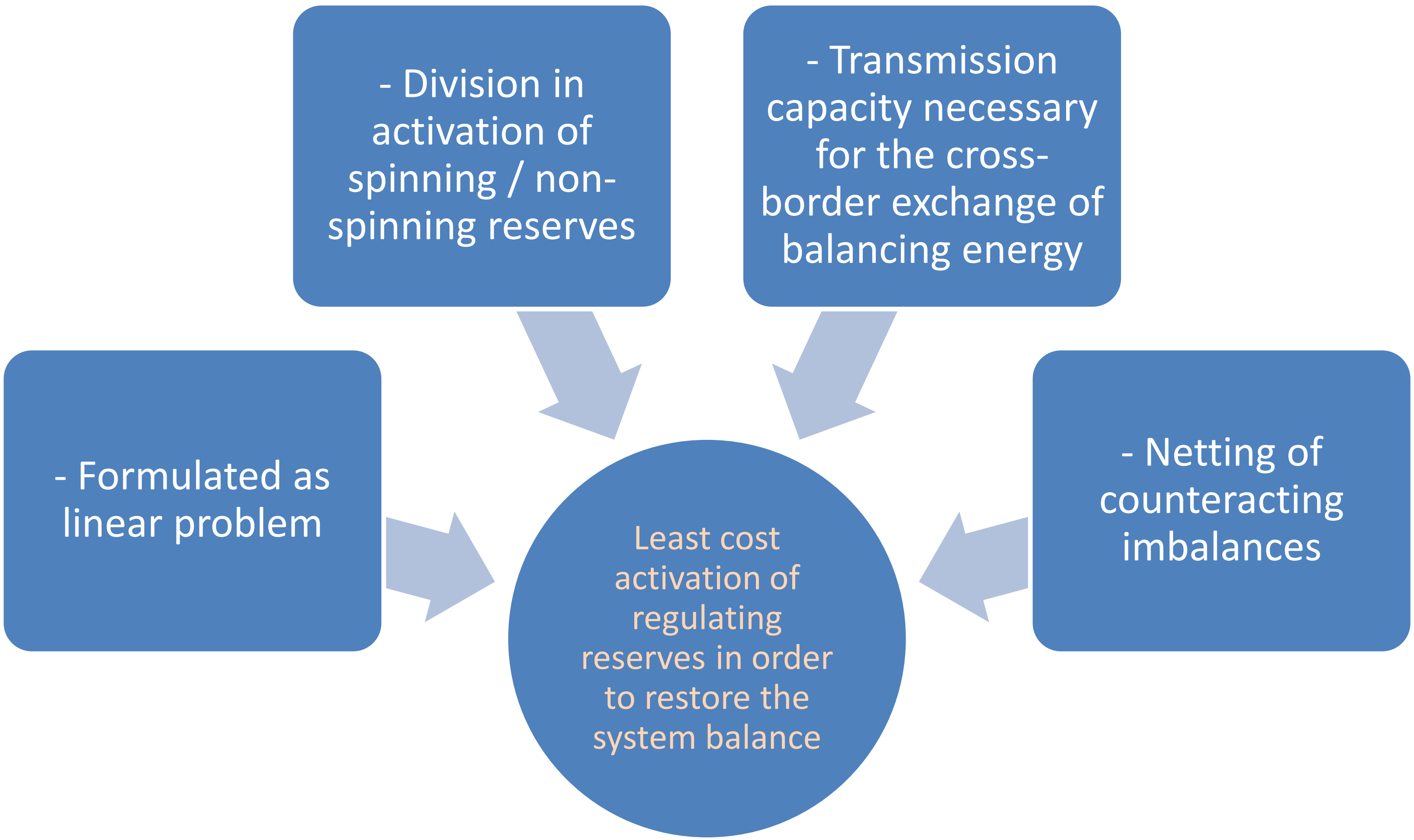
EMPS — EFI's Multi-area Power-market Simulator

IRiE — Integrated Regulating power market in Europe

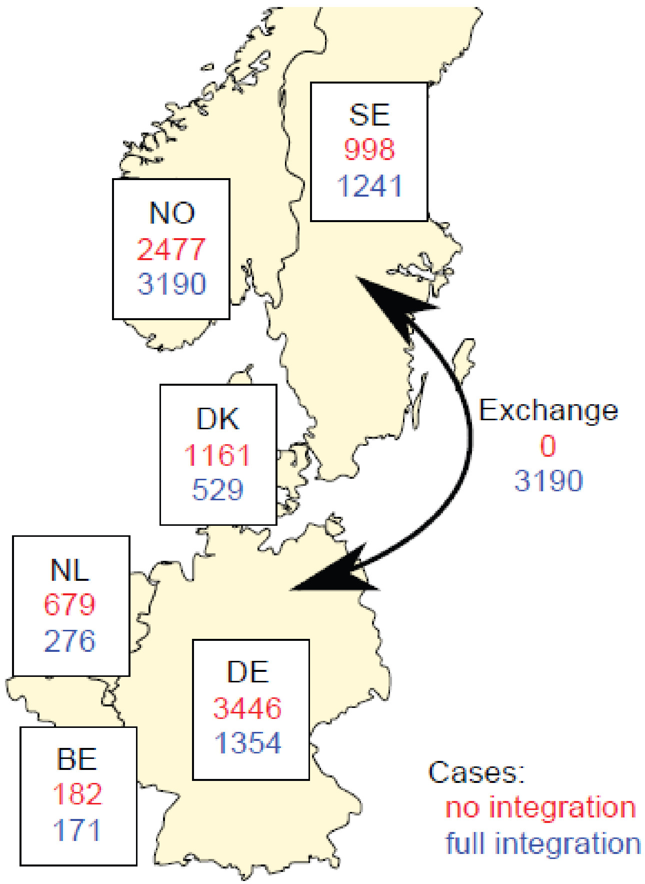
IRiE - Reserve procurement



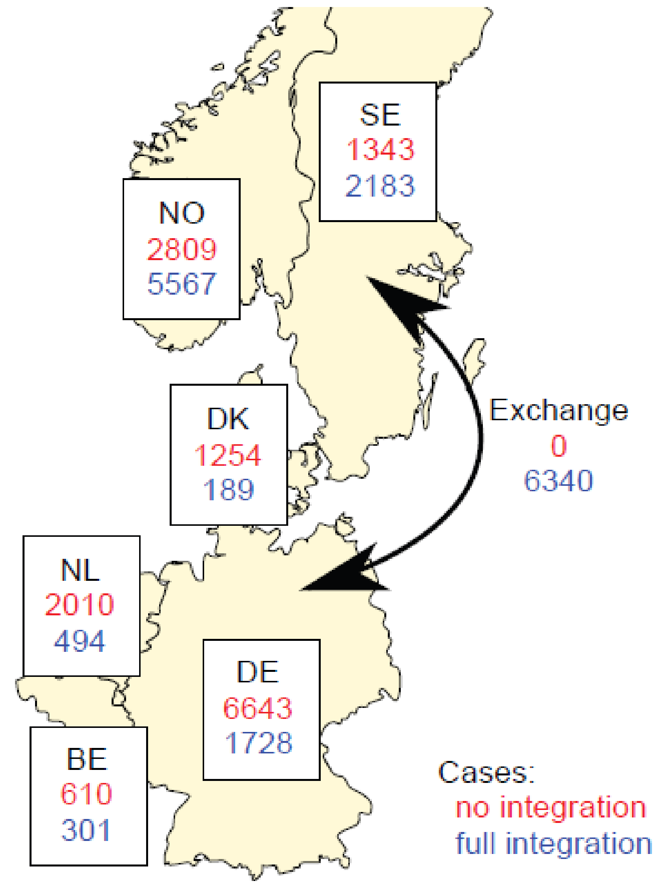
IRiE - System balancing



Country wise annual balancing reserve allocation (GWh/yr)



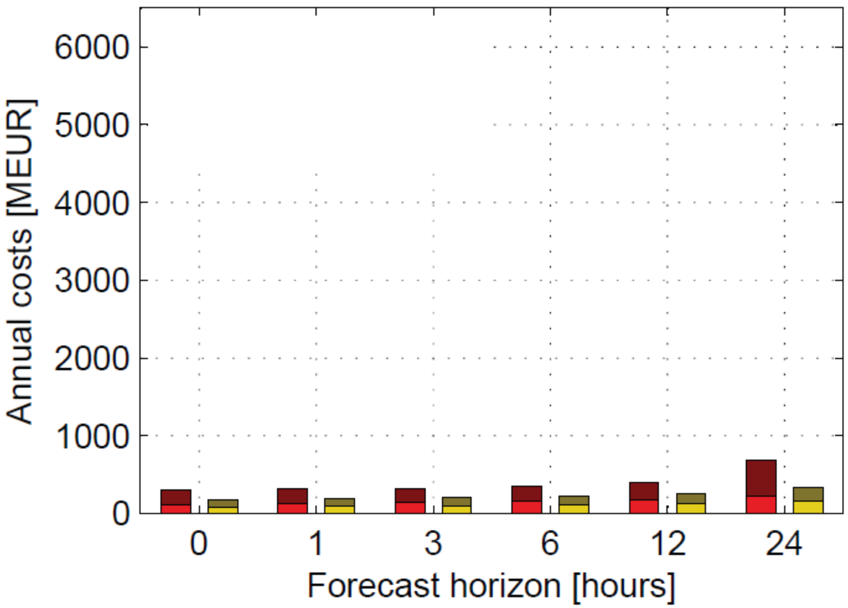
(a) 2010



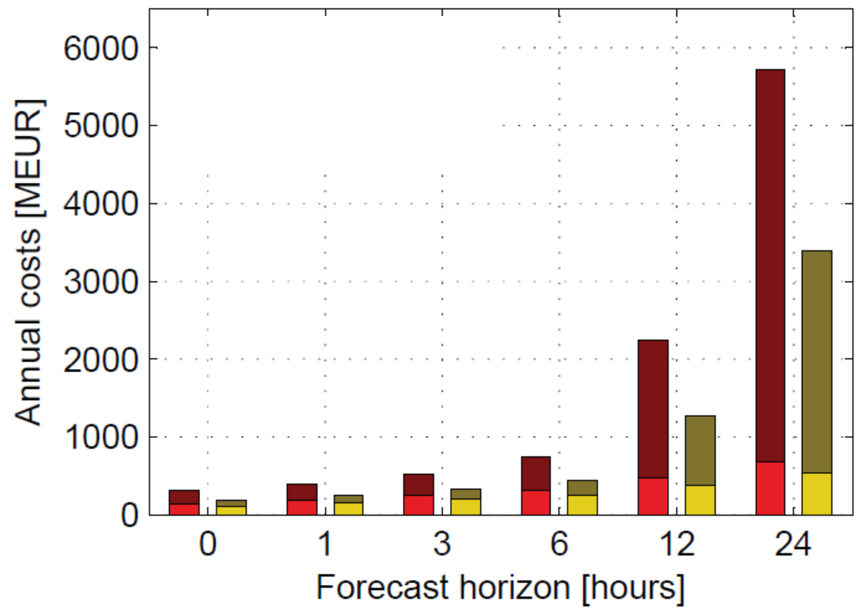
(b) 2020

Source: Jaehnert (NTNU)

