Why do TSOs need hydro forecasts?

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Workshop on hydro scheduling in competitive electricity markets,
Trondheim, 18 September 2015

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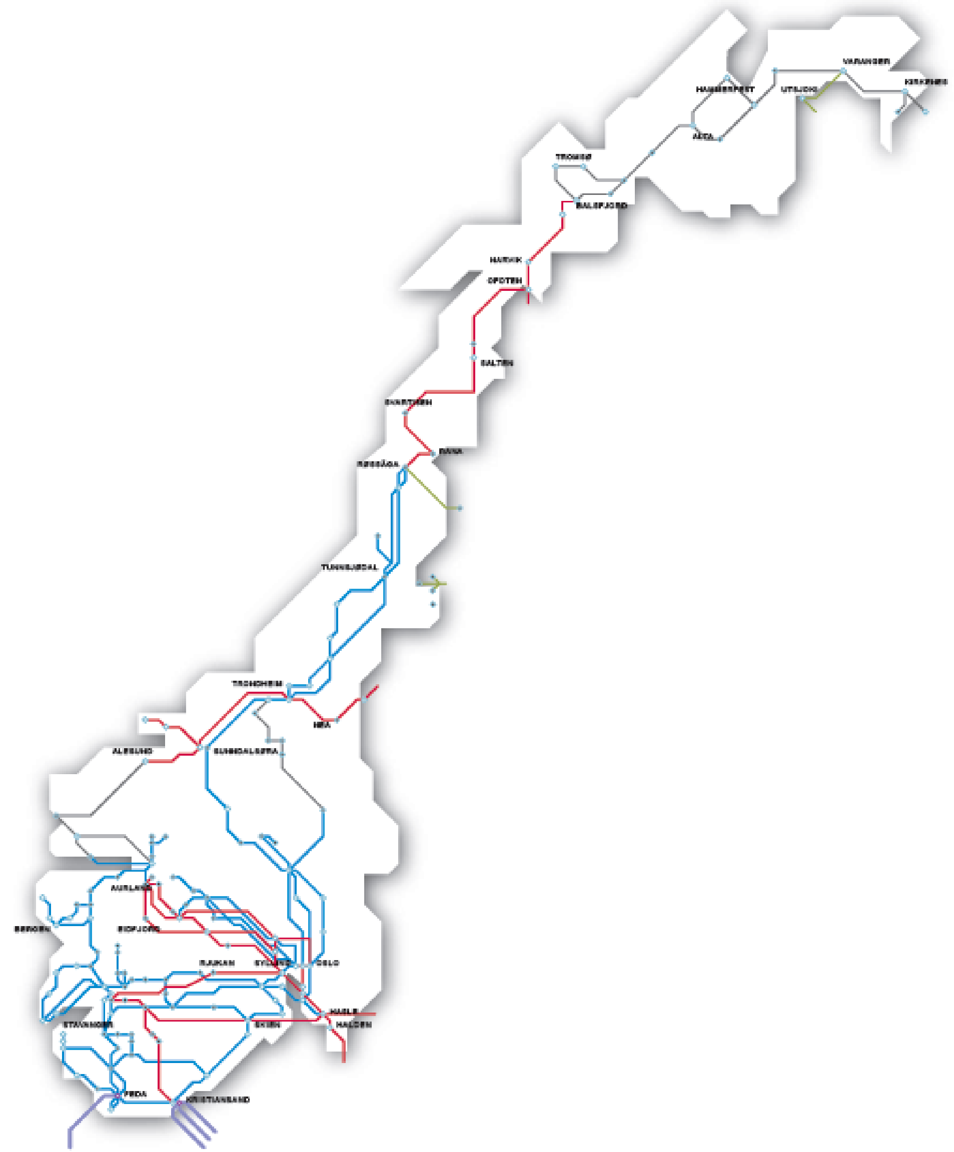
Overview

- This is Statnett
- ENTSO-E Network codes
- Market planning process & TSO role
- D-2 capacity allocation
- Flow based market coupling
- Marginal loss coefficients week ahead
- The role of hydro forecasts

This is Statnett

- Statnett is the Transmission System Operator in the Norwegian energy system
- Statnett operates and owns about 11 000 km of lines and cables and approximately 150 transformer stations throughout Norway
- Operations are monitored 27/7/365 from one national control centre and three regional control centres
- Statnett is also responsible for interconnectors to Sweden, Denmark and the Netherlands



