Innovative electricity markets to incorporate intermittent production

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Company presentation

- Ea Energy Analyses
  - Research and consulting. Energy analyses: Technology and markets
  - 10 full-time employees
- Customers
  - Operation agent for RETD
    - International Energy Agency Implementing Agreement on Renewable Energy Technology Deployment
  - Nordic Council of Ministers
    - Steps for improved congestion management and cost allocation for power exchange and transit
  - Research project
    - Demand response from houses with electric heating
    - Demand as frequency controlled reserve

IEA Implementing Agreement on Renewable Energy Technology Deployment (RETD)

- 9 member countries:
  - Canada, Denmark, France, Germany, Ireland, Italy, the Netherlands, Norway & the United Kingdom
  - Japan as observer
- RETD vision
  - Significantly higher utilisation of RE technologies as a result of international cooperation encouraging the accelerated and efficient deployment of RE.

Role of the RETD

- Help and advise members on the most cost effective way of deploying RE technologies
- Focus on cross-cutting barriers
  - Across technologies and nations
- Learning and adapting the market for RE deployment
- In association with other IAs disseminate information and enhance knowledge of RE deployment in public and private sector decision making.

From marginal to large scale

- When intermittent production is only marginal
  - *Connect and forget*
- When intermittent production is large-scale
  - More advanced methods are needed
  - Fair and efficient markets

Incorporation of intermittent power

- Technological options
  - Hydro plants and pumped storage can absorb intermittent power
  - Demand response can act as an energy storage
- Market options for incorporation intermittent power and activating “energy storage technologies”
  - Day-ahead markets
  - Hour-ahead markets
  - Cross border power exchange
  - Markets for unplanned production

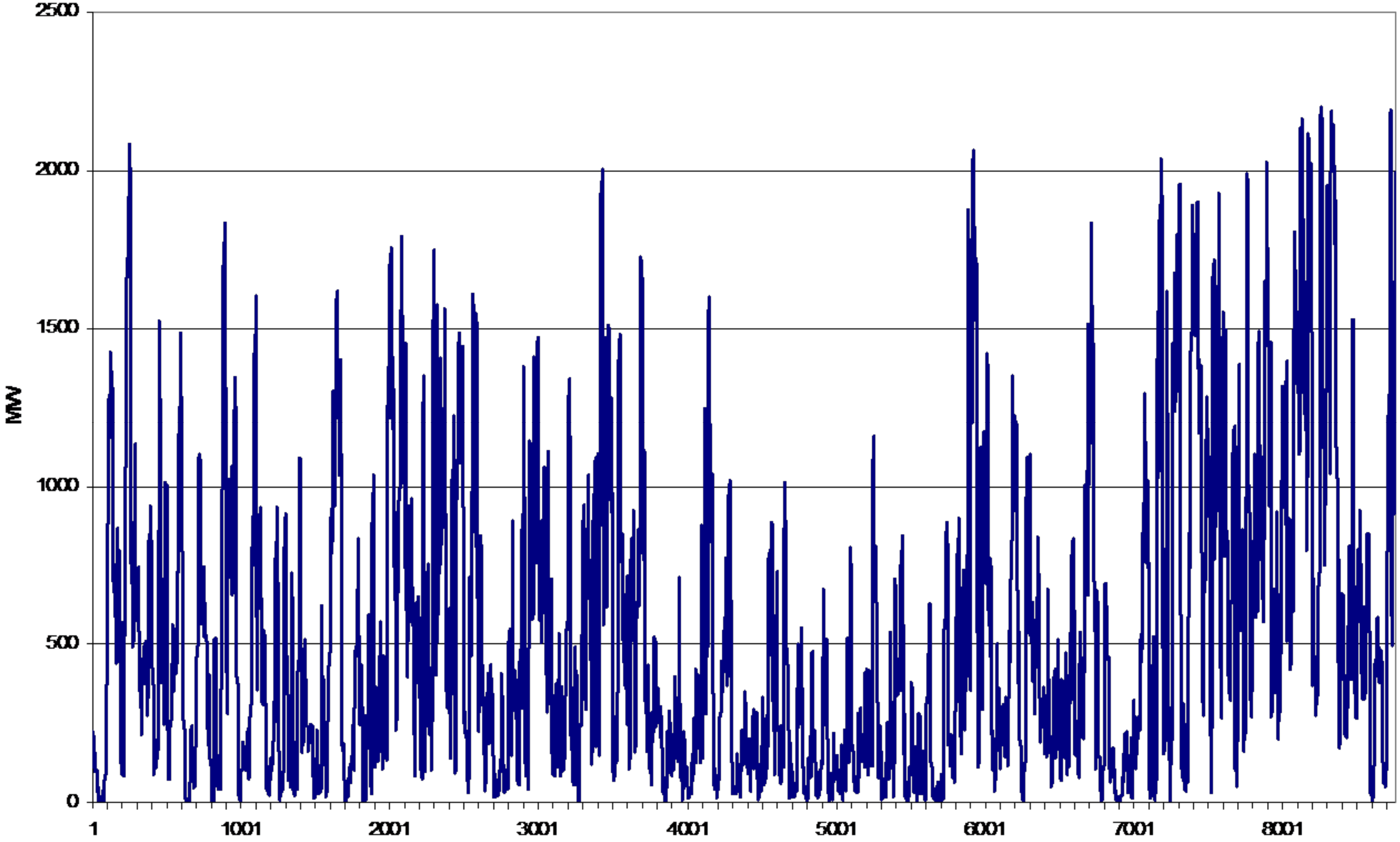
Example:

