Norwegian Hydro Power as Balancing Resource for Europe
Market and Grid Impacts

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Prof. Magnus Korpås
Department of Electric Power Engineering
Norwegian University of Science and Technology
Some facts about the Norwegian hydropower system
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??

<table>
<thead>
<tr>
<th></th>
<th>BLÅSJØ</th>
<th>HOME BATTERY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capacity (kWh)</td>
<td>8 000 000 000</td>
<td>10</td>
</tr>
<tr>
<td>Installation cost ($)</td>
<td>-</td>
<td>3,500</td>
</tr>
<tr>
<td>Lifetime (years)</td>
<td>∞</td>
<td>10</td>
</tr>
</tbody>
</table>

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)

- Produksjon NO
- Forbruk NO
- Eksport NO->utlandet
- Eksport NO->DK
- Pris NO
- Pris DK

Map of Norway and Denmark
Exchange in the long term (months to years)
Reservoir filling (%) in Norway up to 2012

max
median
min
Norwegian hydro inflow for 75 years
Wind power and hydro power in Norway: A good match

![Graph showing yearly production and energy input over years and weeks]

- Yearly production (%)
- (% of yearly energy input)

Wind and Hydro: Inflow and Consumption

Norwegian University of Science and Technology
The water courses are complex

Detailed modelling is required to capture the hydro characteristics and thus the "green battery" potential.
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

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
Houston, we have a problem .. challenge!

Source: Aigner (NTNU)
...and a whole lotta solutions!

Balancing load, wind & solar

- Norwegian hydro
  - Fast response
  - Large storages
  - Big investment decisions
  - European collaboration

- Local pumped storage

Efficient power markets

- More flexible
  - Coal plants
  - Nuclear plants

- Strengthen the power grid across borders
  - Smarter use of energy
  - Interplay with district heating
  - Local storage

Flexible gas power
- OCGT
- CCGT
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 actively
- 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

December 2000 wind speeds, 2030 MW amounts

Power (% of installed capacity)

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

Source: Fraunhofer IWES
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

Are these returns sufficient?

Marginal costs of a new plant

Expected annual operating hours

Ordered price duration curve for the planning horizon

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 pumping)
- 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

Source: Jaehnert, Korpås, Doorman (NTNU)
Norwegian reservoir handling

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

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

Extending the EMPS market model with a capacity market
Investment algorithm for transmission grid development

- Initial capacities
  - Transmission
  - Production

- EMPS

- Simulated prices

- Profitability investments

- Possible investments

- Forecast
  - Consumption
  - Fuel costs
  - ...

- New capacities
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

Scheduled Prod. = Cons.

System Imbalances
- Forecast error
  - Prod./Cons.
  - Outages
  - Gen./Trans./Load

Frequency deviations

Reserve activation

Security of supply

Source: www.fourmilab.ch
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](http://www.50hertz.com)
..but forecast horizon and geographical spread are essential

Geographical smoothing of forecast errors based on 40 German wind farms

Simulated forecast error [GW] in Northern Europe in 2020

Source: energy & meteo systems, IEA Wind

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
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 7km x 7Km and 15 min
► The installed wind power capacity is scaled up to meet the assumed installed capacity in 2030.
Market model structure

**Input**
- Power plant data
- Transmission system data
- Demand, Ex- & Import
- Hydro inflow, Wind Speed

**Model**

**Day-ahead market**
- System dispatch
- Water values
- Area prices

**Reserve procurement**
- Reserve requirements:
  - per control area
  - minimum share

**System balancing**
- System imbalance:
  - Demand forecast error
  - Wind forecast error

- System redispatch
- Reserve capacity
- Water values
- Area prices

**Output**

**EMPS**
- Total production cost
- Area prices
- Optimal generation dispatch
- Transmission dispatch

**IRiE**
- Reserve procurement cost
- Available reserve capacity

- System balancing cost
- Activation / exchange of balancing energy

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EMPS  EFI's Multi-area Power-market Simulator
IRiE  Integrated Regulating power market in Europe

Norwegian University of Science and Technology
IRiE - Reserve procurement

Least cost system redispatch in order to fulfil given reserve requirements

- Formulated as mixed-integer problem
- State-up state of thermal units defined as binary variable
- Initial solution of relaxed LP
- Consecutive solution as MIP
- Consideration of start-up costs for thermal units
- Losses due to reduced efficiency for thermal and hydro units
- Transmission capacity necessary for the cross-border exchange of reserve capacity
IRiE - System balancing

- Division in activation of spinning / non-spinning reserves
- Transmission capacity necessary for the cross-border exchange of balancing energy
- Formulated as linear problem
- Netting of counteracting imbalances

Least cost activation of regulating reserves in order to restore the system balance
Country wise annual balancing reserve allocation (GWh/yr)

(a) 2010

(b) 2020

Source: Jaehnert (NTNU)
Total balancing market costs for different wind forecast horizons

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-optimizing day-ahead scheduels and reserve procurements based on forecasts
- Scenarios for load, generation and grid capacity year 2020 and 2030
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

[Diagram showing water value, reservoir level, and power output from small and large scale thermal production systems.]
Simulation Procedure

**Input data for Day-ahead dispatch**
- Power flow case description
- Generator capacities
- Generator cost curves (marginal cost)
- Reservoir levels (Hydro)
- Reserve requirements