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Our main objectives

- To ensure a stable and secure supply of electricity by coordinating production and consumption
- To ensure long-term quality by developing the Norwegian main grid
- To offer equal access to the main grid to all market players
- To ensuer accessible transmission routes by means of good maintenance practices

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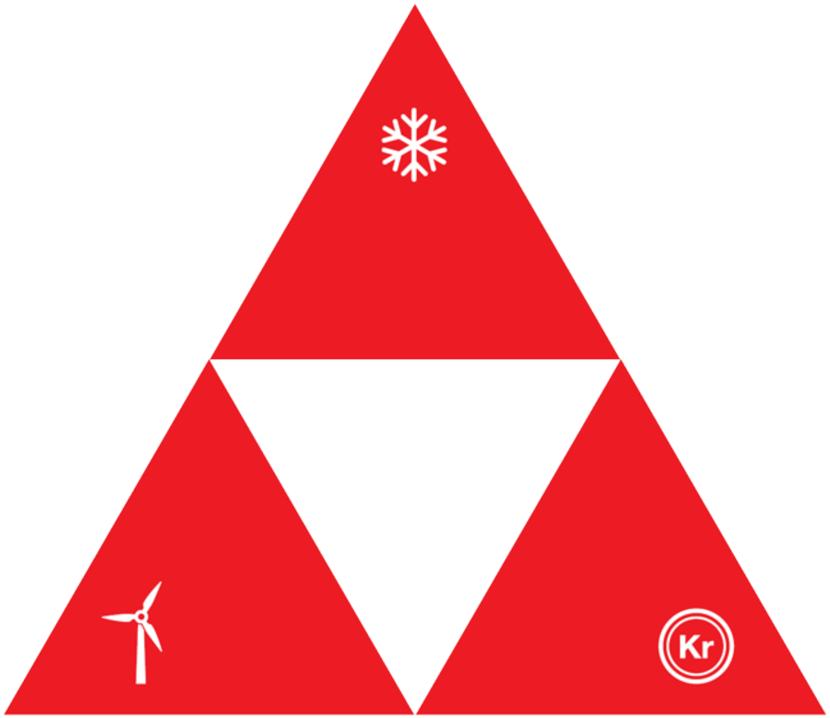
Our strategy

Security of supply
Maintain security of supply through operation, develepment, monitoring and preparedness

Climate
To facilitate the realisation of Norway's climate objectives

Value creation
To facilitate value creation for our customers and Norwegian society at large