WIND POWER

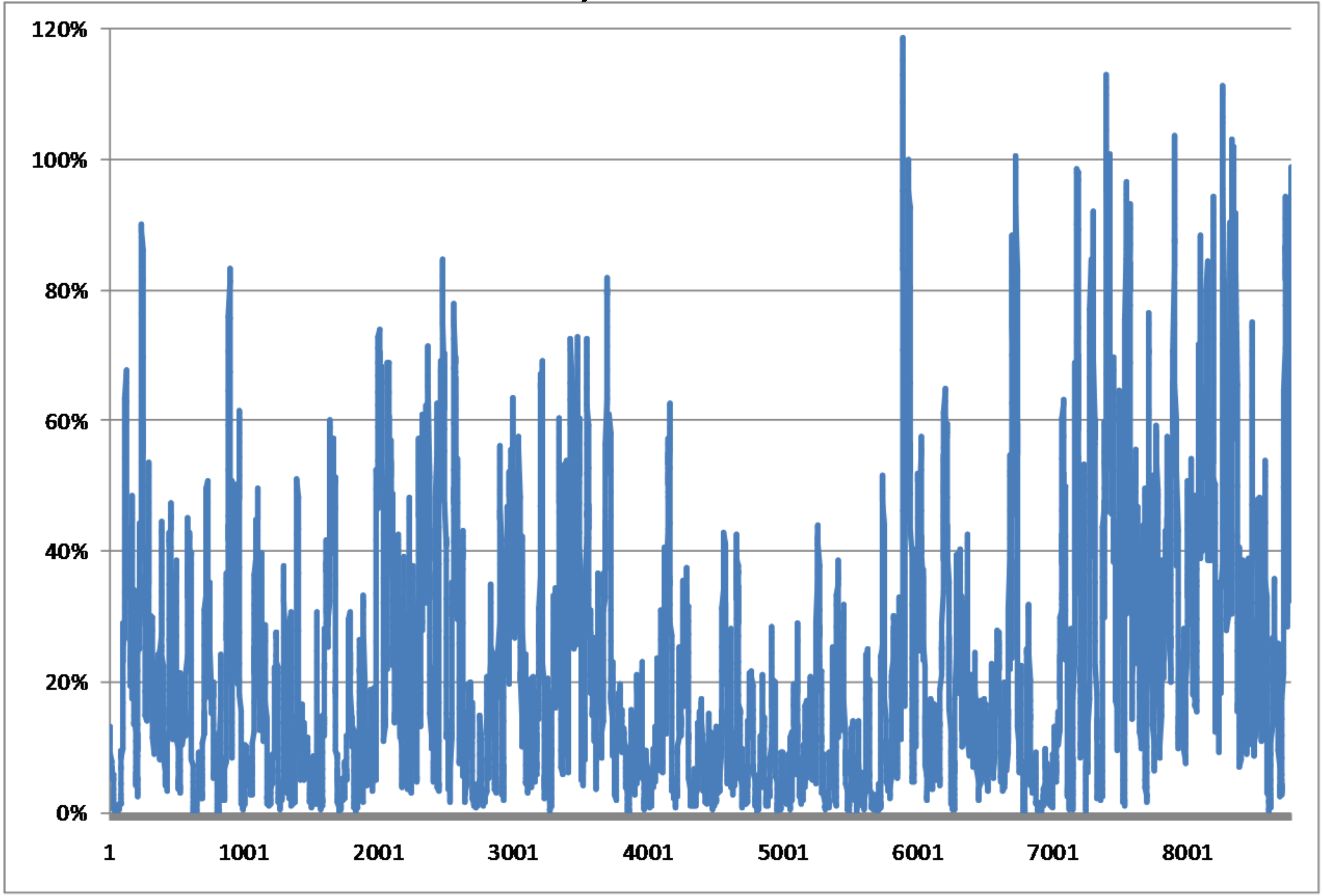
Wind power as an example

- Challenges with wind power
  - Problem 1: Intermittent
  - Problem 2: Difficult to predict