Total balancing market costs for different wind forecast horizons



(a) 2010



(b) 2020

No integration : Reserve procurement
No integration : System balancing
Full integration: Reserve procurement
Full integration: System balancing

Source: Jaehnert (NTNU)

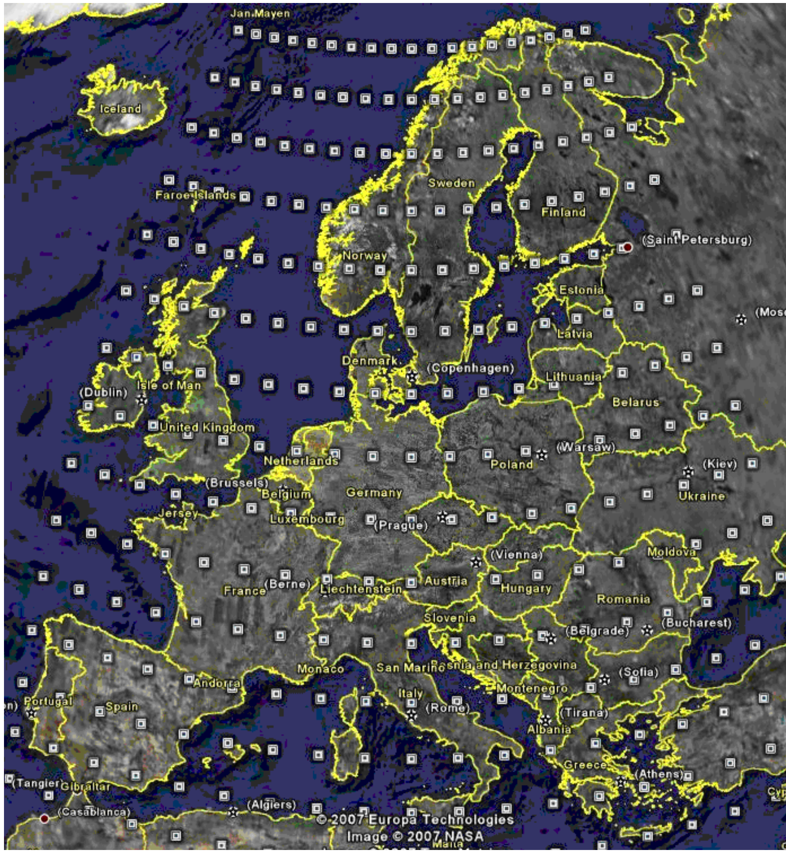
Study model 2 – Integration of balancing markets

- Detailed European grid model based on DC power flow
- Representation of day-ahead, intra-day and balancing markets
- Co-optimizating day-ahead scheduels and reserve procurements based on forecasts
- Scenarios for load, generation and grid capacity year 2020 and 2030

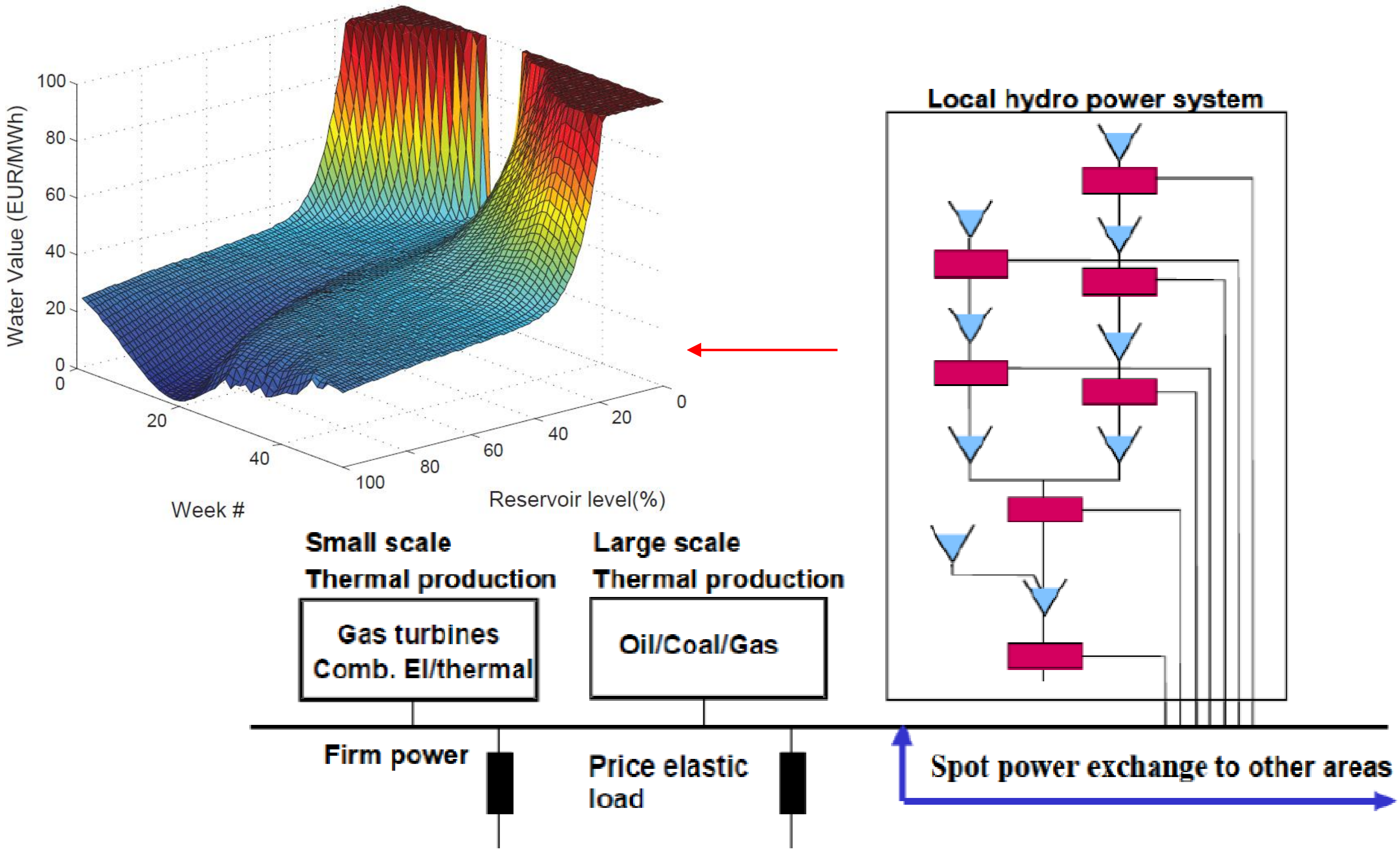
Source: Farahmand (NTNU/SINTEF)

Power System Simulation Tool

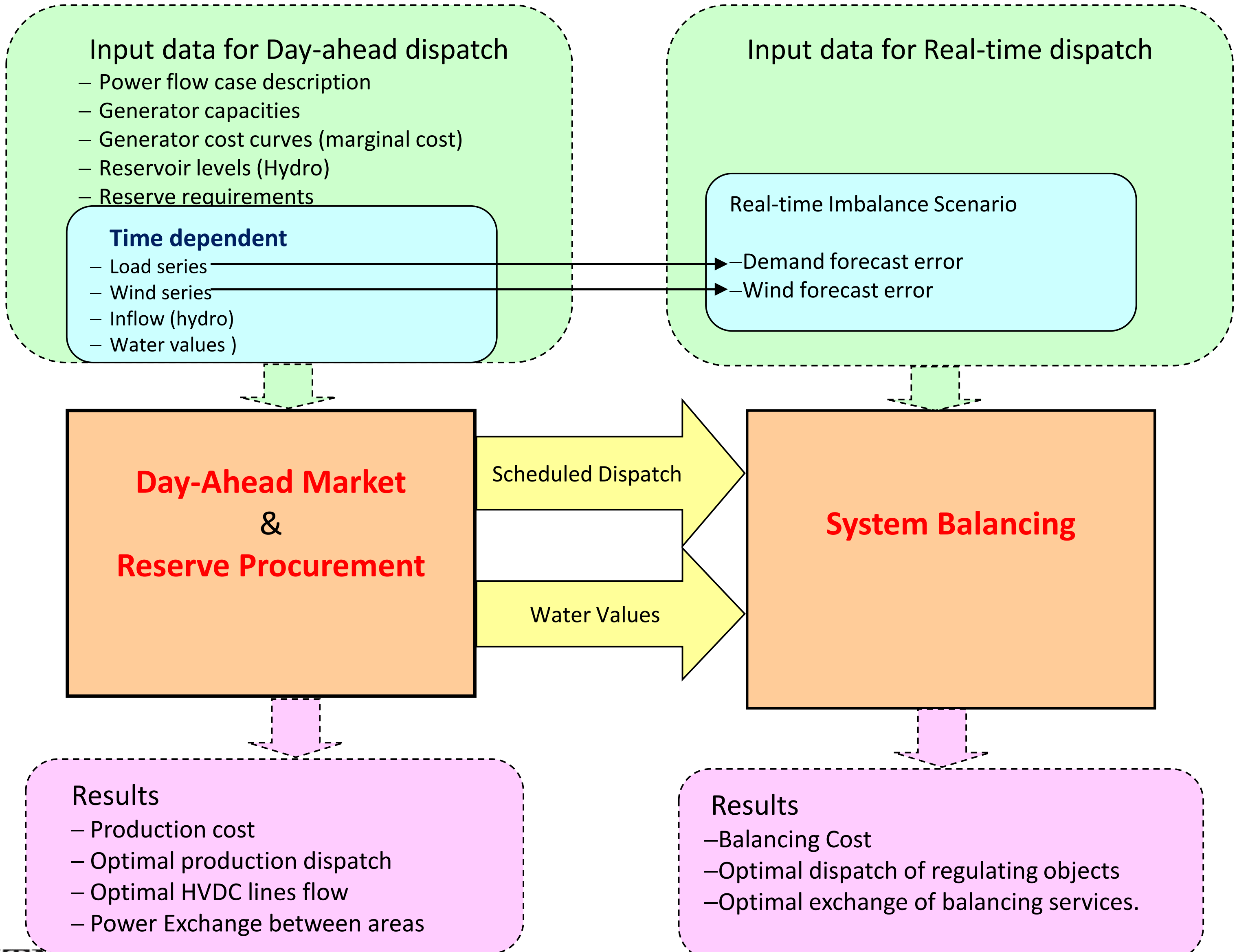
- ***Time series simulation model*** of main transmission, generation and load (for scenario years 2015, 2020, 2030 combined with +3 wind variants)
- ***Input*** time series of wind speed & load demand (1 hour resolution)
- ***Market model*** to compute power balances and prices. Simple marginal costs of generation. Water values from the EMPS model.
- ***Network model:*** DC optimal power flow with 1400 nodes, 2220 branches (+56 HVDC), 540 generators + wind farms