ENTSO-E Network Codes / Guidelines

common rules for electricity markets, as defined in Regulation (EC) No. 714/2009

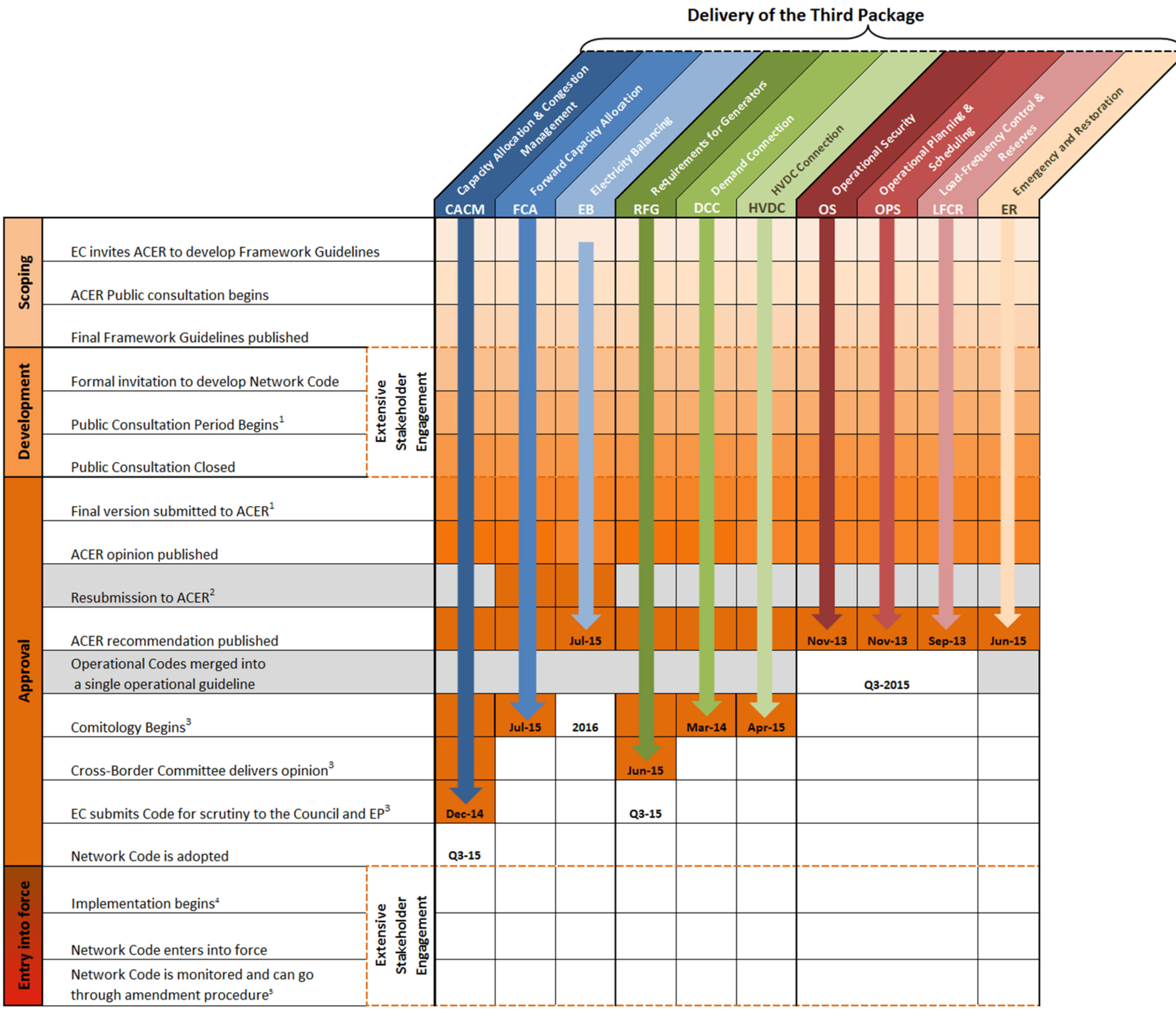
- Grid Connection Related codes
  - **Requirements for Generators (RfG)**
  - Demand Connection (DCC)
  - **HVDC Connection (HVDC)**
  - Connection Procedures (CP)

- Guideline on Transmission System Operation
  - Operational Security (OS)
  - Operational Planning and Scheduling(OPS)
  - Load Frequency Control and Reserves (LFCR)
  - Operational Procedures in an Emergency (EP)

Finally approved

- Market Related codes
  - Forward Capacity Allocation (FCA)
  - Electricity Balancing (EB)

- Guideline
  - **Capacity Allocation and Congestion Management (CACM)**


Delivery of the Third Package
Capacity Allocation & Congestion Management
Forward Capacity Allocation
Electricity Balancing
Requirements for Generators
Demand Connection
HVDC Connection
Operational Security
Operational Planning & Scheduling
Load-Frequency Control & Reserves
Emergency and Restoration
CACM
FCA
EB
RFG
DCC
HVDC
OS
OPS
LFCR
ER
Scoping
EC invites ACER to develop Framework Guidelines
ACER Public consultation begins
Final Framework Guidelines published
Development
Formal invitation to develop Network Code
Public Consultation Period Begins1
Public Consultation Closed
Extensive Stakeholder Engagement
Approval
Final version submitted to ACER1
ACER opinion published
Resubmission to ACER2
ACER recommendation published
Operational Codes merged into a single operational guideline
Comitology Begins3
Cross-Border Committee delivers opinion3
EC submits Code for scrutiny to the Council and EP3
Network Code is adopted
Entry into force
Implementation begins4
Network Code enters into force
Network Code is monitored and can go through amendment procedure5
Extensive Stakeholder Engagement
Jul-15
Nov-13
Nov-13
Sep-13
Jun-15
Q3-2015
Jul-15
2016
Mar-14
Apr-15
Jun-15
Dec-14
Q3-15
Q3-15

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EU Guideline on Capacity Allocation and Congestion Management (CACM)