Hourly wind power generation in Denmark West, 2006

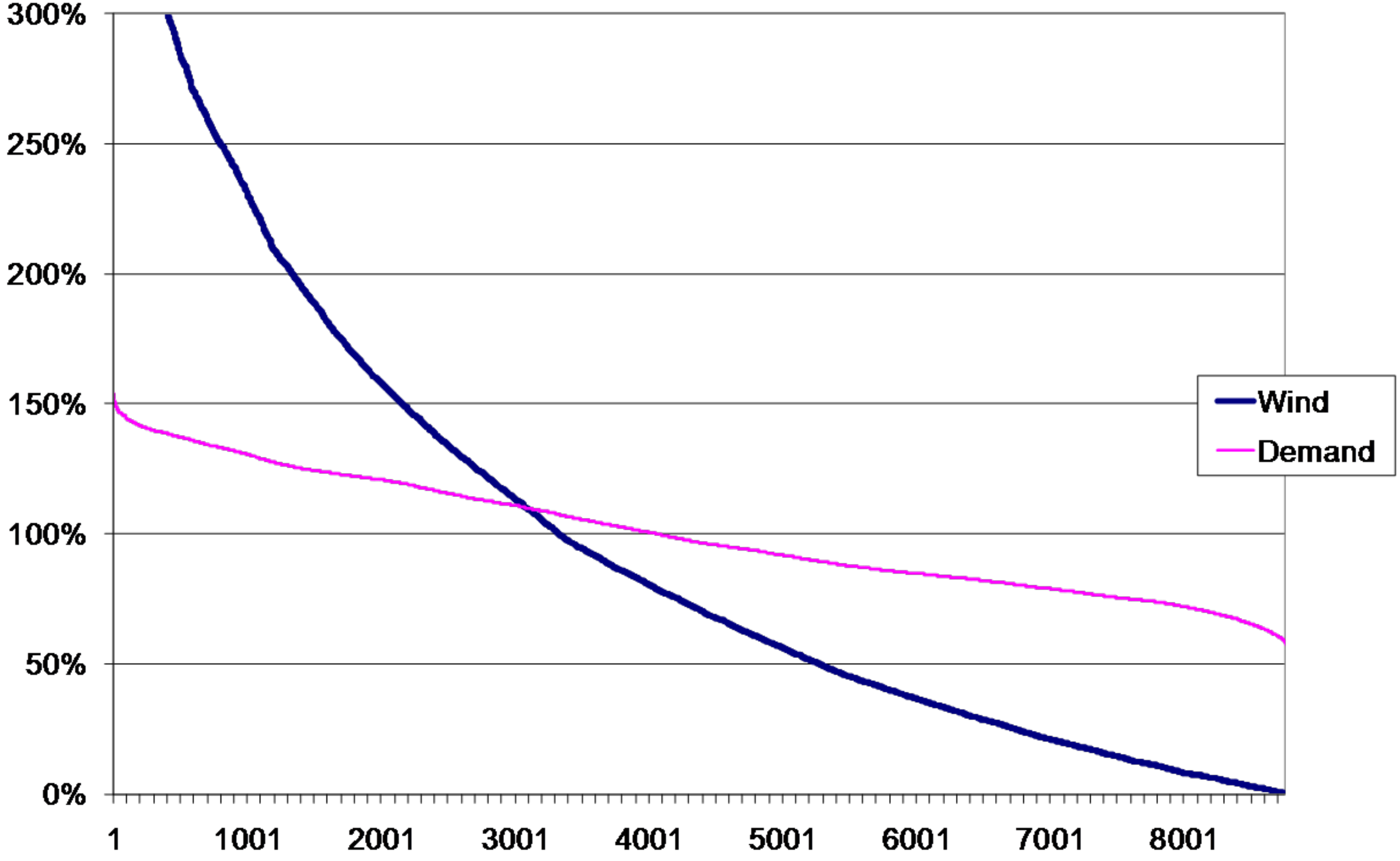


Wind power in percentage of demand, Denmark West, 2006



Wind and demand as duration curves

100% = Average hourly value



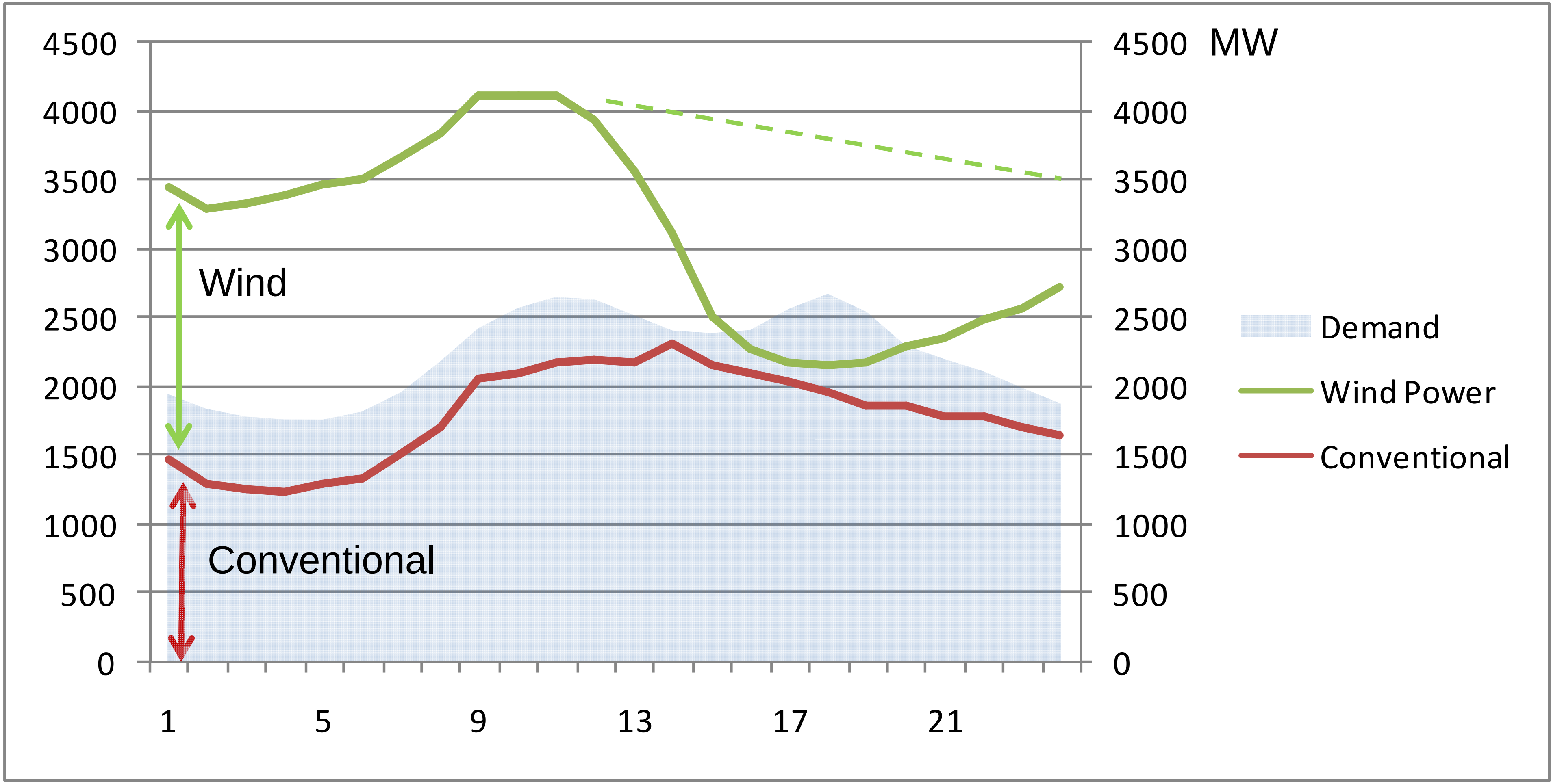
Wind power in Denmark

- Wind power generation in 2006 = 17% of demand (22% in Denmark West)
    - 3,100 MW (423 MW offshore)
- New goal for 2025: 50% electricity from wind power
    - 6,200 MW (2,600 MW offshore)

Predicting storms

- The hardest challenge with wind power is when a storm forces (all) generators to stop
  - From full production to zero in less than a few hours

Storm on 8 January 2005



INNOVATIVE MARKETS

Four examples

- Near real-time markets
  - Hour-ahead market: Nord Pool Elbas
- Dealing with unplanned production
  - Nordel vs. UCTE
- Developing the market for regulating power
  - Demand as regulating power
- Ideal congestion management
  - Nodal pricing

Market design is man-made

- Different market designs can favour different technologies
  - Day-ahead market with hourly values is fine for hydro power
  - Possibility of using block bids is essential for large coal-fired plants
  - Wind power suffers with day-ahead markets

Predicting wind power

- Difficult to predict hourly wind power production in day-ahead market (12-36 hours ahead)
  - 60% of actual production is predicted
- In an hour-ahead market more than 95% can be predicted
  - Comparable to conventional generation

Hour-ahead market: Elbas

- Trade until one hour before delivery hour
  - Stock exchange type of trade
- Sweden, Finland, Eastern Denmark, Germany
  - Western Denmark from 11 April 2007
- Volume in 2006: 1 TWh (~ 100 MW)
  - Compared to day-ahead: 250 TWh

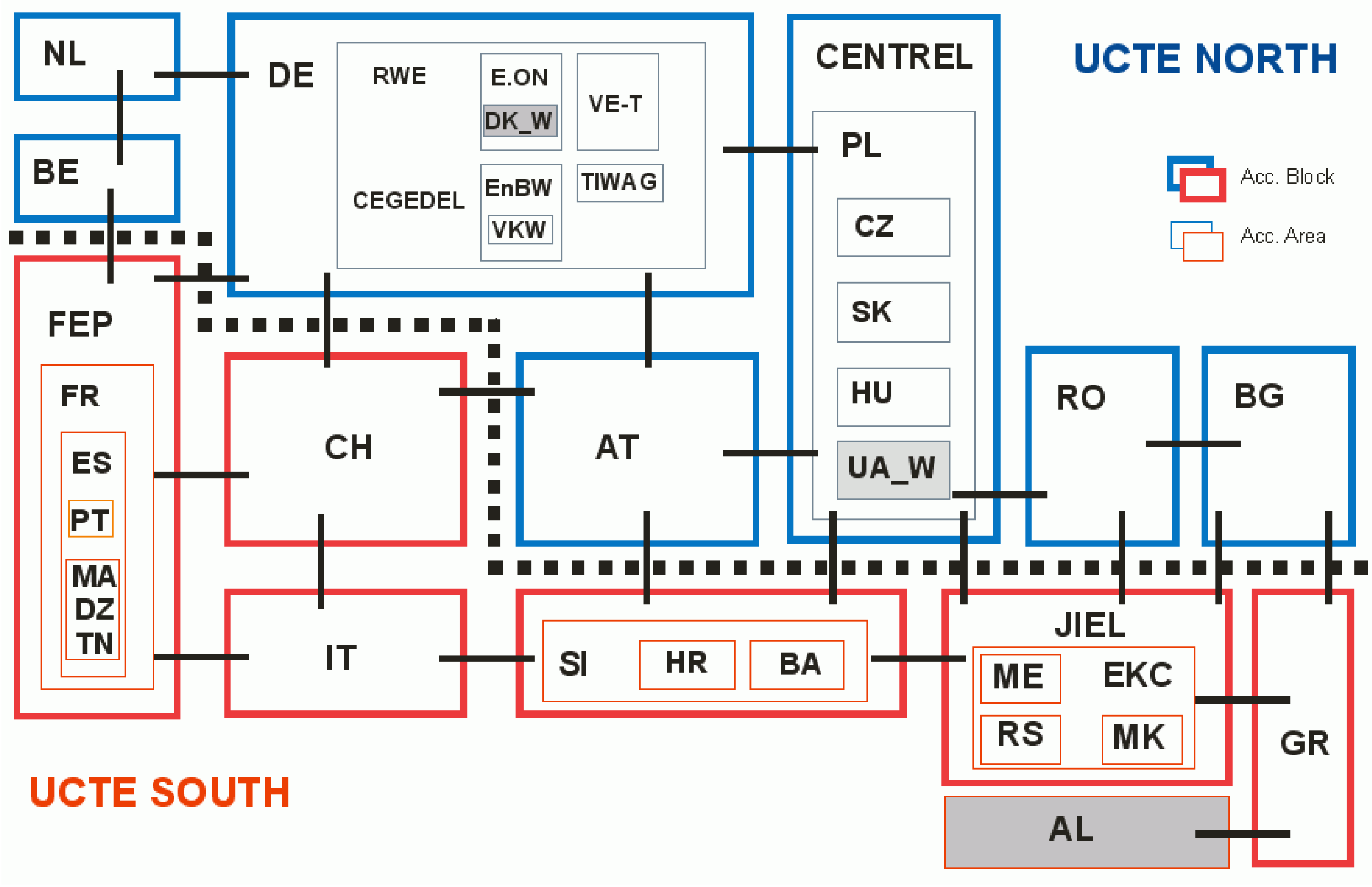
Imbalances

- Imbalances = Difference between planned and actual power generation (or demand)
- Regulating power is used to counteract imbalances
  - Activated with 15 minutes notice

Dealing with imbalances

- In Nordel
  - Imbalances are allowed to flow to neighbouring countries
  - Only total imbalance is dealt with (smoothing effect)
  - Regulating power is activated where cheapest
- In UCTE (total volume = 5 times Nordel)
  - Unplanned production must be balanced in each control block (= one or several control areas)
  - Imbalances have to be collected and offset during the following week.