Strategic Usage of Hydro



Simulation Procedure



Approach: How to Model Day-ahead Market?

The objective is to minimise the successive 24-h of system operating cost.

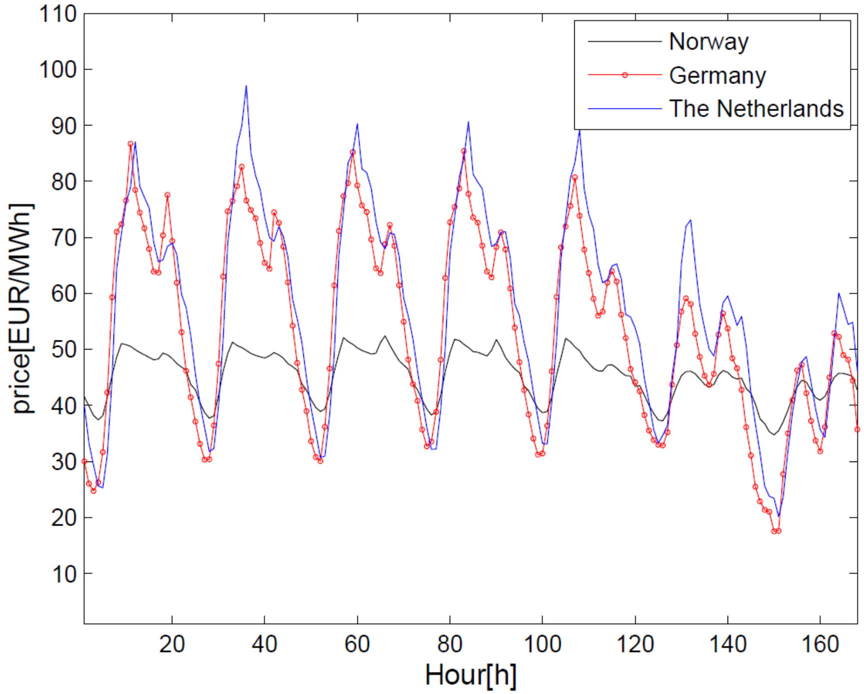
Balancing reserves are procured for both up- and downward regulating simultaneously with day-ahead dispatch.

An LP based algorithm is implemented to model start-up cost.

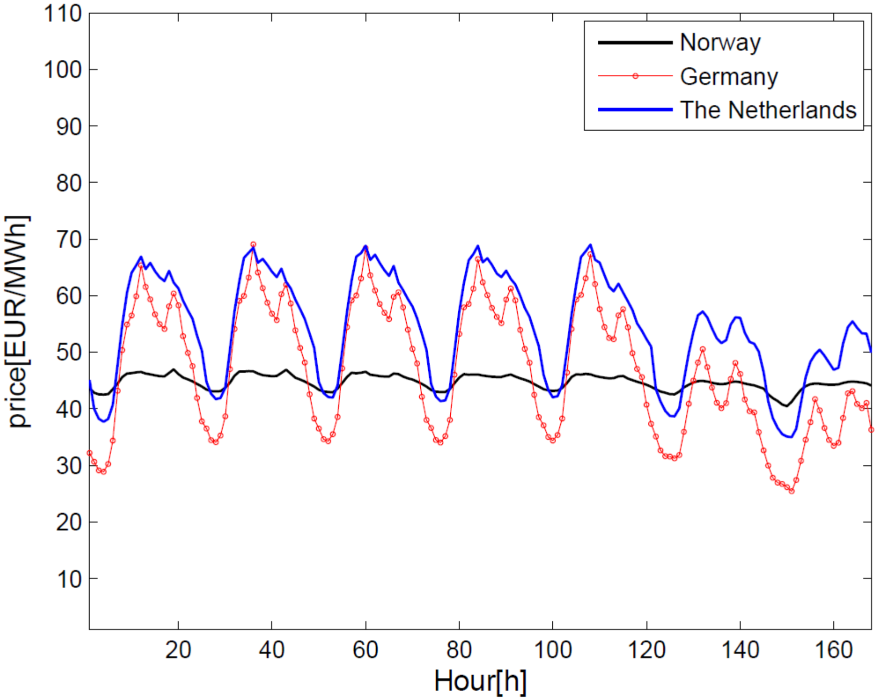
- Thermal Generators ➡ spinning reserve is considered start-up cost is regarded
- Hydro ➡ start-up cost is neglected

Available transmission capacity is taken into account in cross-border reserve procurement.

Average weekly spot price



Recorded price



Simulated Price

Approach: How to Model System Balancing?

The aim is to activate the necessary reserve to retain the system balance while minimising balancing cost.

Imbalance scenarios include the load forecast error and wind forecast error.

Balancing resources are the reserve procured in day-ahead dispatch.

The cross-border balancing energy is transmitted through the remaining capacity from day-ahead dispatch.

Case Studies

Case I

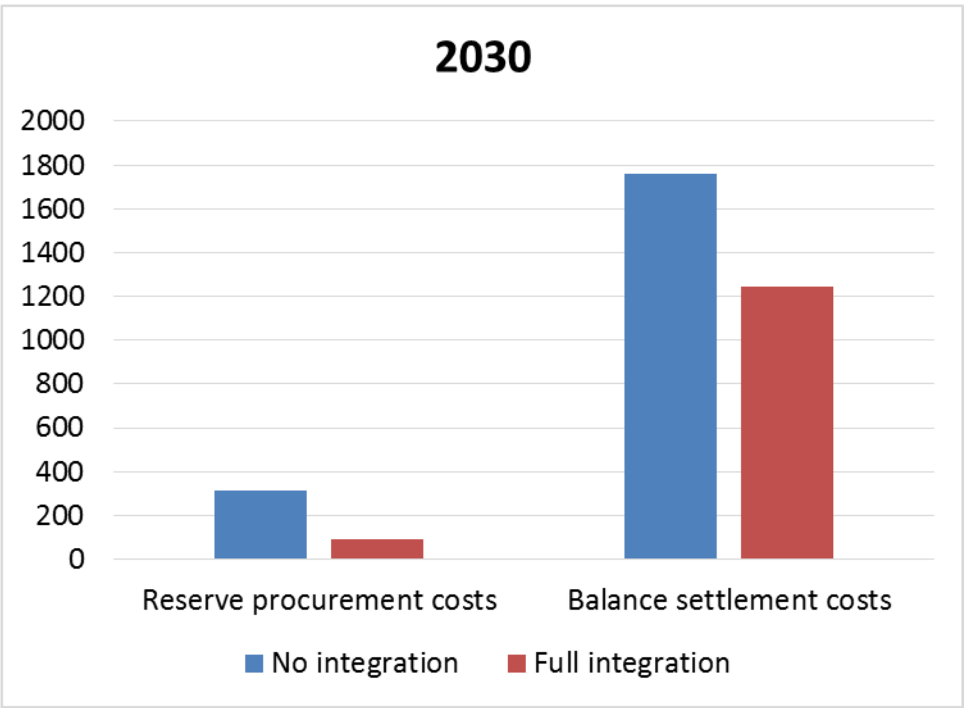
It is the reference case and represents the current state of the system.