- Art 18.3
  - For each scenario, all TSOs shall jointly draw up common rules for determining the net position in each bidding zone and the flow for each direct current line. These common rules shall be based on the best forecast of the net position for each bidding zone and on the best forecast of the flows on each direct current line for each scenario and shall include the overall balance between load and generation for the transmission system in the Union
- Art 19.2:
  - Each individual grid model shall represent the best possible forecast of transmission system conditions for each scenario specified by the TSO(s) at the time when the individual grid model is created.
- Art 19.5
  - Each TSO shall provide all necessary data in the individual grid model to allow active and reactive power flow and voltage analyses in steady state.
- Art 24.2
  - The generation shift keys shall represent the best forecast of the relation of a change in the net position of a bidding zone to a specific change of generation or load in the common grid model

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EU Guideline on System Operation (SO)

- Article 35.3(d):
  - To coordinate their operational security analysis and to establish the common grid model [ ], each TSO shall exchange with at least all other TSOs from the same synchronous area [ ]:
    - d) the forecasted aggregate amount of injection and withdrawal, per primary energy source, at each node of the transmission system for different timeframes . This forecast shall be realistic and accurate.

- Article 37.5:
  - Each DSO shall provide to the TSO it is connected to, per primary energy sources, the total aggregated generating capacity of the type A power generating modules [ ]

0,8 kW ≤ P ≤ 1,5 MW

- Article 105.1(c)
  - Each TSO shall perform a control area adequacy analysis on a D-1 and intraday timeframe on the basis of:
    - c) forecasted generation from renewable energy sources;

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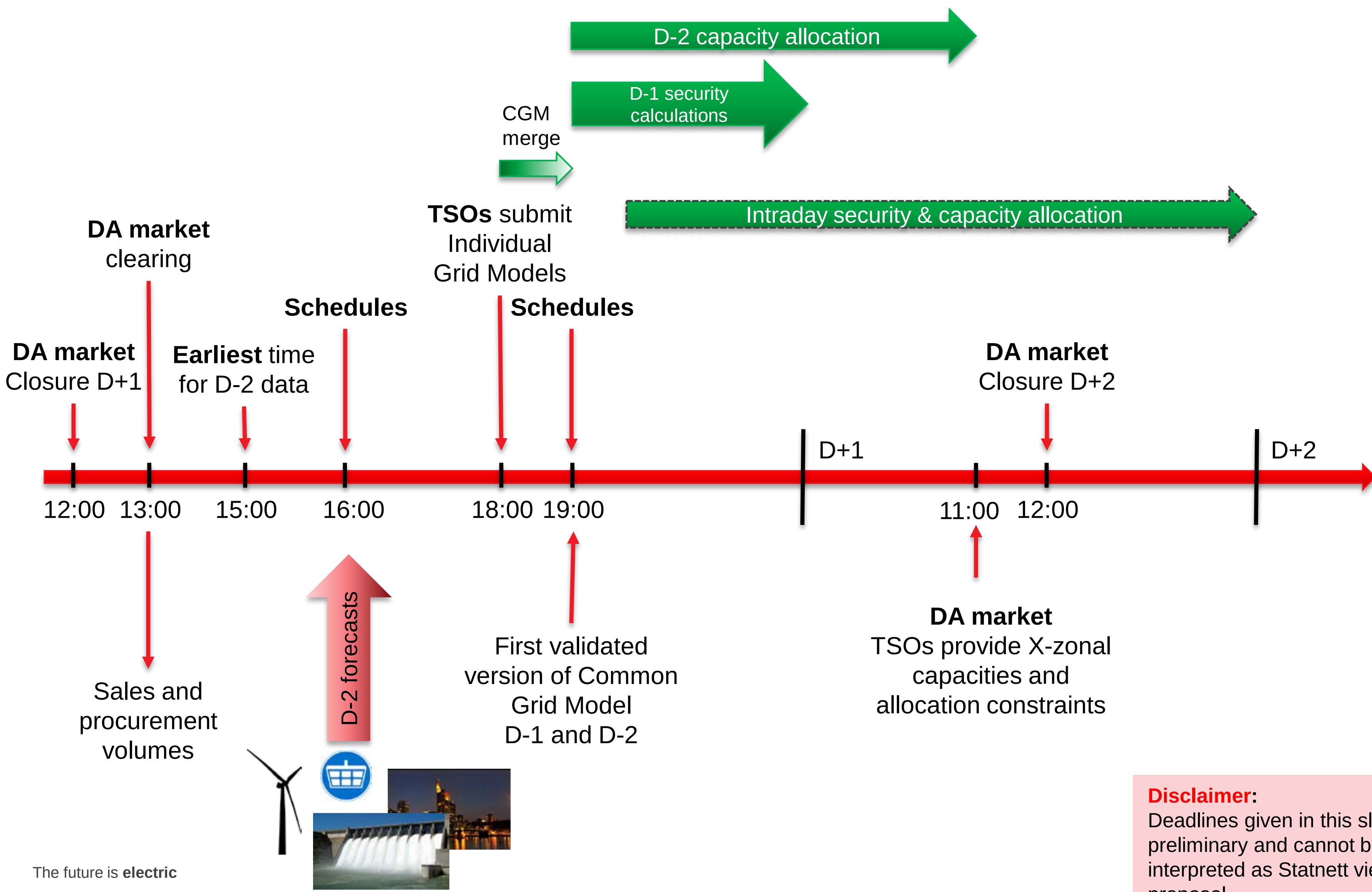
Coming TSO market planning processes