UCTE


NL
DE
RWE
E.ON
DK_W
VE-T
CEGEDEL
EnBW
VKW
TIWAG
CENTREL
PL
CZ
SK
HU
UA_W
UCTE NORTH
Acc. Block
Acc. Area
BE
FEP
FR
ES
PT
MA
DZ
TN
CH
AT
RO
BG
IT
SI
HR
BA
JIEL
ME
EKC
RS
MK
GR
AL
UCTE SOUTH

Improving the market for regulating power

- Allowing demand to act as regulating power
  - Revise rules for measurements (no need for real-time)
  - Minimum effect (<10 MW)
  - Maximum duration (1 hour must be accepted)
  - Return energy (must be allowed, within some margins)
  - Reservation period (must be per hour)
  - Price signal instead of technical control

Nodal pricing

- Intermittent power creates congestions in transmission grid
- Important to use grid optimally
- Nodal pricing is the ideal
    - Optimal use of grid
    - Correct price in each node = Marginal cost of supplying electricity to each node

INVITATION TO DEVELOP PROJECT

Project to be developed:

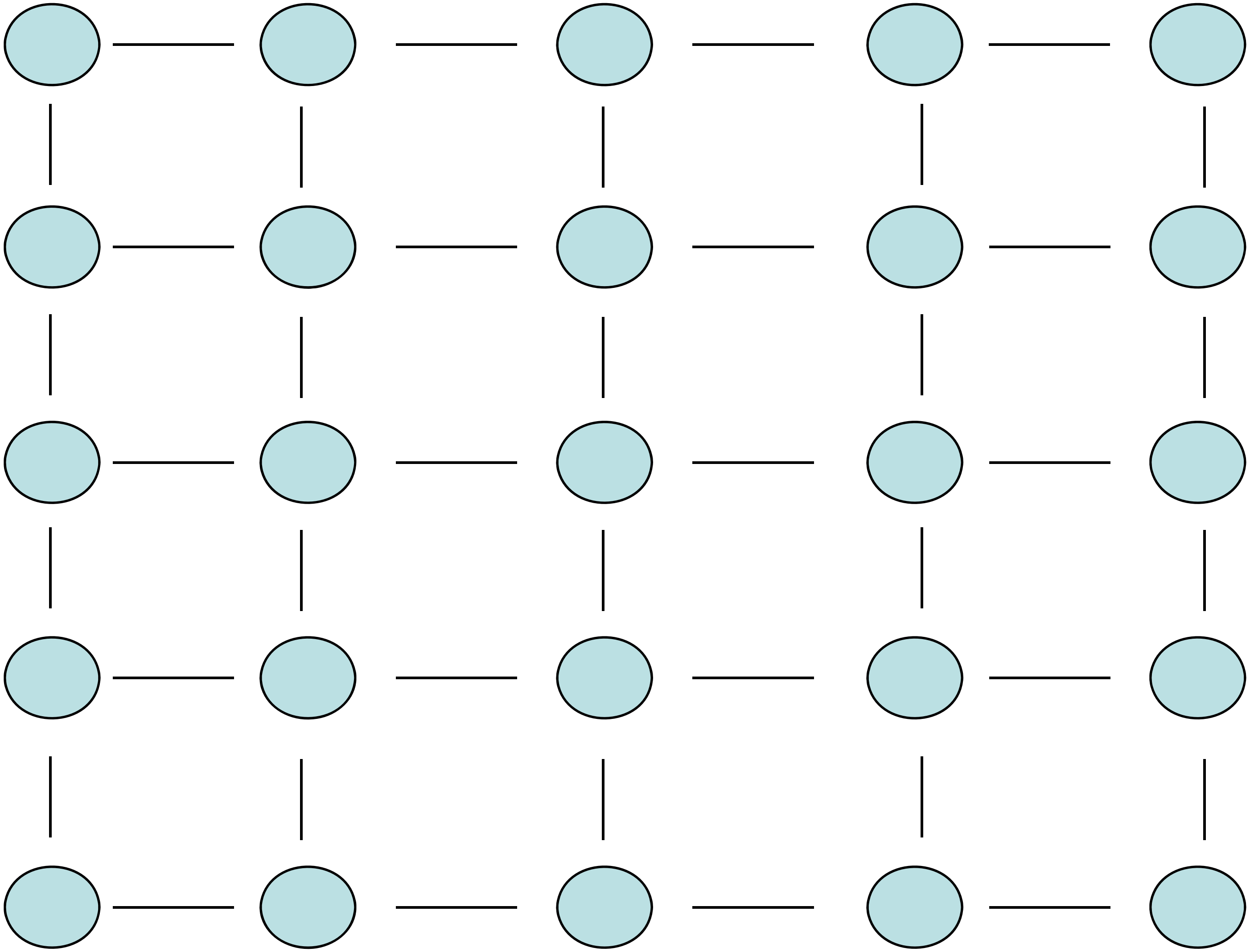
Innovative electricity markets to incorporate intermittent production

- To identify electricity market products and services needed for a better integration
- To give examples on how market systems could effectively and fairly incorporate intermittent sources of RE
- To develop means for a proactive grid planning
- To show how to prepare markets for dealing with cross-border electricity trade caused by intermittent supply

Illustration of the benefit of nodal pricing

Lars Bregnbæk and Mikael Togeby
Ea Energy Analyses

Network model



Model

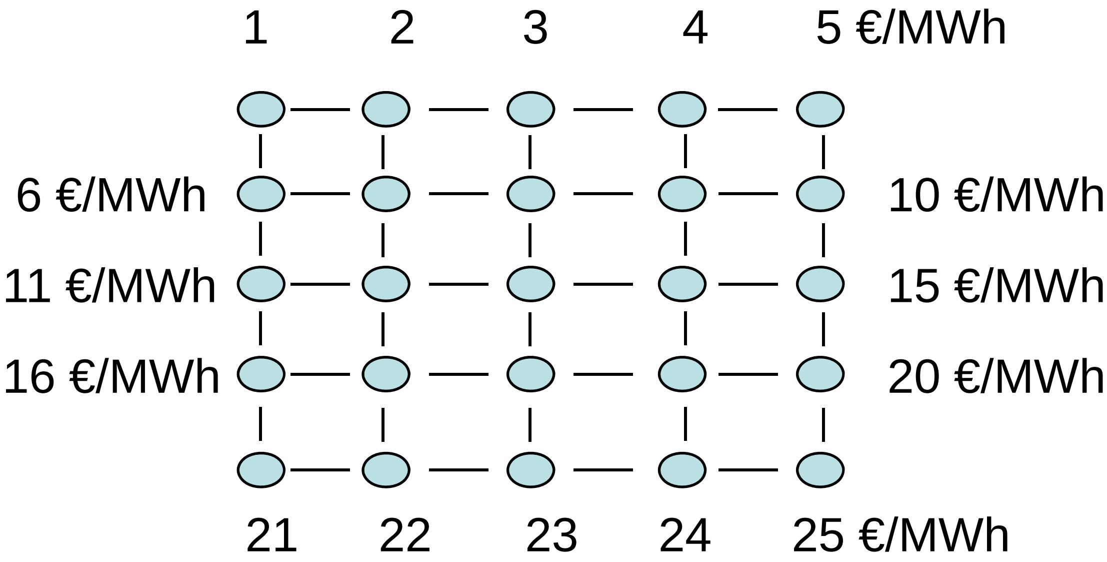
- Power flow determined by laws of physics (Kirschhoff Voltage law)
  - With given demand and generation: Power flows can be calculated
- Energy losses are not considered
  - Except directing power flow
- Solution found with a simple optimising model implemented in GAMS