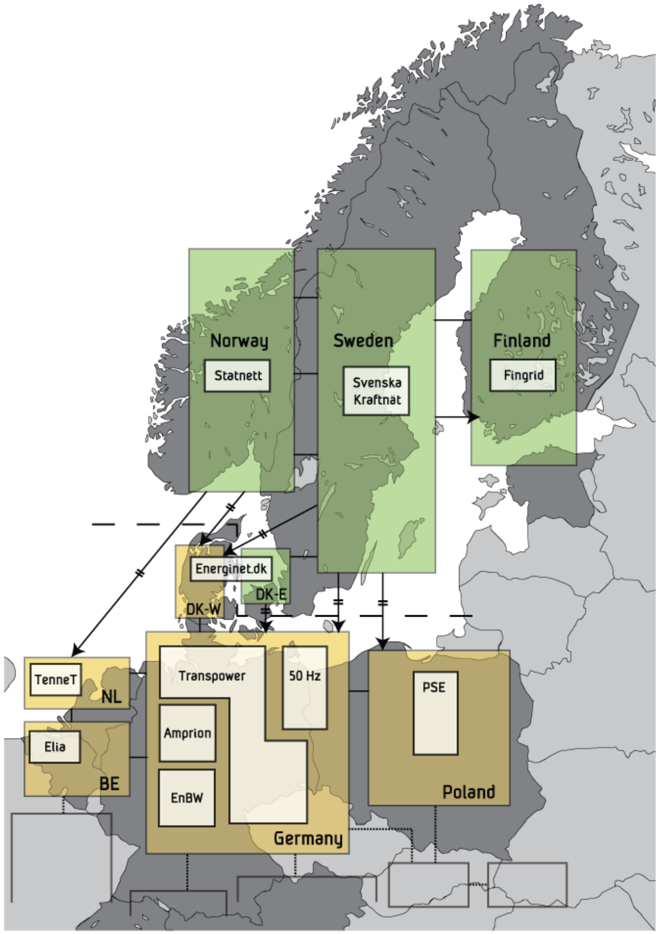
Case II

It represents full integration of the balancing markets in Northern Europe where balancing services can be exchanged system-wide.

Large benefits of integrating the Northern and continental balancing markets

Total annual balancing costs (Mill.EURO)

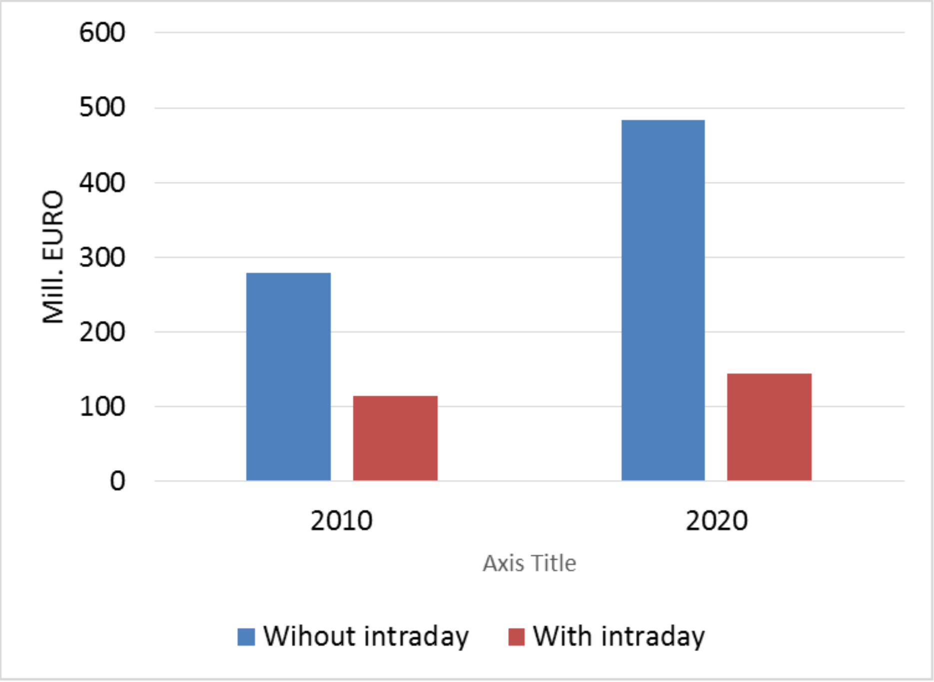




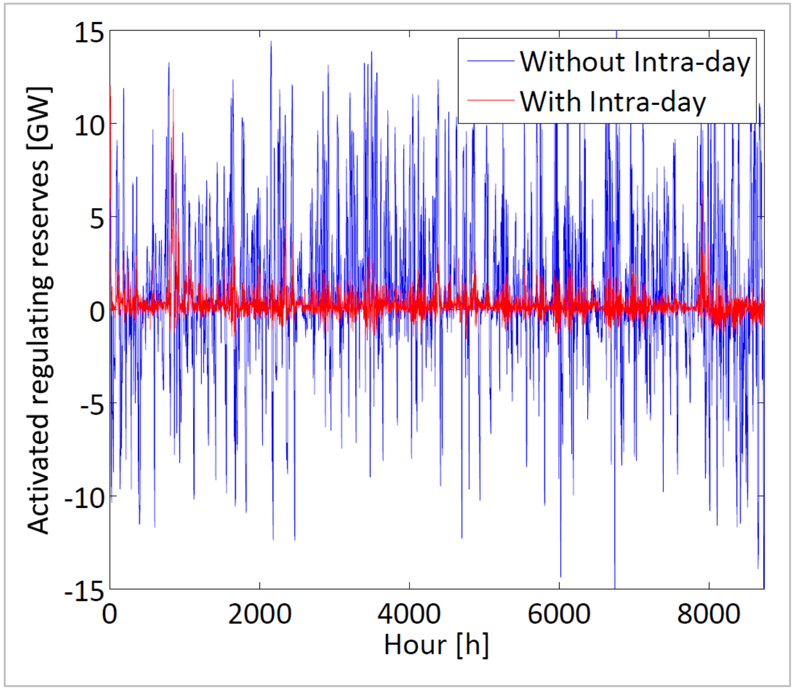
Source: Farahmand (NTNU/SINTEF)