Disclaimer: Deadlines given in this slide are preliminary and cannot be interpreted as Statnett view or proposal

D-2 process (for capacity calculation)

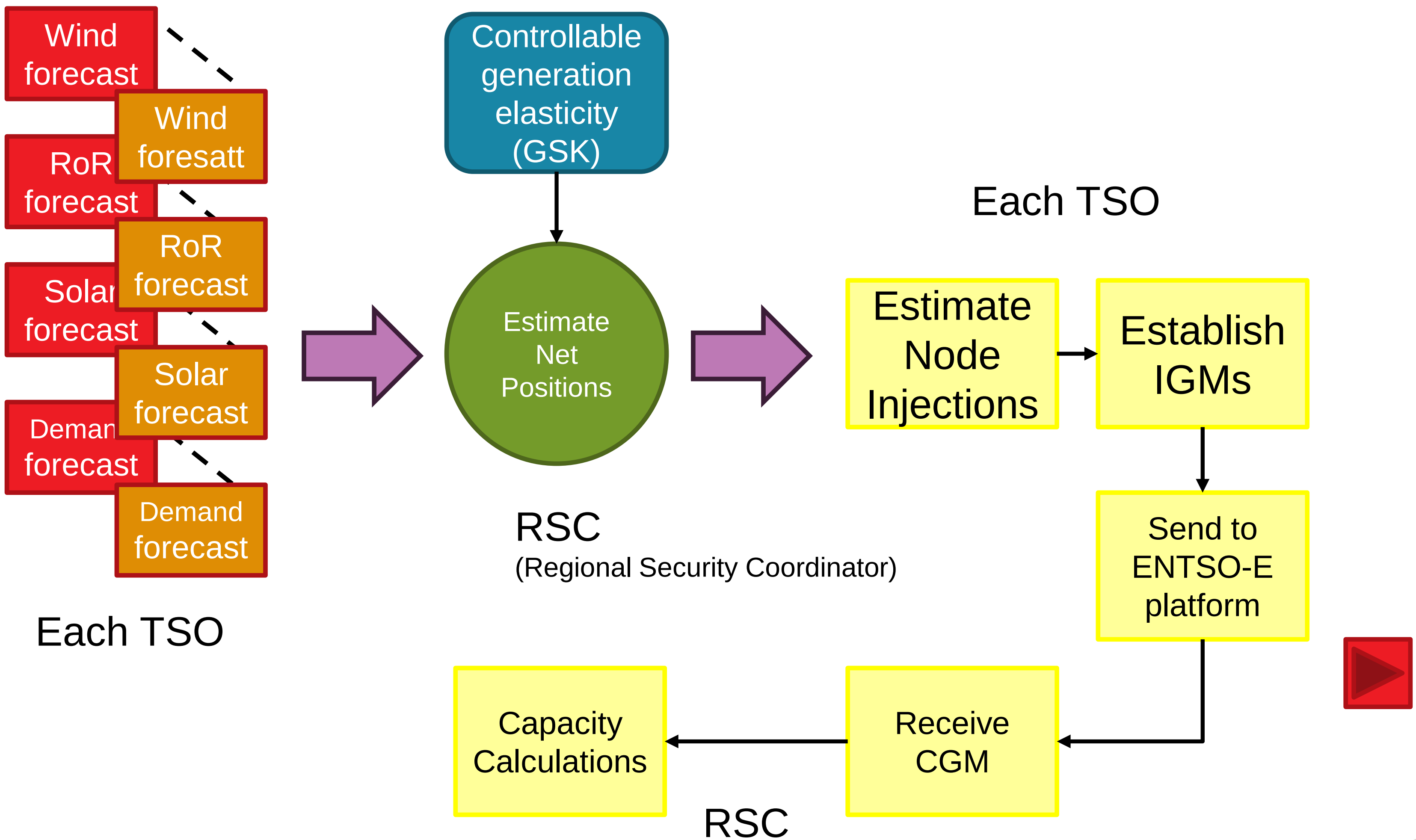


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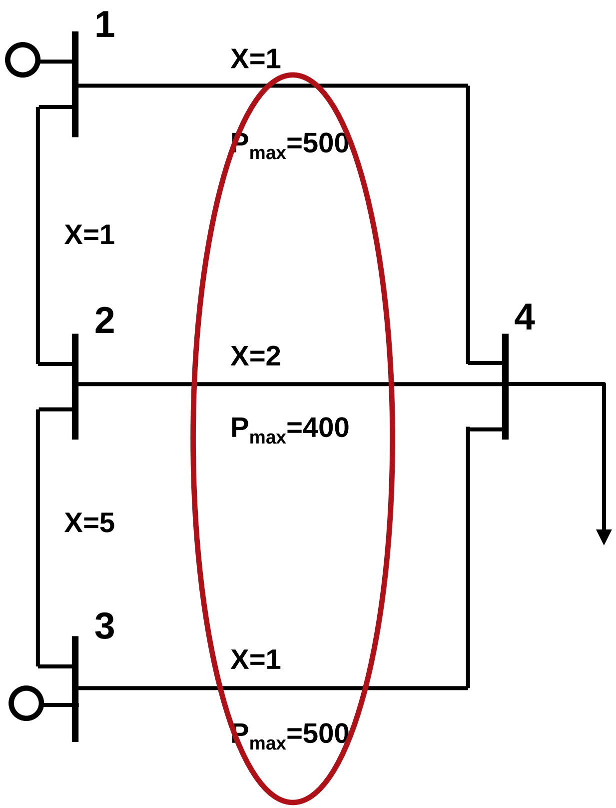