Load

- Demand in each node = 1 MW
- Total demand = 25 MW
- Inelastic demand

Generation

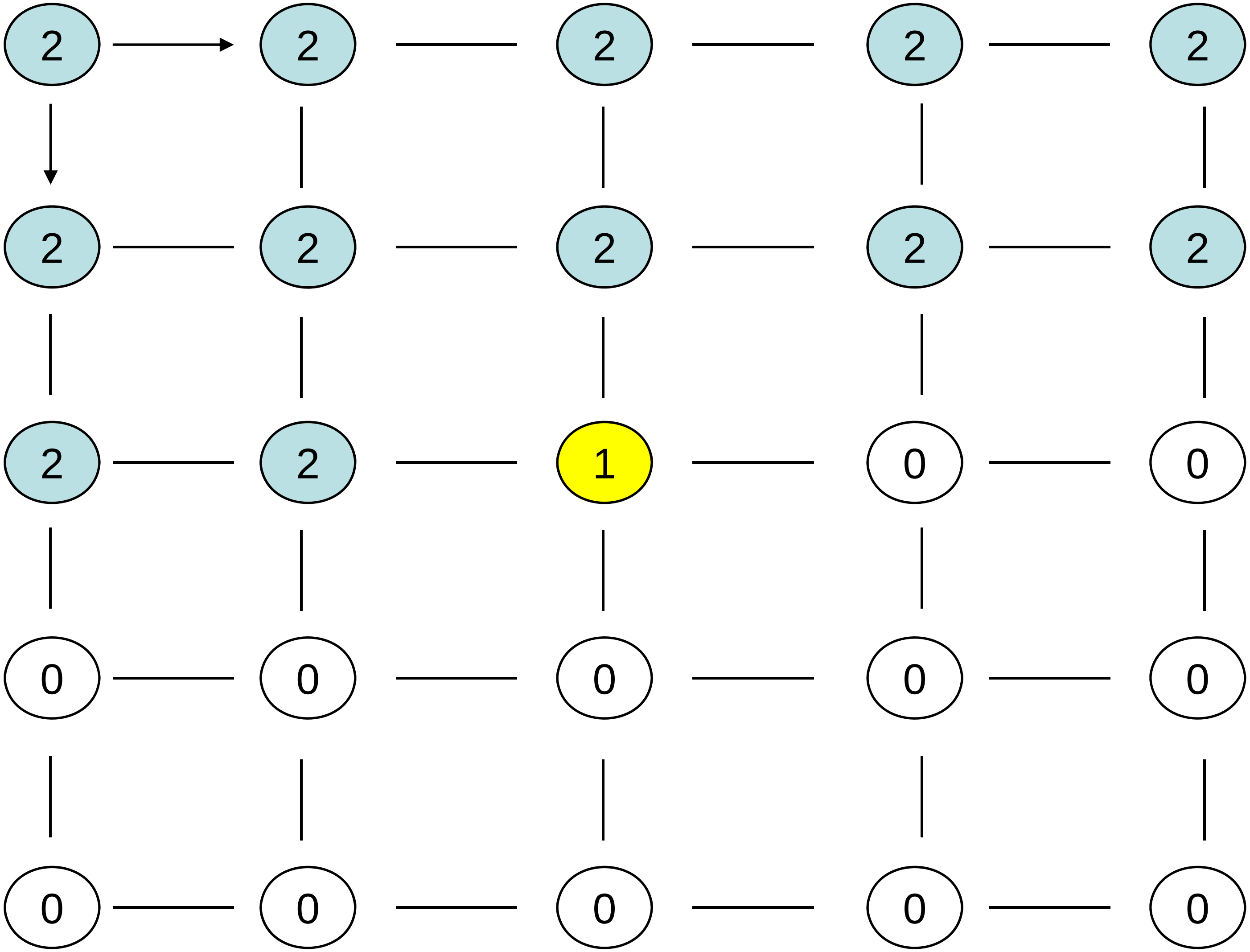
- Each node can generate between 0 and 2 MW
- Marginal cost of each generator varies from 1 to 25 €/MWh = node number



Three cases

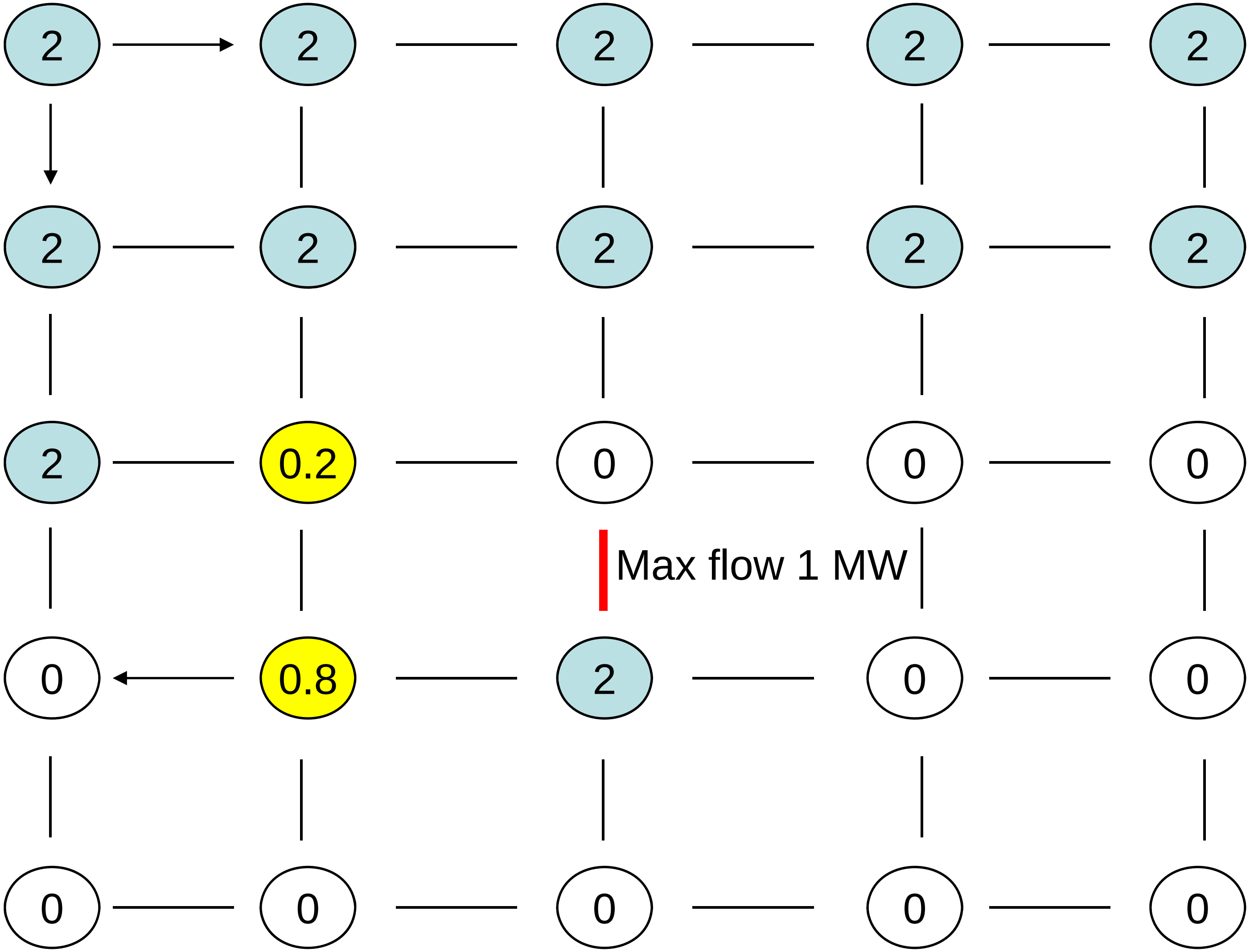
- No congestion: 1 price
  - Solution independent of market model
- One congested line and dispatching by nodal pricing: 15 different prices
  - Optimal dispatch, marginal pricing
- One congested line and dispatching by zonal pricing: 2 prices
  - Nord Pool type of market splitting