Significant savings are achieved with integrated intra-day markets

Total annual balancing costs

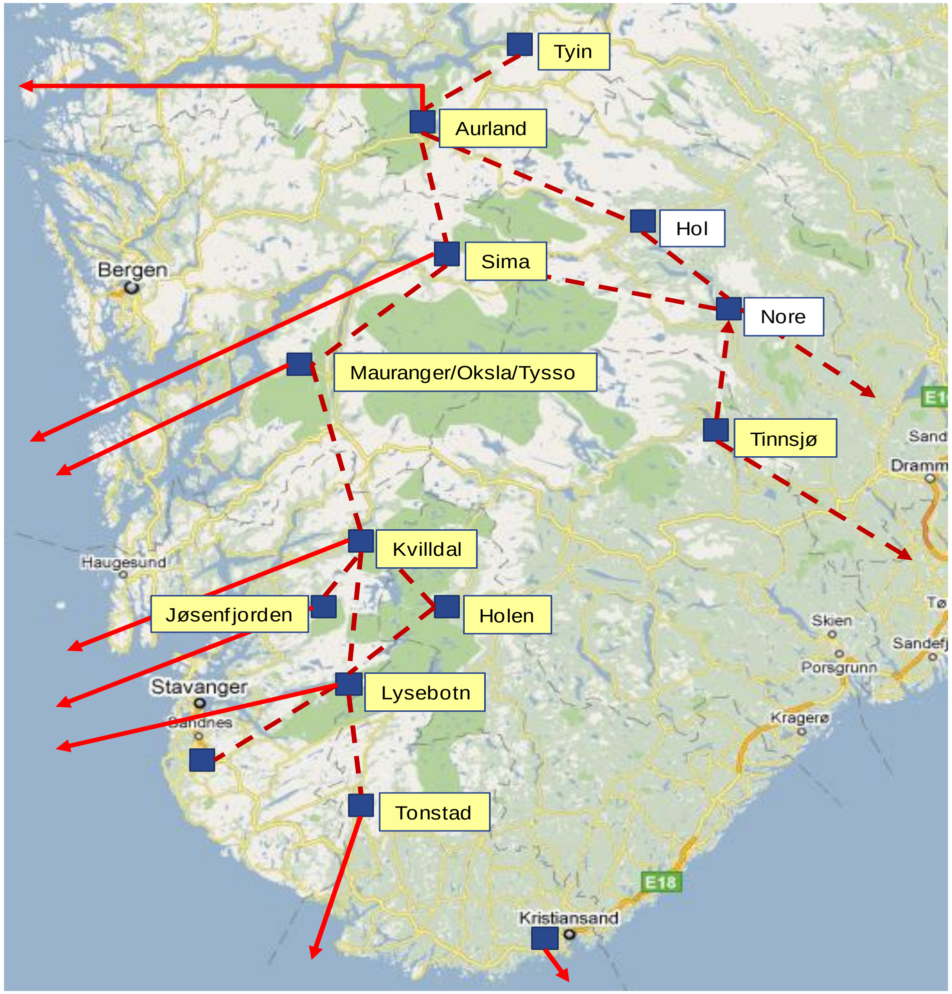


Activated reserves



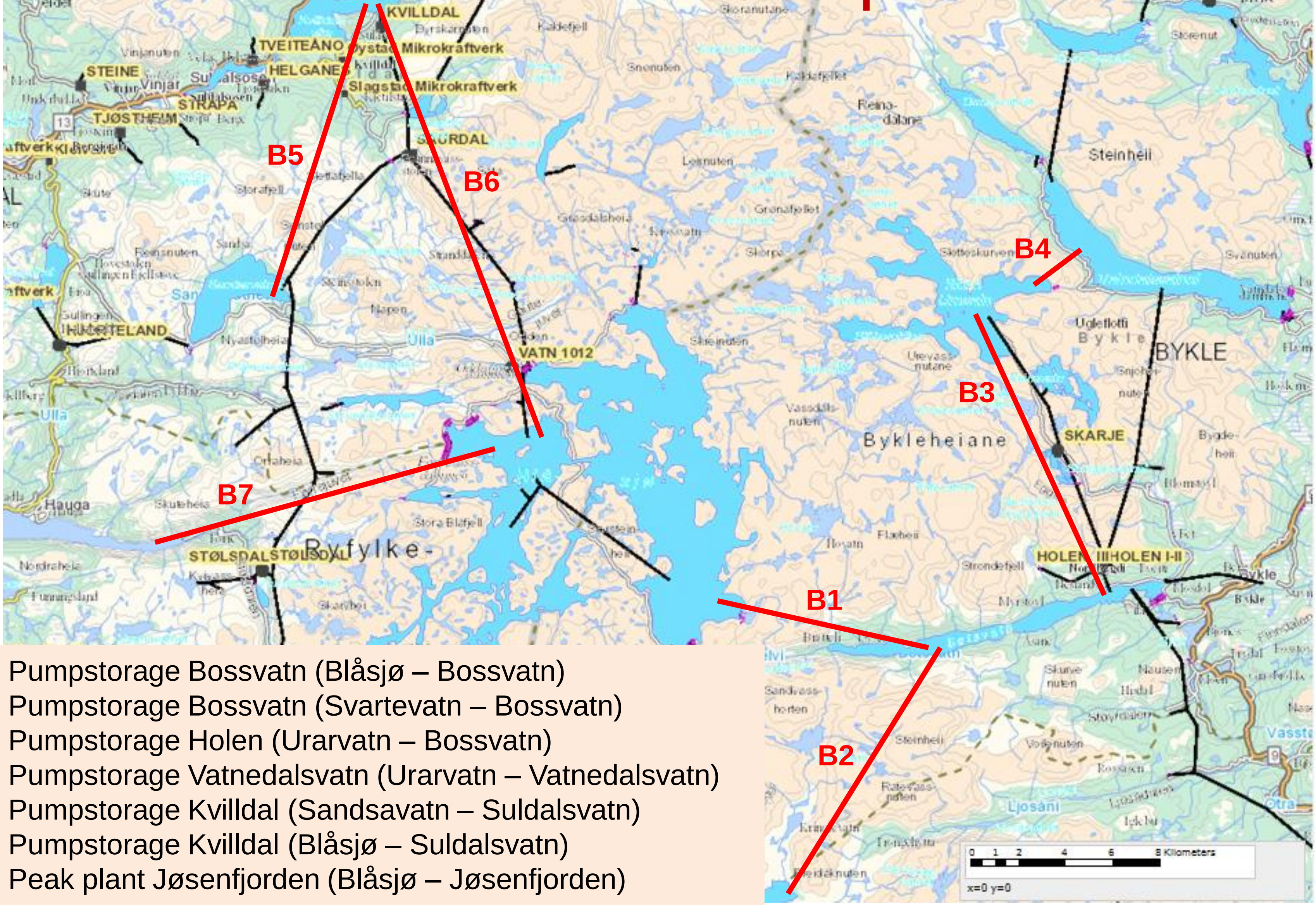
Source: Aigner (NTNU)

CEDREN Balancing potential study 2030

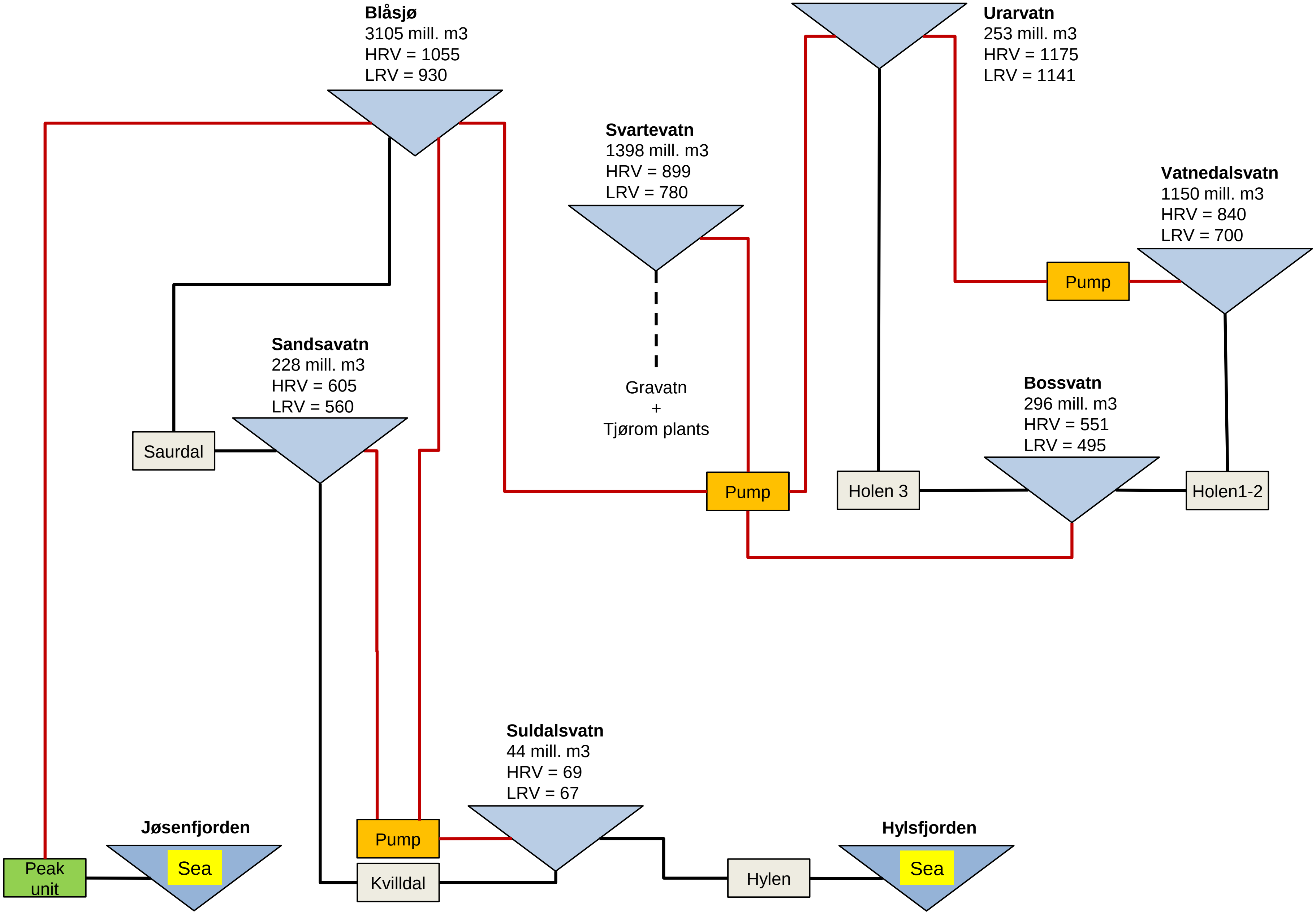


- 20 000 MW new pumping capacity in southern Norway
- Export of balancing services
- Integration of grids & markets

Technical potential



B1 Pumpstorage Bossvatn (Blåsjø – Bossvatn)
B2 Pumpstorage Bossvatn (Svartevatn – Bossvatn)
B3 Pumpstorage Holen (Urarvatn – Bossvatn)
B4 Pumpstorage Vatnedalsvatn (Urarvatn – Vatnedalsvatn)
B5 Pumpstorage Kvilldal (Sandsavatn – Suldalsvatn)
B6 Pumpstorage Kvilldal (Blåsjø – Suldalsvatn)
B7 Peak plant Jøsenfjorden (Blåsjø – Jøsenfjorden)



Blåsjø
3105 mill. m3
HRV = 1055
LRV = 930
Urarvatn
253 mill. m3
HRV = 1175
LRV = 1141
Svartevatn
1398 mill. m3
HRV = 899
LRV = 780
Vatnedalsvatn
1150 mill. m3
HRV = 840
LRV = 700
Pump
Sandsavatn
228 mill. m3
HRV = 605
LRV = 560
Gravatn
+
Tjørom plants
Bossvatn
296 mill. m3
HRV = 551
LRV = 495
Saurdal
Pump
Holen 3
Holen1-2
Suldalsvatn
44 mill. m3
HRV = 69
LRV = 67
Jøsenfjorden
Hylsfjorden
Pump
Peak unit
Sea
Kvilldal
Hylen
Sea

Scenario 12 new power plants

Case	Kraftverk	Kapasitet (MW)	Øvre magasin[1]		Nedre magasin[2]	
A2	Pumpekraftverk Tonstad	1 400	Nesjen	(14 cm/h)	Sirdalsvatn	(3 cm/h)
B3	Pumpekraftverk Holen	700	Urarvatn	(8 cm/h)	Bossvatn	(8 cm/h)
B6a	Pumpekraftverk Kvilldal	1 400	Blåsjø	(7 cm/h)	Suldalsvatn	(4 cm/h)
B7a	Effektverk Jøsenfjorden	1 400	Blåsjø	(7 cm/h)	Jøsenfjorden	(sjø)
C1	Pumpekraftverk Tinnsjø	1 000	Møsvatn	(2 cm/h)	Tinnsjø	(1 cm/h)
D1	Effektverk Lysebotn	1 400	Lyngsvatn	(9 cm/h)	Lysefjorden	(sjø)
E1	Effektverk Mauranger	400	Juklavatn	(14 cm/h)	Hardangerfj.	(sjø)
E2	Effektverk Oksla	700	Ringedalsvatn	(12 cm/h)	Hardangerfj.	(sjø)
E3	Pumpekraftverk Tysso	700	Langevatn	(9 cm/h)	Ringedalsvatn	(7 cm/h)
F1	Effektverk Sy-Sima	700	Sysenvatn	(9 cm/h)	Hardangerfj.	(sjø)
G1	Effektverk Aurland	700	Viddalsvatn	(12 cm/h)	Aurlandsfj.	(sjø)
G2	Effektverk Tyin	700	Tyin	(1 cm/h)	Årdalsvatnet[3]	
	Sum ny effektkapasitet	11 200				

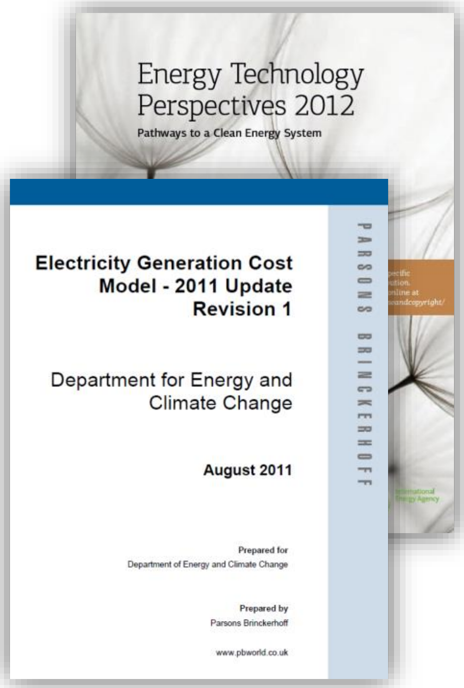
[1]Vannstandsreduksjon i parentes.