Illustration – why are good forecasts important?



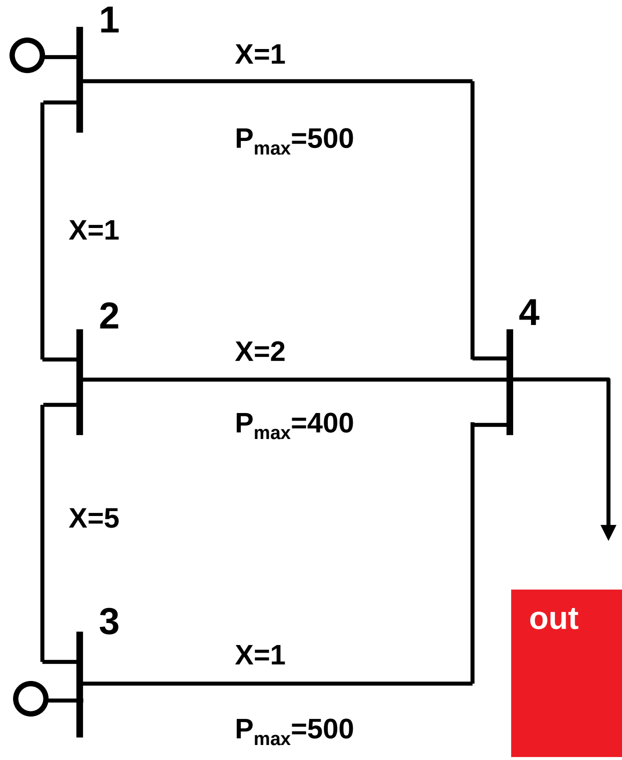
PTDF matrix

	1	2	3	4
1-2	0,29	-0,43	-0,07	0
1-4	0,71	0,43	0,07	0
2-3	0,07	0,14	-0,14	0
2-4	0,21	0,43	0,07	0
3-4	0,07	0,14	0,86	0