1. Generation – No congestion. Total cost = 169 €



2	2	2	2	2
2	2	2	2	2
2	2	1	0	0
0	0	0	0	0
0	0	0	0	0

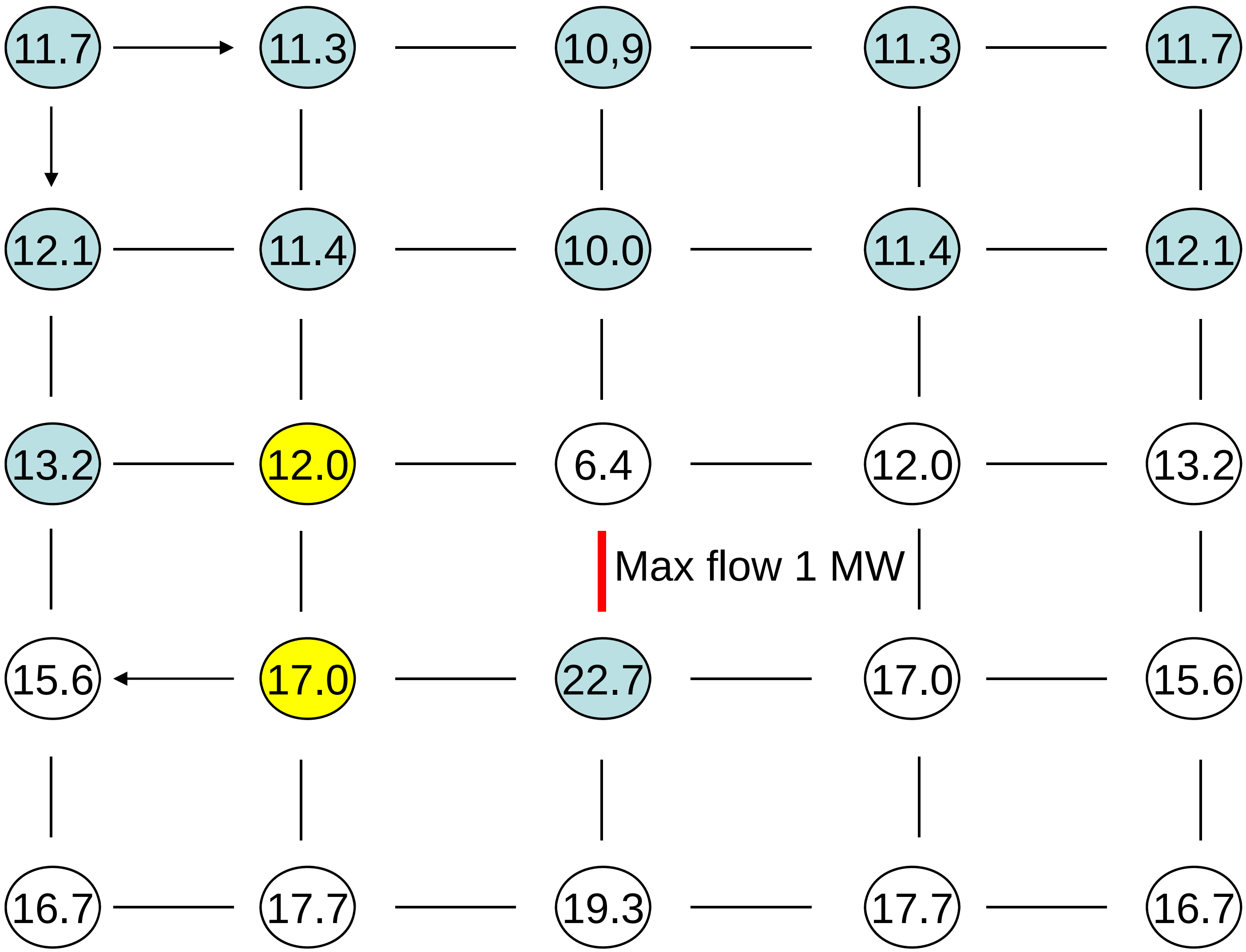
2. Generation – One congested line. Total cost = 184 €



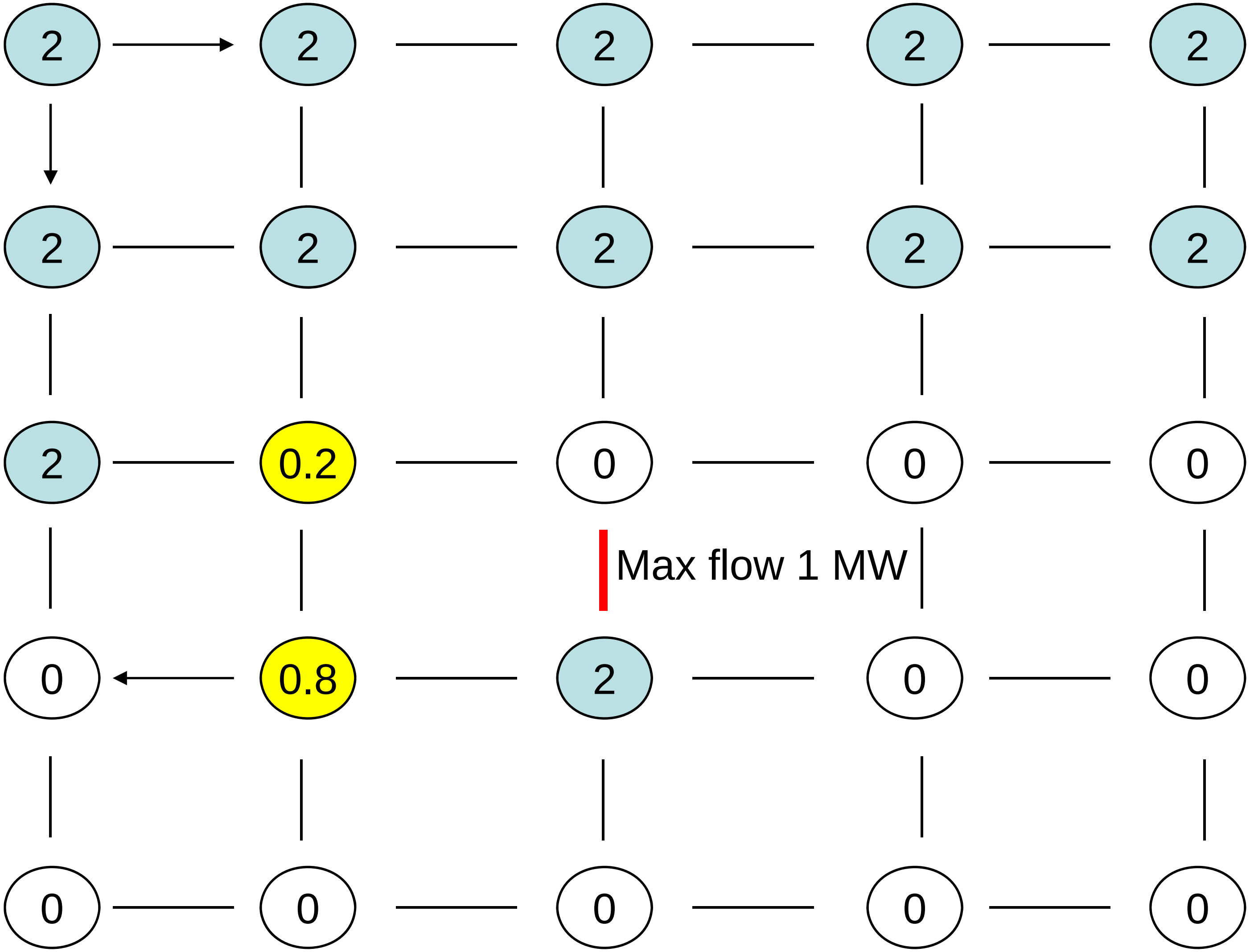
2	2	2	2	2
2	2	2	2	2
2	0.2	0	0	0
0	0.8	2	0	0
0	0	0	0	0