[2]Vannstandsøkning i parentes.

[3]Mangler data for å beregne vannstandsøkning i Årdalsvatnet.

Overview of study

- Only cost is considered
  - Market operation “translated” to load factors
  - Assessment of the most cost-effective flexibility options in the near term
- Input data
  - Time period 2030-2040
  - Based on IEA WEO scenarios and figures
  - Gas plant models and costs according to report for UK Dept. of Energy and Climate Change
  - Pumped hydro storage and grid data based on Norwegian figures; Producers, Regulator, TSO, Univ.

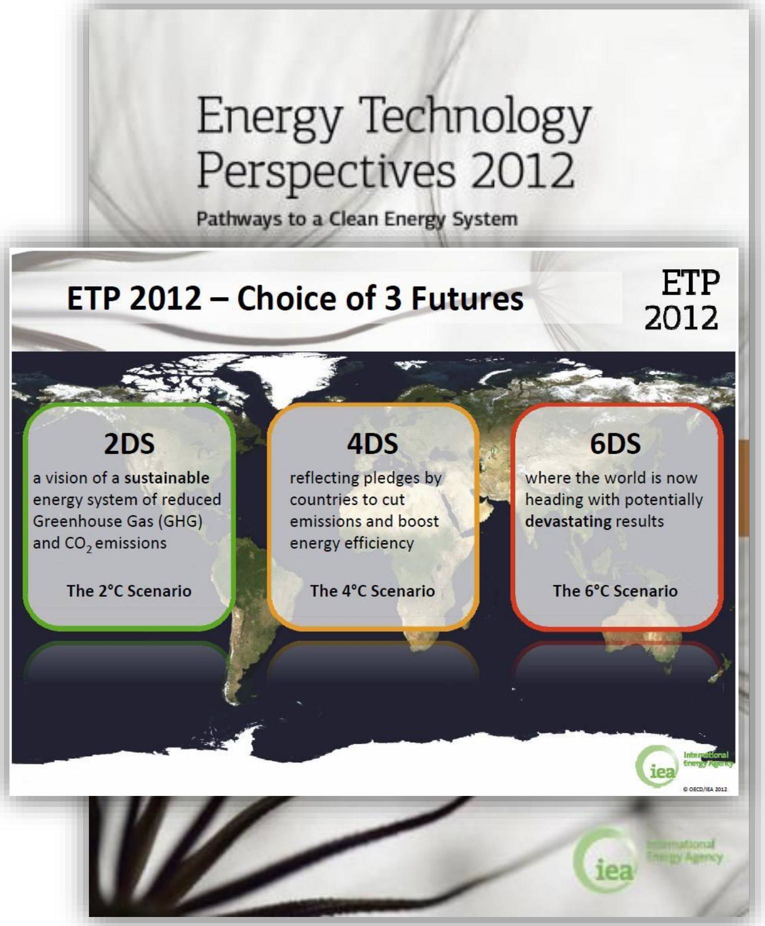


Three scenarios
2025 – 2050 perspective

1. 2DS – IEA 450 Scenario:
   - Gas price 29.5 € /MWh
   - CO_2 price 93.9 €/ton

2. 4DS – IEA New Policy Scenario:
   - Gas price 34.8 €/MWh
   - CO_2 price 35.2 €/ton

3. Low Gas price Europe:
   - Gas price 19.7 €/MWh (USA level)
   - CO_2 price 35.2 €/ton (as 4DS)



Levelised Cost of Electricity (LCOE)

$$LCOE = \frac{\text{Discounted total investment costs and variable costs}}{\text{Discounted total generation}}$$

- Treating all years equal
- Only initial investments

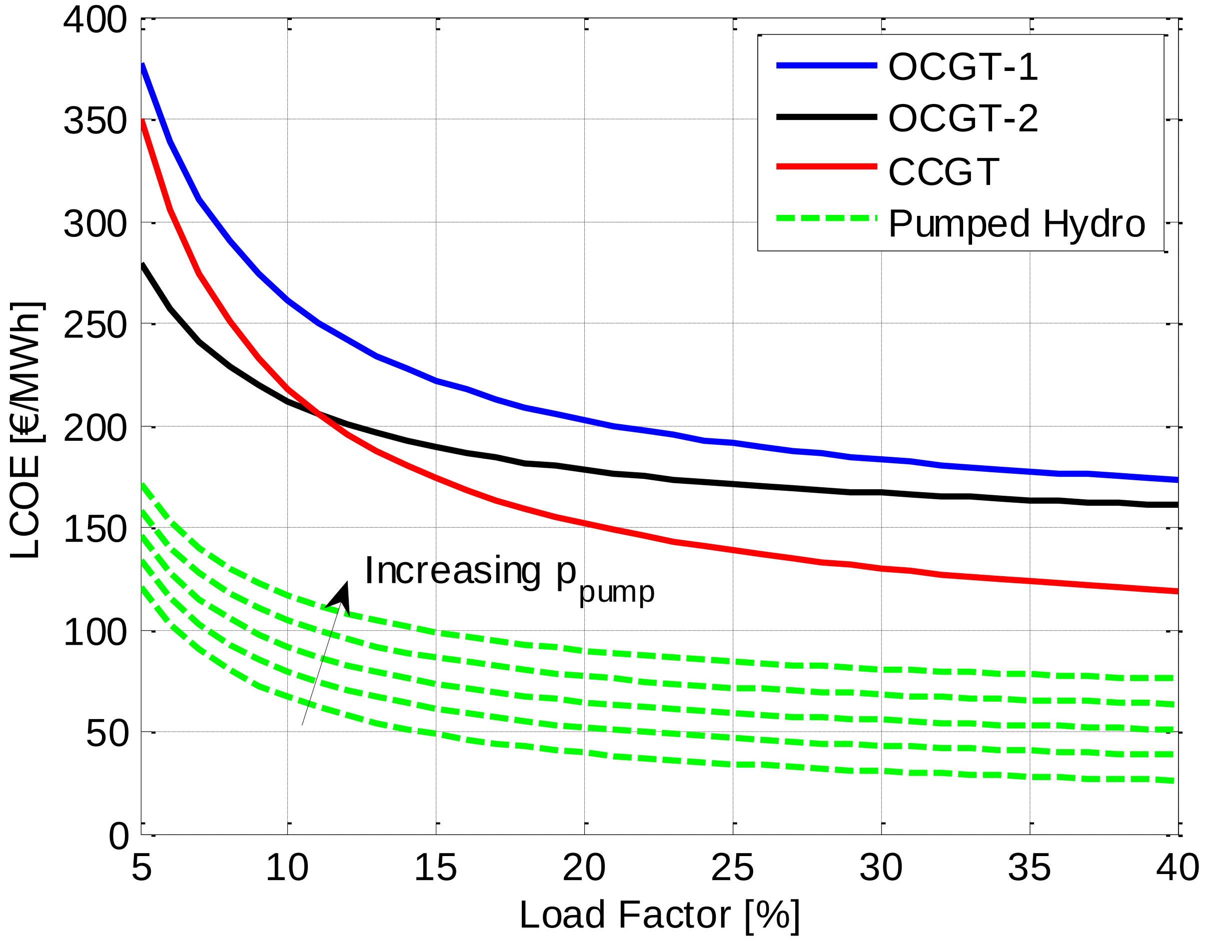
$$LCOE = \frac{\text{Specific InvCost} \cdot (\text{AnnuityFactor} + \text{O\&Mpct})}{\text{Availability} \cdot \text{FullLoadHours}} + \sum \text{VariableCosts}$$

$$LCOE = \frac{i \cdot (\delta_{n,r} + OM)}{\alpha \cdot T_{fl}} + \sum_{j=1}^{J} c_{var,j}$$

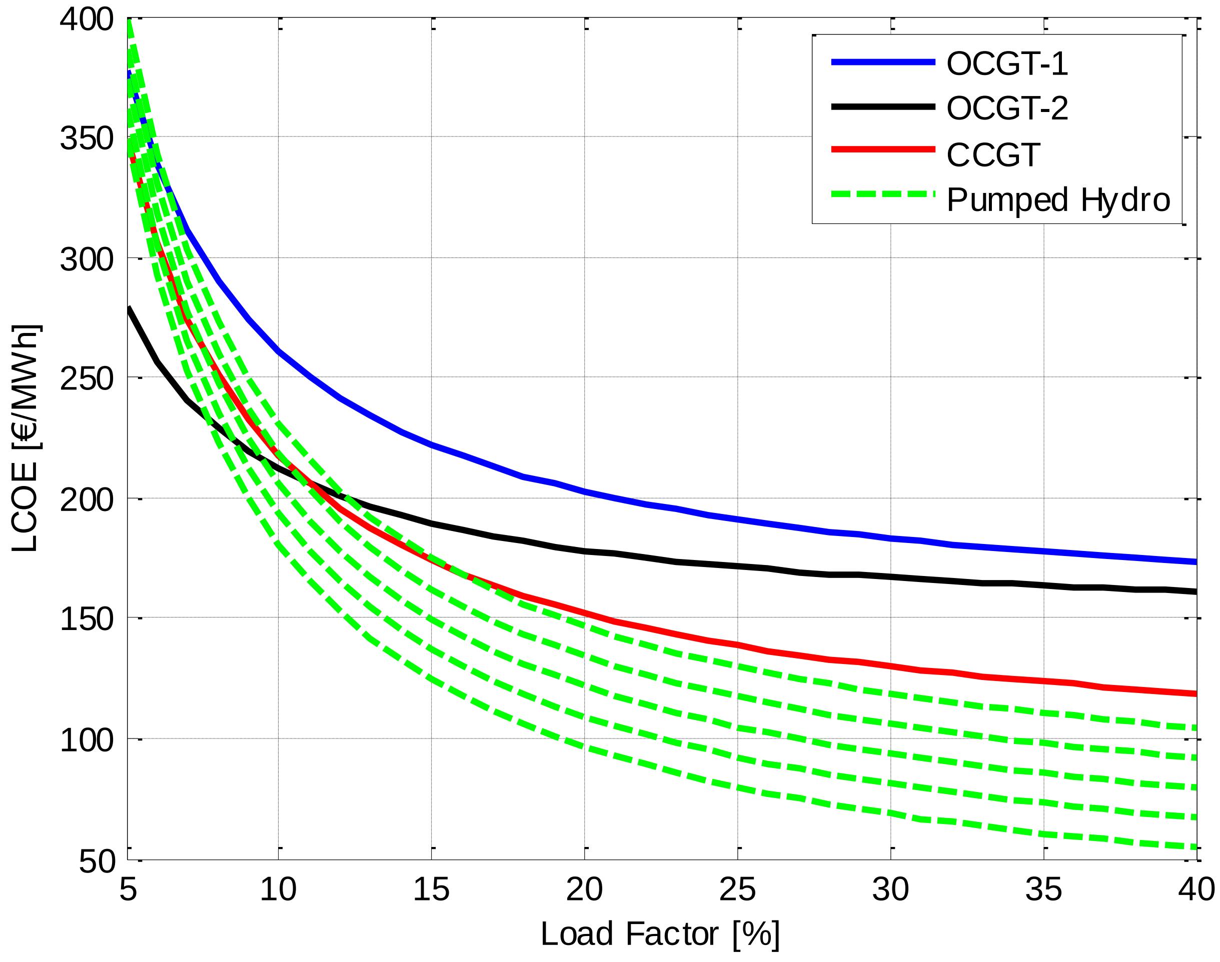
Natural gas → $(p_{ng} + p_{CO_2} \cdot e_{ng})/\eta_{ng}$