"Straight forward" transfer capacity: 900 MW (N-1)
However (disregarding outages)

- P1=900 / P2=0 not possible, overload 1-4
    - most "skewed" distribution is 678 / 222
    - line 1-4 at limit for 700 / 0
- P1=0 / P2=900 not possible, overload 3-4
    - most "skewed" distribution is 346 / 554
    - line 3-4 at limit for 0 / 583
- Without any knowledge:
    - corridor capacity = 583 MW
- If certain that P1 < 678 MW and P2 < 554 MW:
    - Corridor capacity = 900 MW

Same example, include outages



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out	P1 max	P2 max	900 / P1 max	900 / P2 max	Cap / no know-ledge	Cap / Perfect Fore-sight
1-4	534-0	0-571	460-440	460-440	534	900

Flow based market coupling

- Today (Nordic system): capacities between markets based on Net Transfer Capacities
  - Does not consider load flow equations
  - Challenging, cf. previous slide

- Flow Based approach: uses PTDF matrices
  - Linear approximation of (non-linear) flow equations
  - Better representation of physical reality
    - In general more capacity to the market

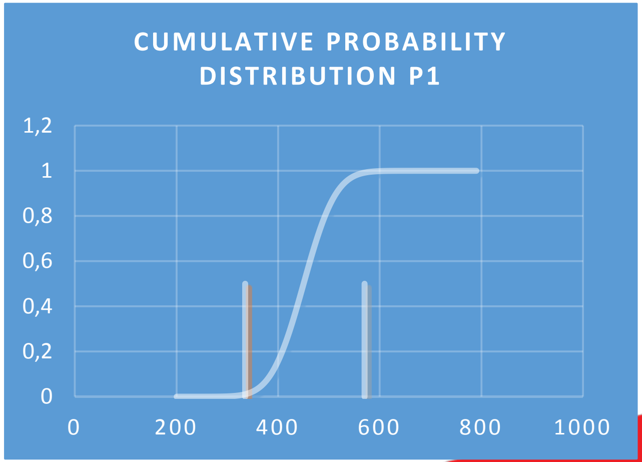
- Quality of linear approximation highly dependent on "base case"
  - We need good forecasts!

Importance of forecasts

- Without <u>any</u> pre-knowledge, TSO must set capacity considering most inadvertent case

- With <u>perfect</u> knowledge, TSO can use known production pattern to determine capacity
  - May be <u>significantly</u> higher as example illustrates

- With <u>realistic</u> knowledge, capacity will be somewhere in between



Marginal loss coefficients

- Norwegian regulation regarding the energy term in the grid tariff:
  - Must reflect the cost of the marginal losses that a grid customer incurs by injecting or withdrawing power
  - Must reflect the system load in the total system

➢ The energy term must give price signals to grid users to incentivize efficient grid utiliziation

Energy term *(NOK) =*

Marginal loss coeffient (%) • ***System price*** *(NOK/MWh)* • ***Exchange*** *(MWh)*

Principles for calculations

- **Weekly** update
- Coefficients are calculated **week-ahead** to allow market participants to adapt
- Separate coefficients:
  - for each **node** in the transmission grid
  - For **day** and **night / weekend**
- Coefficients are symmetrical around zero: $MLC_{in} = -MLC_{out}$
- Maximum values are ± **15%**
- Calculated on the basis of a **Nordic** load flow forecasts