Max flow 1 MW

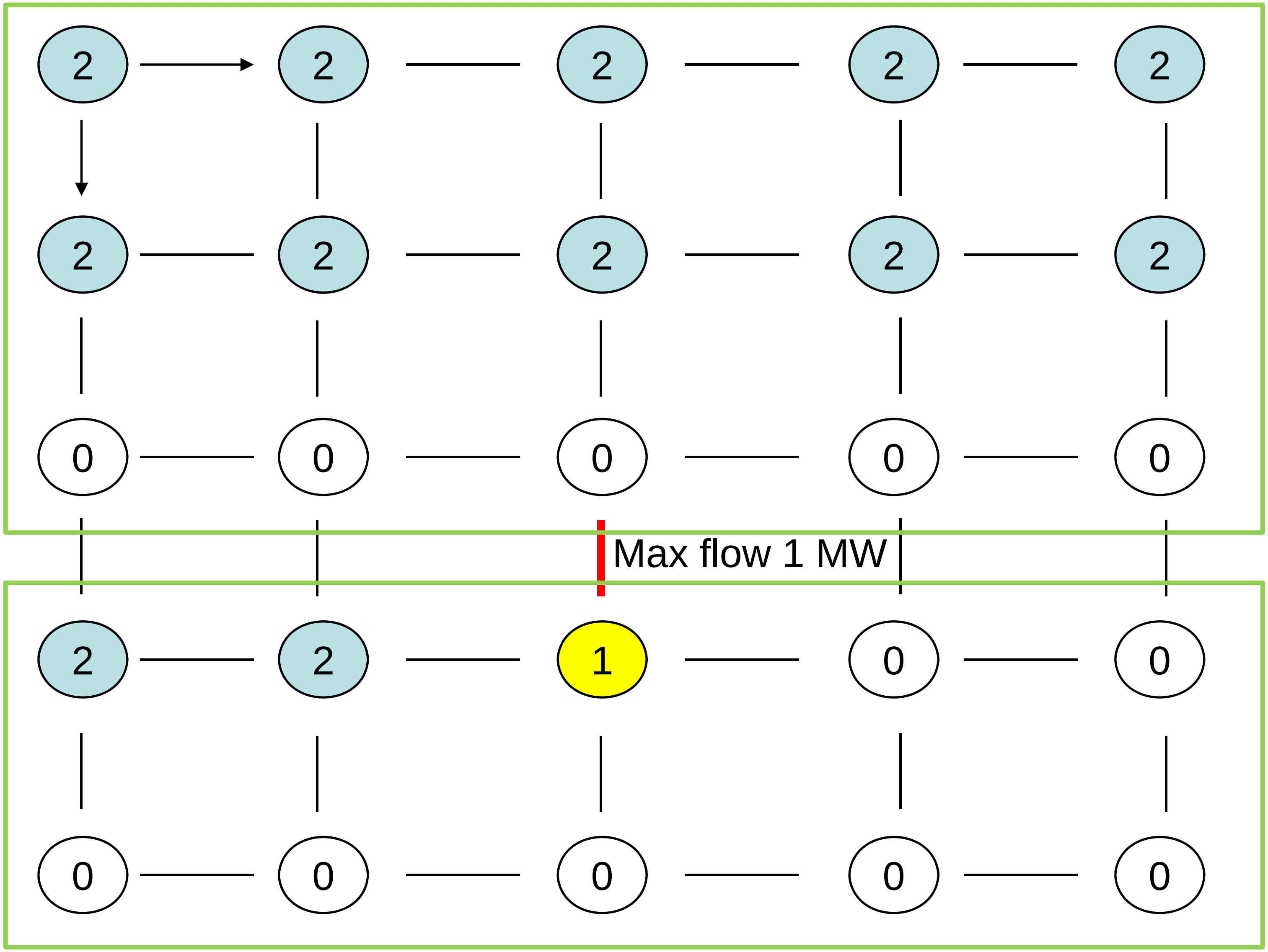
2. Prices – One congested line. Total cost = 184 €



2. Generation – One congested line. Total cost = 184 €



3. Generation – One congested line. Total cost = 194 €



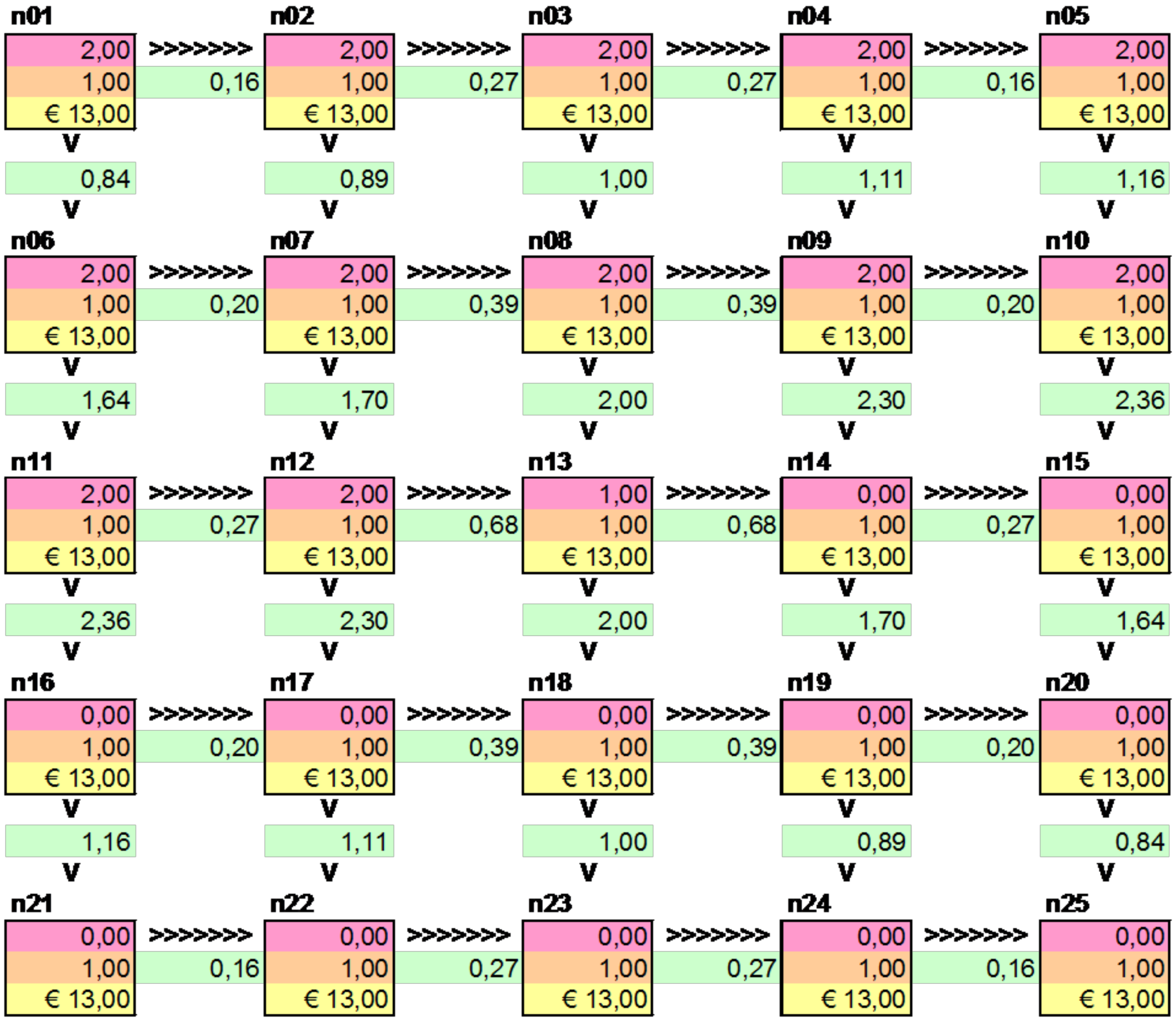
Zonal pricing

- With zonal pricing, TSOs must restrict total cross-border flow to 5 MW or less (sum of five lines)
- With nodal pricing (with optimal dispatch) the cross border flow is 7.2 MW, leading to 5% lower costs
- All flow and node prices can be found in appendix