Pumped hydro → p_{pump}/η_{ph}

Norwegian pumped hydro has a relatively low LCOE…



…even when grid and cable costs are included



Levelised Cost of Peak Generation (LCPG)

- A proposed new metric for *the cost of providing electricity when fluctuating renewables and inflexible thermal generation cannot meet the (fixed) demand*
  - Peak generation must cover the residual load
- In this paper, we use fixed scenarios for capacity prices, and calculate the needed payment for delivered energy.
  - Flexible demand not considered in the specific case study, but can be treated equally

Natural gas: $$LCPG_{ng} = \frac{i_{ng} \cdot (\delta_{n_{ng},r} + OM_{ng}) - p_{cap}}{\alpha_{ng} \cdot T_{ng}} + \frac{\left(p_{ng} + p_{CO_2} \cdot e_{ng}\right)}{\eta_{ng}}$$

LCPG for pumped hydro

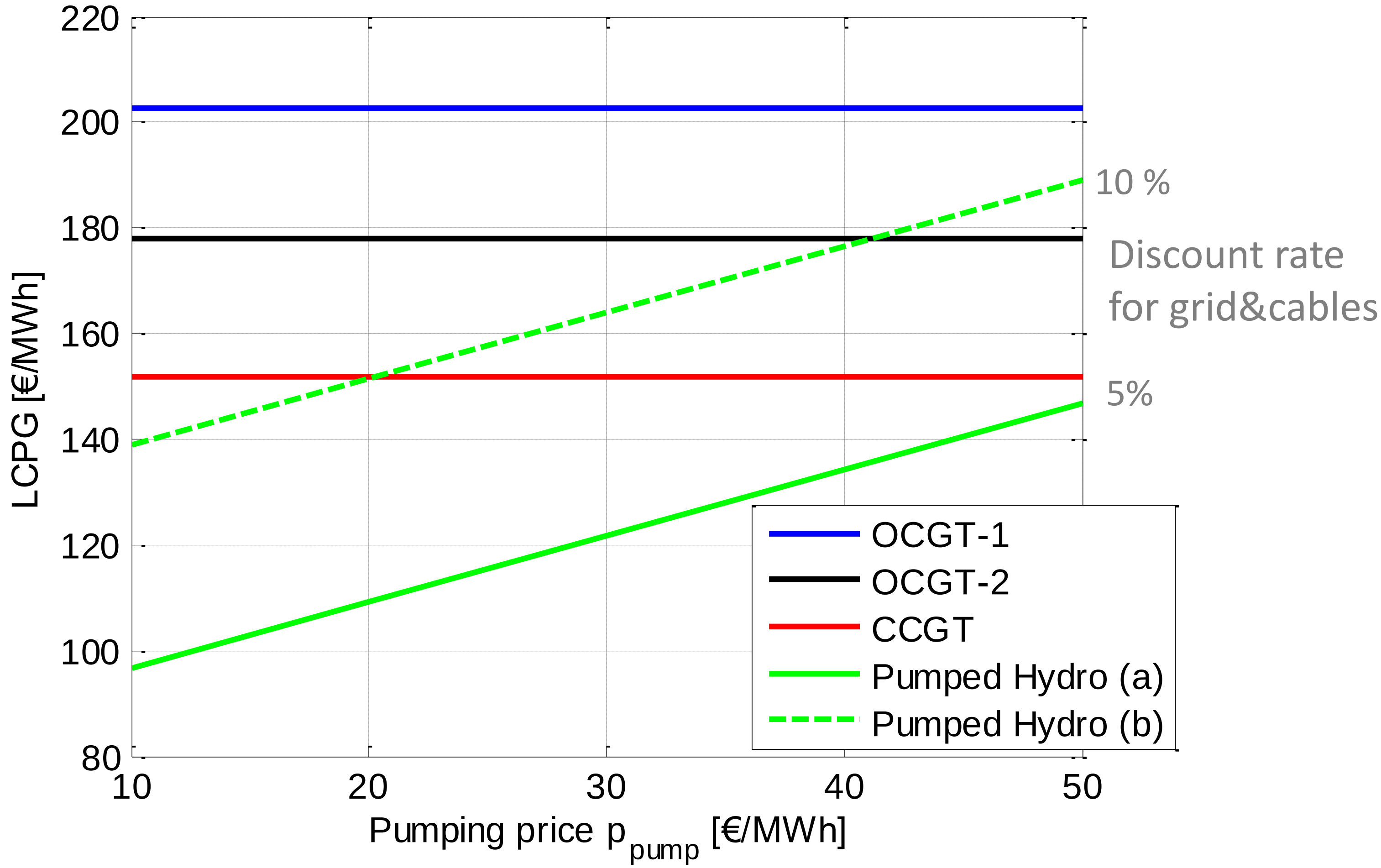
- Peak generation must cover the residual load
  - This is the basis for the cost comparison
- In addition, pumped hydro can be used for price leverage the rest of the year
  - Dependent on relative price variations vs storage efficiency
  - Dependent on plant characteristics and storage volumes
  - Dependent on production planning methods