**Time dependent**
- Load series
- Wind series
- Inflow (hydro)
- Water values

**Day-Ahead Market & Reserve Procurement**

**Scheduled Dispatch**

**System Balancing**

**Input data for Real-time dispatch**
- Real-time Imbalance Scenario
  - Demand forecast error
  - Wind forecast error

**Results**
- Production cost
- Optimal production dispatch
- Optimal HVDC lines flow
- Power Exchange between areas

**Results**
- Balancing Cost
- Optimal dispatch of regulating objects
- Optimal exchange of balancing services.
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
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)

<table>
<thead>
<tr>
<th>Year</th>
<th>Reserve procurement costs</th>
<th>Balance settlement costs</th>
</tr>
</thead>
<tbody>
<tr>
<td>2030</td>
<td>No integration</td>
<td>Full integration</td>
</tr>
</tbody>
</table>

Source: Farahmand (NTNU/SINTEF)
Significant savings are achieved with integrated intra-day markets

Total annual balancing costs

- 2010: Without intraday 230 Mil. EURO
- 2020: Without intraday 500 Mil. EURO
- 2010: With intraday 130 Mil. EURO
- 2020: With intraday 100 Mil. EURO

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
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)
## Scenario 12 new power plants

<table>
<thead>
<tr>
<th>Case</th>
<th>Kraftverk</th>
<th>Kapasitet (MW)</th>
<th>Øvre magasin¹</th>
<th>Nedre magasin²</th>
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<tbody>
<tr>
<td>A2</td>
<td>Pumpekraftverk Tonstad</td>
<td>1400</td>
<td>Nesjen (14 cm/h)</td>
<td>Sirdalsvatn (3 cm/h)</td>
</tr>
<tr>
<td>B3</td>
<td>Pumpekraftverk Holen</td>
<td>700</td>
<td>Urarvatn (8 cm/h)</td>
<td>Bossvatn (8 cm/h)</td>
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<tr>
<td>B6a</td>
<td>Pumpekraftverk Kvilldal</td>
<td>1400</td>
<td>Blåsjø (7 cm/h)</td>
<td>Suldalsvatn (4 cm/h)</td>
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<td>B7a</td>
<td>Effektverk Jøsenfjorden</td>
<td>1400</td>
<td>Blåsjø (7 cm/h)</td>
<td>Jøsenfjorden (sjø)</td>
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<tr>
<td>C1</td>
<td>Pumpekraftverk Tinnsjø</td>
<td>1000</td>
<td>Møsvatn (2 cm/h)</td>
<td>Tinnsjø (1 cm/h)</td>
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<tr>
<td>D1</td>
<td>Effektverk Lysebotn</td>
<td>1400</td>
<td>Lyngsvatn (9 cm/h)</td>
<td>Lysefjorden (sjø)</td>
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<tr>
<td>E1</td>
<td>Effektverk Mauranger</td>
<td>400</td>
<td>Juklavatn (14 cm/h)</td>
<td>Hardangerfj. (sjø)</td>
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<tr>
<td>E2</td>
<td>Effektverk Oksla</td>
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<td>Ringedalsvatn (12 cm/h)</td>
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<tr>
<td>G2</td>
<td>Effektverk Tyin</td>
<td>700</td>
<td>Tyin (1 cm/h)</td>
<td>Årdalsvatnet³</td>
</tr>
</tbody>
</table>

| Sum ny effektkapasitet | 11 200 |

¹Vannstandsreduksjon i parentes.
²Vannstandsøkning i parentes.
³Mangler 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
   – CO₂ price 93.9 €/ton

2. 4DS – IEA New Policy Scenario:
   – Gas price 34.8 €/MWh
   – CO₂ price 35.2 €/ton

3. Low Gas price Europe:
   – Gas price 19.7 €/MWh (USA level)
   – CO₂ 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

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

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

Natural gas: \((p_{ng} + p_{CO2} \cdot e_{ng})/\eta_{ng}\)

Pumped hydro: \(p_{pump}/\eta_{ph}\)
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:  \[
LCPG_{ng} = \frac{i_{ng} \cdot (\delta_{ng,r} + OM_{ng}) - p_{cap}}{\alpha_{ng} \cdot T_{ng}} + \left( p_{ng} + p_{CO_2} \cdot e_{ng} \right) \eta_{ng}
\]
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

![Graph showing the sensitivity of LCPG to pumping price and cable discount rate. The graph plots LCPG in €/MWh against pumping price in €/MWh for different load factors and cable discount rates. The lines represent different technologies: OCGT-1, OCGT-2, CCGT, and Pumped Hydro (a) and (b).]
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 today's 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
<table>
<thead>
<tr>
<th>Parameter</th>
<th>CCGT</th>
<th>OCGT-1 (Aeroderivative)</th>
<th>OCGT-2 (F-class)</th>
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<td>$i_{ng}$ [€/kW]</td>
<td>718</td>
<td>705</td>
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<tr>
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<td>25</td>
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<tr>
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<tr>
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<td>35</td>
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<tr>
<td>$\alpha_{ng}$ [%]</td>
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<td>91.9</td>
</tr>
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<table>
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<th>SCG and GR</th>
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<td>$i_{cable}$ [€/kW]</td>
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<tr>
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<tr>
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<td>$n_{grid}$ [yr]</td>
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