Appendix

Case 1

Nodal pricing in a simple electricity network



n01		**n02**		**n03**		**n04**		**n05**
2,00	>>>>>>>	2,00	>>>>>>>	2,00	>>>>>>>	2,00	>>>>>>>	2,00
1,00	0,16	1,00	0,27	1,00	0,27	1,00	0,16	1,00
€ 13,00		€ 13,00		€ 13,00		€ 13,00		€ 13,00
V		V		V		V		V
0,84		0,89		1,00		1,11		1,16
V		V		V		V		V
n06		**n07**		**n08**		**n09**		**n10**
2,00	>>>>>>>	2,00	>>>>>>>	2,00	>>>>>>>	2,00	>>>>>>>	2,00
1,00	0,20	1,00	0,39	1,00	0,39	1,00	0,20	1,00
€ 13,00		€ 13,00		€ 13,00		€ 13,00		€ 13,00
V		V		V		V		V
1,64		1,70		2,00		2,30		2,36
V		V		V		V		V
n11		**n12**		**n13**		**n14**		**n15**
2,00	>>>>>>>	2,00	>>>>>>>	1,00	>>>>>>>	0,00	>>>>>>>	0,00
1,00	0,27	1,00	0,68	1,00	0,68	1,00	0,27	1,00
€ 13,00		€ 13,00		€ 13,00		€ 13,00		€ 13,00
V		V		V		V		V
2,36		2,30		2,00		1,70		1,64
V		V		V		V		V
n16		**n17**		**n18**		**n19**		**n20**
0,00	>>>>>>>	0,00	>>>>>>>	0,00	>>>>>>>	0,00	>>>>>>>	0,00
1,00	0,20	1,00	0,39	1,00	0,39	1,00	0,20	1,00
€ 13,00		€ 13,00		€ 13,00		€ 13,00		€ 13,00
V		V		V		V		V
1,16		1,11		1,00		0,89		0,84
V		V		V		V		V
n21		**n22**		**n23**		**n24**		**n25**
0,00	>>>>>>>	0,00	>>>>>>>	0,00	>>>>>>>	0,00	>>>>>>>	0,00
1,00	0,16	1,00	0,27	1,00	0,27	1,00	0,16	1,00
€ 13,00		€ 13,00		€ 13,00		€ 13,00		€ 13,00

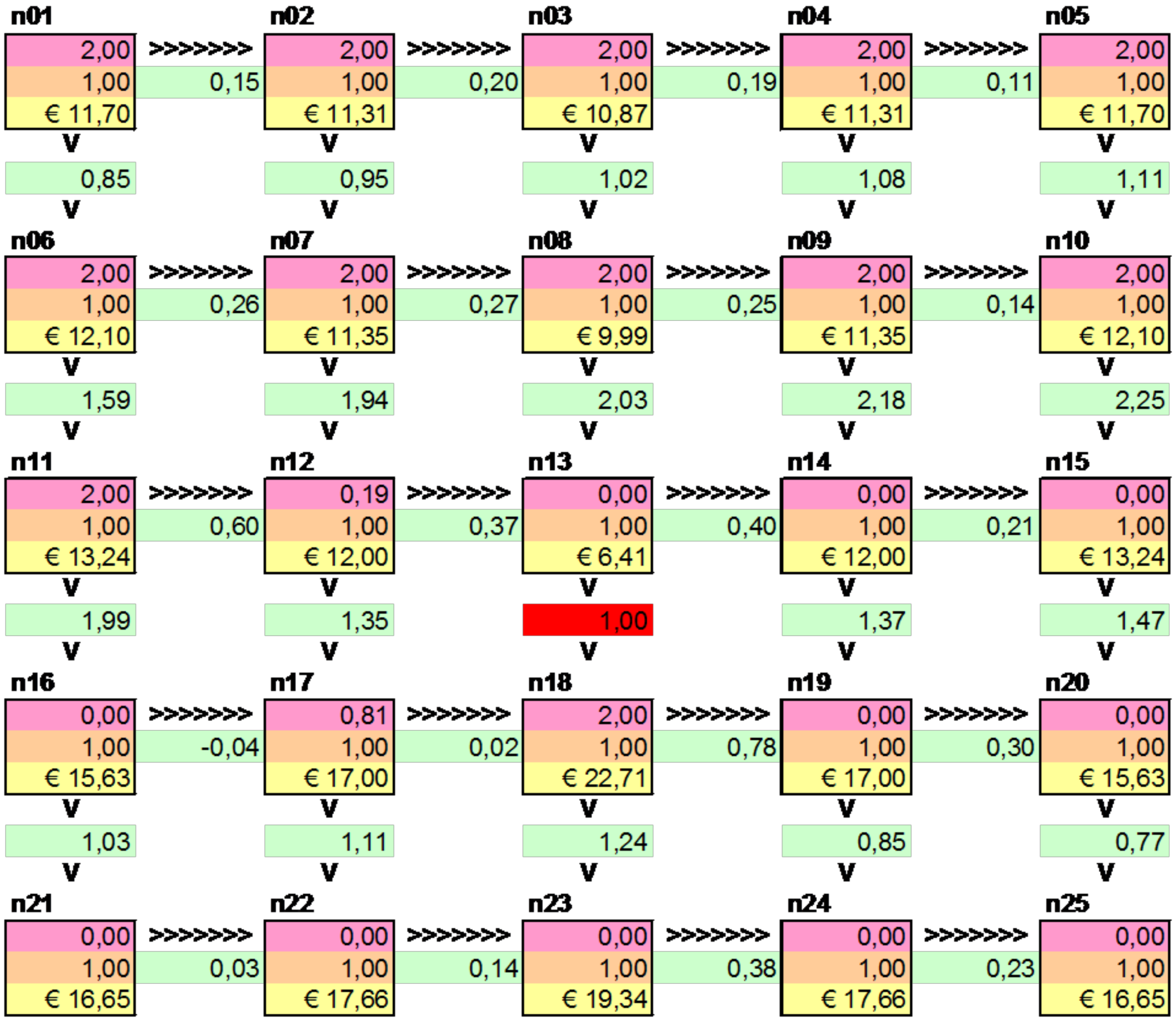
Generation
Demand
Nodal prices
Transmission

Total costs
€ 169,00

No losses
No capacity constrains

Case 2

Nodal pricing in a simple electricity network



n01		**n02**		**n03**		**n04**		**n05**
2,00	>>>>>>>	2,00	>>>>>>>	2,00	>>>>>>>	2,00	>>>>>>>	2,00
1,00	0,15	1,00	0,20	1,00	0,19	1,00	0,11	1,00
€ 11,70		€ 11,31		€ 10,87		€ 11,31		€ 11,70
V		V		V		V		V
0,85		0,95		1,02		1,08		1,11
V		V		V		V		V
n06		**n07**		**n08**		**n09**		**n10**
2,00	>>>>>>>	2,00	>>>>>>>	2,00	>>>>>>>	2,00	>>>>>>>	2,00
1,00	0,26	1,00	0,27	1,00	0,25	1,00	0,14	1,00
€ 12,10		€ 11,35		€ 9,99		€ 11,35		€ 12,10
V		V		V		V		V
1,59		1,94		2,03		2,18		2,25
V		V		V		V		V
n11		**n12**		**n13**		**n14**		**n15**
2,00	>>>>>>>	0,19	>>>>>>>	0,00	>>>>>>>	0,00	>>>>>>>	0,00
1,00	0,60	1,00	0,37	1,00	0,40	1,00	0,21	1,00
€ 13,24		€ 12,00		€ 6,41		€ 12,00		€ 13,24
V		V		V		V		V
1,99		1,35		1,00		1,37		1,47
V		V		V		V		V
n16		**n17**		**n18**		**n19**		**n20**
0,00	>>>>>>>	0,81	>>>>>>>	2,00	>>>>>>>	0,00	>>>>>>>	0,00
1,00	-0,04	1,00	0,02	1,00	0,78	1,00	0,30	1,00
€ 15,63		€ 17,00		€ 22,71		€ 17,00		€ 15,63
V		V		V		V		V
1,03		1,11		1,24		0,85		0,77
V		V		V		V		V
n21		**n22**		**n23**		**n24**		**n25**
0,00	>>>>>>>	0,00	>>>>>>>	0,00	>>>>>>>	0,00	>>>>>>>	0,00
1,00	0,03	1,00	0,14	1,00	0,38	1,00	0,23	1,00
€ 16,65		€ 17,66		€ 19,34		€ 17,66		€ 16,65

Generation
Demand
Nodal prices
Transmission

Total costs
€ 184,07

No losses
Capacity constraints: N13->N18: 1