Load flow forecast

Fixed input

- Grid model
- Plant data

Variable input

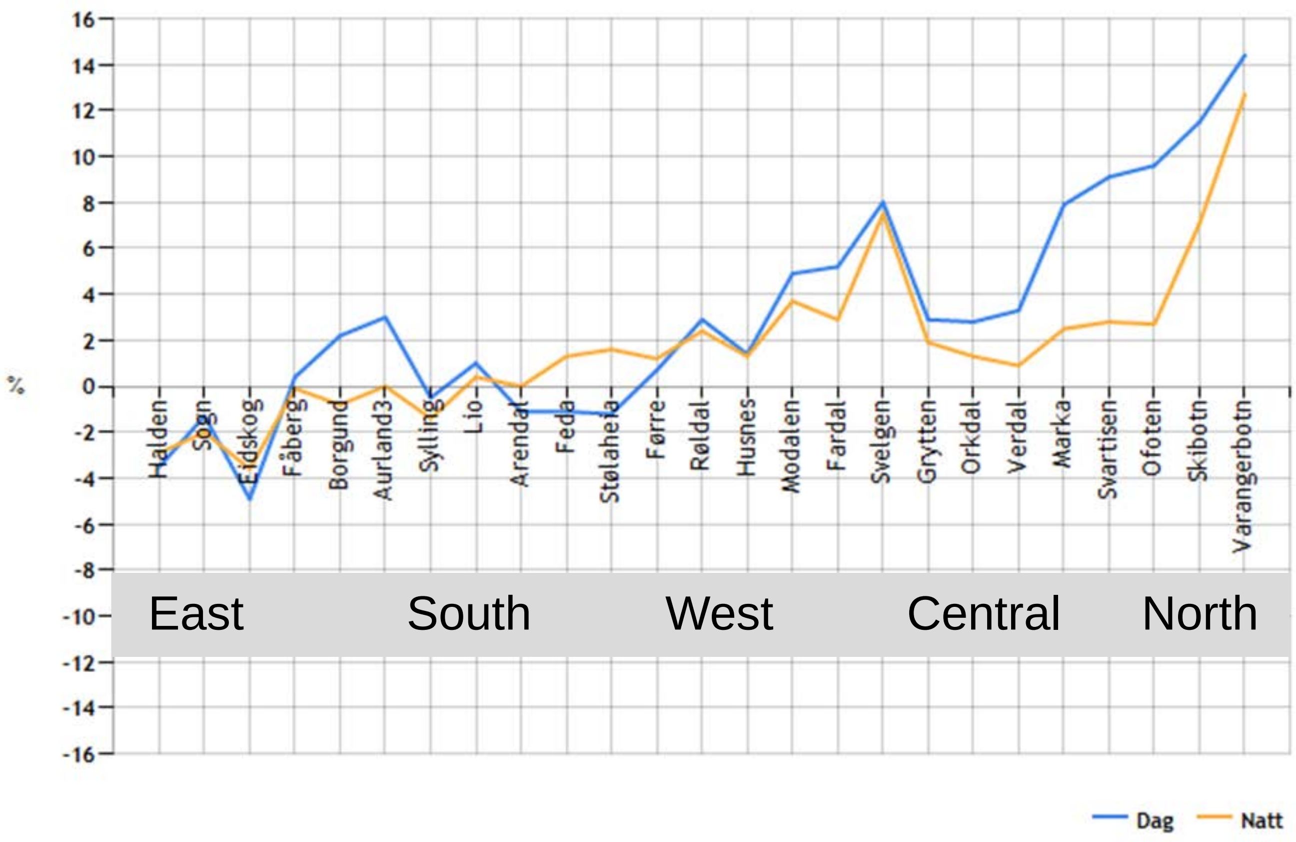
- Reservoir levels
- Demand forecasts
- Inflow and snowpack forecasts
- Outages
- Fuel prices
- …

Quality of the forecasts depends on

- Update frequency
- Local conditions
- Model
- Experience/approach

Example of loss coefficients

Marginal loss coefficients in the transmission grid, week 17



Positive value

- *Pay for production*
- *Get paid for demand*

Negative value

- *Get paid for production*
- *Pay for demand*

TSO perspective on hydro forecasts

- With ~70 % storage capacity, Norwegian hydro is extremely flexible
  - In the short term, production normally depends on prices more than inflow
- TSO perspective: for estimation of generation, inflow forecasting only makes sense for non-storable inflow
  - For storable hydro other, "market related" approaches are necessary
- But what is "non-storable"?
  - Always: plants without reservoirs (directly or upstream)
  - Sometimes: (almost) any other plant
- And what is "sometimes"?
  - Whenever the combination of reservoir status + inflow makes generation price inelastic

Challenges

- Short term
  - Forecasting production of independent run-of-river plants
    - where we have production data
- Long term (possibly)
  - Forecasting production of all run-of-river plants, including those that are part of a portfolio
- Limited data availability

Conclusions

- EU Guidelines and Network Codes require TSOs to use best possible data for capacity allocation
- Requires forecasts two days ahead of, among others, hydro generation
- Mix of "physical" and "market" forecasting
- Norwegian regulation also requires week ahead forecasting
- TSOs have less data access (and need) than producers