Peaking Full Load Hours $T_{ph,peak} = T_{ng}$

Total Full Load Hours $T_{ph} \geq T_{ph,peak}$

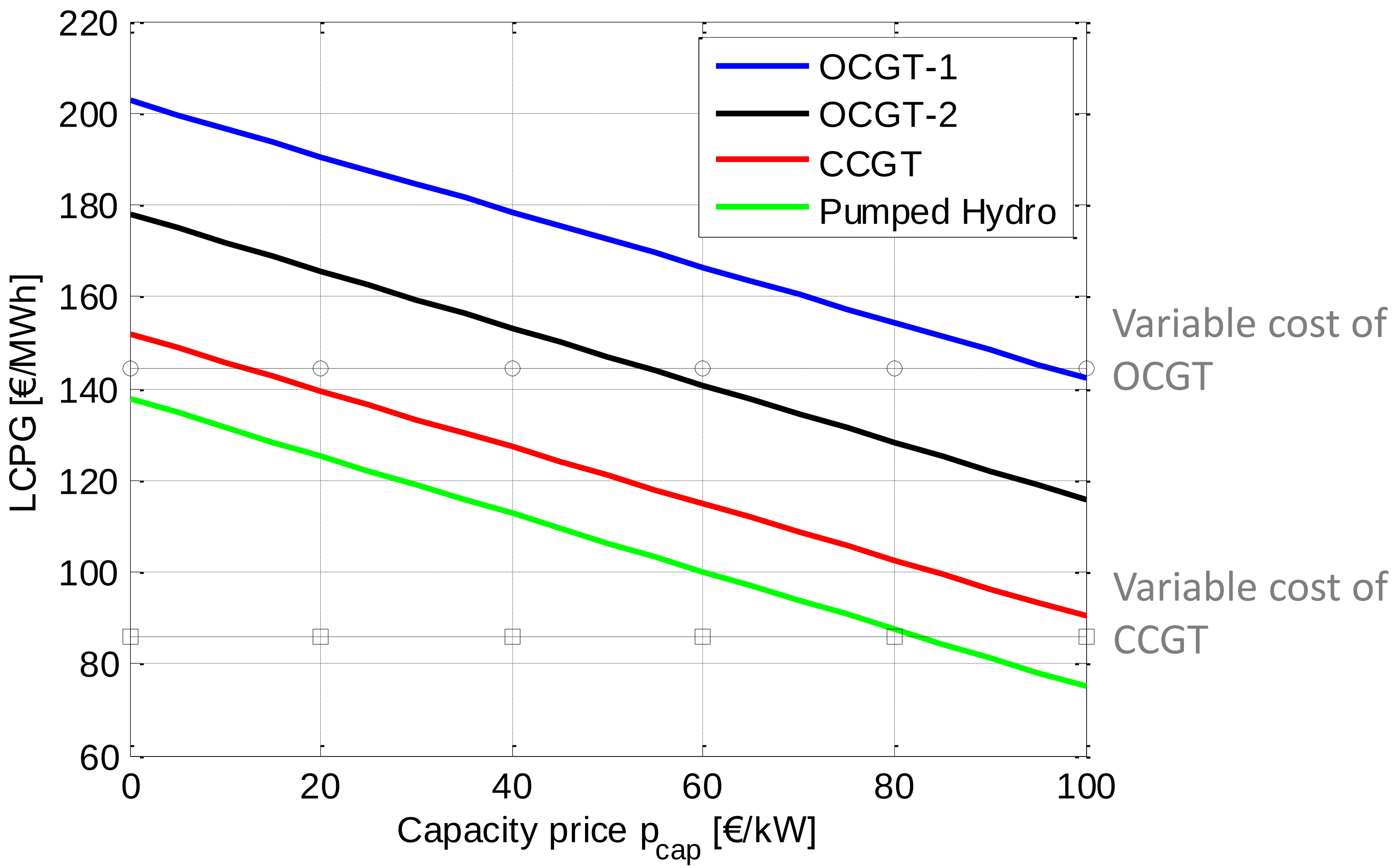
LCPG for 20 % load factor

Sensitivity on pumping price and cable discount rate



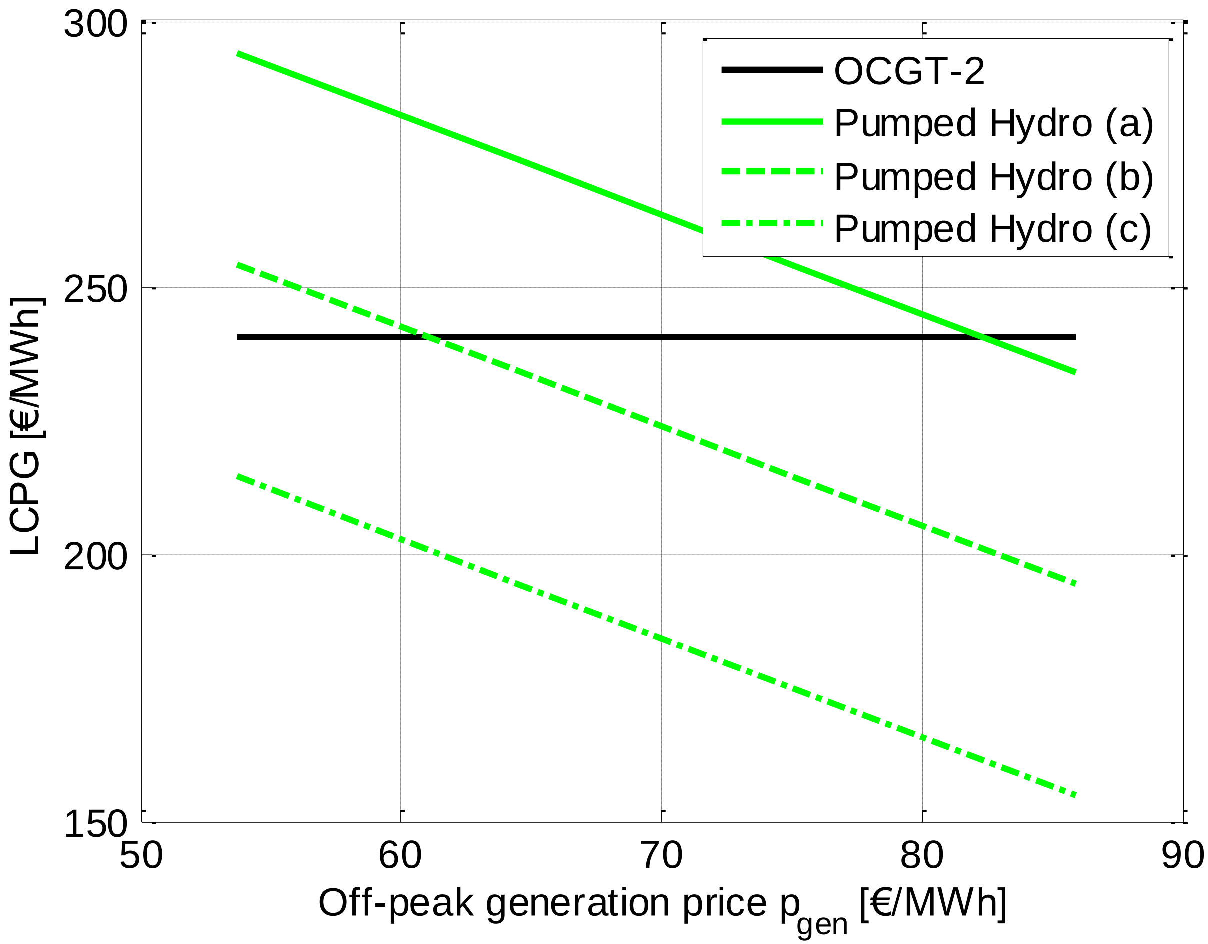
LCPG for 20 % load factor

Sensitivity on capacity price



LCPG for 7 % load factor

Sensitivity on off-peak prices and cable costs



Cable&grid costs covered by Norw. pumped hydro

100 % of total

75 % of grid costs

50 % of grid costs

Summary – Norway as a green battery

- European energy and climate policies implies a high share of unregulated wind and solar power
- Norwegian hydro can provide fast response and offers large storage capacities
- New generation and pumping assets can be built and used within todays environmental constraints
- Highly complex river and reservoir systems demands detailed operation models for balancing analyses

Summary: Pumped hydro for balancing

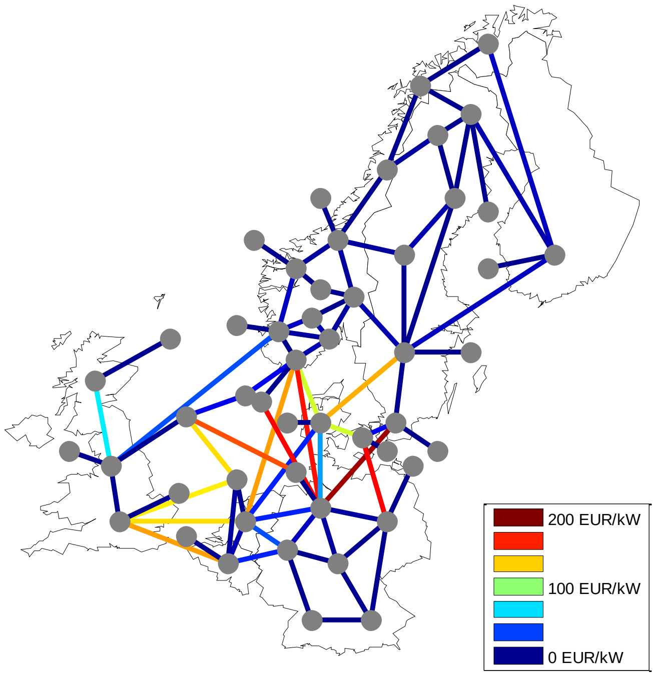
- A method for calculation of the Levelized Cost of Peak Generation (LCPG)
  - Peak periods are defined as the time of the year when non-flexible resources cannot cover all the demand
  - The method account for possible capacity payments and additional revenue during off-peak periods
- A case study of a future European power system with high penetration of wind and solar power
  - Building new reversible pumping stations between existing reservoirs in the Norwegian hydro system can be economical advantageous over new CCGT and OCGT plants
  - Additional costs of subsea cables across the North Sea and corresponding reinforcements of the mainland grid is included

Summary: Power market integration

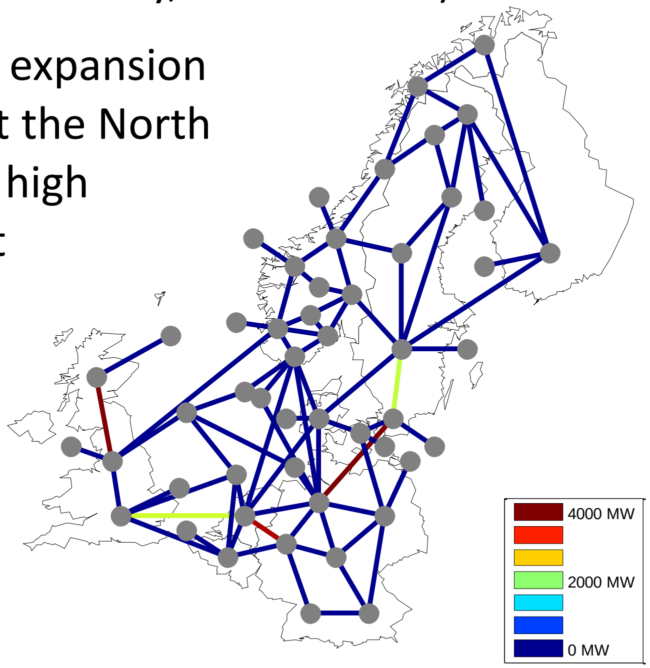
- It is the net load variations that matters
  - Load – Wind - PV
  - Geographical smoothing of RE variability
  - Geographical smoothing of RE predictability
- An efficient and integrated power market is an enabler for high RE penetration
  - Reduces the need for expensive storage
  - Reduces the need for expensive reserves
- Comprehensive studies of balancing markets in Northern Europe
  - Huge benefits of market clearing closer to operation
  - Huge benefits of integrated markets for balancing resources
  - Huge benefits of integrated markets for intra-day trading

Transmission expansion – Investment analysis

- Marginal operational profits for transmission corridors occur around the North Sea



- Increasing the capability of transmitting energy from renewable energy sources (Sweden, Scotland) to load centres (Southern Germany, Southern UK)
- No further expansion throughout the North Sea due to high investment costs



Parameter	CCGT	OCGT-1 (Aeroderivative)	OCGT-2 (F-class)
i_{ng} [€/kW]	718	705	377
n_{ng} [yr]	25	40	25
OM_{ng} [%]	3.9	3.5	3.4
η_{ng} [%]	59	35	35
α_{ng} [%]	92.8	94.7	91.9

Pumped hydro plant		Subsea cable and grid	
i_{ph} [€/kW]	400	i_{cable} [€/kW]	1153
n_{ph} [yr]	30	n_{cable} [yr]	40
OM_{ph} [%]	0.75	α_{cable} [%]	95.0
η_{ph} [%]	80	GR [%]	30
α_{ph} [%]	95.7	n_{grid} [yr]	70