2019IDSSMITEI
Decision Support Models for Low-Carbon Electric Power Systems

Transmission Expansion Planning

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Massachusetts Institute of Technology (MIT). January 2019
Motivation

• To understand why the transmission plays an important role in renewable integration

• To give an indication about what it is possible to state with a decision tool
  – Capabilities and limitations

• To become familiar with transmission network expansion modeling techniques

• To give the mathematical foundation
Electric System. Activities, businesses and markets

Activities:
- Renewable energy
  - PV solar
  - Wind
  - Hydroelectric power plant
- Thermal energy
  - Nuclear
  - Thermal power plants

Energy Generation from Transmission, transformation and Distribution networks to Energy Consumption: Customers
- Household
- Residential
- Industrial
- SMEs / Retail

Business:
- Power Generation Developers
- Transmission System Operator (TSO)
- Distribution System Operator (DSO)
- Energy Retail Business

Market:
- Liberalise
- Regulated
- Liberalise

Source: Iberdrola
Electric System. Physical layout

Color Key:
- Red: Generation
- Blue: Transmission
- Green: Distribution
- Black: Customer

Generating Station
- Generating Step Up Transformer

Transmission lines
- 765, 500, 345, 230, and 138 kV

Substation Step Down Transformer

Transmission Customer
- 138kV or 230kV

Subtransmission Customer
- 26kV and 69kV

Primary Customer
- 13kV and 4kV

Secondary Customer
- 120V and 240V

https://upload.wikimedia.org/wikipedia/commons/4/41/Electricity_grid_simple-_North_America.svg
References

- Latorre G; Cruz RD; Areiza JM; et al. Classification of publications and models on transmission expansion planning. IEEE Transactions on Power Systems (18):2 938-946 May 2003. 10.1109/TPWRS.2003.811168
References


• S. Binato, M.V.F. Pereira, and S. Granville *A New Benders Decomposition Approach to Solve Power Transmission Network Design Problems* IEEE Transactions on Power Systems 16(2) 235-240 May 2001 10.1109/59.918292


The future of system operations: The new 50Hertz Transmission Control Center

http://www.youtube.com/watch?v=uE49sQMWekg

TenneT network planning - to guarantee system stability

https://youtu.be/P5No16dyJN4
Drivers for investing

• Reliability

• Economic efficiency
  – Reduce network losses
  – Mitigate capacity constraints (congestion), expand electricity markets or mitigate market power
  – Avoidance/postponement of generation investments

• Generation connection of new (conventional) power plants

• Meet RES policy targets (solar and wind generation)
  – Winter Package: 40% emission reductions, 30% improvement in energy efficiency and 27% increase in renewables by 2030
  – 20-20-20 target set by the EU: 20% emission reductions, 20% improvement in energy efficiency and 20% increase in renewables by 2020
  – National Renewable Energy Action Plans (NREAP)
USA Projected Transmission Investment Opportunities

Projected U.S.
Investments through
2030:
$120-160 billion/decade

Ultimately
Open to Non-
Incumbents?

Renewable
Generation
Additions

Coal Plant
Retirement and
Clean Power Plan

Aging Facilities

Reliability
Upgrades, Gen
Interconnection, Load Serving

Interregional
Buildout

Pockets of High
Load Growth
(e.g., Oil & Gas
Development)

http://www.brattle.co.uk/industry/electric-power/82-transmission
USA Historical and Projected Transmission Investments


http://www.brattle.co.uk/industry/electric-power/82-transmission
USA Historical and Projected Transmission Investments

The graph shows the historical and projected transmission investments in the USA from 2012 to 2021. The investments are measured in billion dollars. The actual investments from 2012 to 2017 are shown on the left side, with projections from 2018 to 2021 on the right side. The investments have increased over the years, with a projected increase in 2021 compared to 2012.
Maine, USA

Northeast Energy Link concept plan

The Northeast Energy Link transmission line would connect to existing lines in eastern Maine and Canada and carry renewable energy to the New England power grid in Massachusetts.

- Quebec Hydro, Wind
- Newfoundland Labrador Hydro
- New Brunswick Wind, Hydro
- P.E.I. Wind
- Nova Scotia Wind, Hydro

Maine Wind

- Fredericton
- Nova Scotia Wind, Hydro

Proposed Northeast Energy Link Transmission
- Existing Northeast Reliability Interconnect Transmission
- Existing Maine Electric Power Company Transmission
- Potential generation source

http://www.mainerei.com/project-map.html
New England Clean Energy Connect
USA Renewable Portfolio Standards

RPS Policies Exist in 29 States and DC
Apply to 56% of Total U.S. Retail Electricity Sales

Source: Berkeley Lab (July 2017)
Notes: In addition to the RPS policies shown on this map, voluntary renewable energy goals exist in a number of U.S. states, and both mandatory RPS policies and non-binding goals exist among U.S. territories (American Samoa, Guam, Puerto Rico, US Virgin Islands).
Land Based and Offshore Annual Average Wind Speed at 100 Meters

Major PV and CSP projects in the US
ERCOT. Locational marginal prices

http://www.ercot.com/content/cdr/contours/rtmLmpHg.html
ERCOT. Locational marginal prices

http://www.ercot.com/content/cdr/contours/rtmLmpHg.html
MISO. Locational marginal prices
(Ten-Year Network Development Plan) TYNDP 2018


Under construction
In permitting
Planned but not yet permitting
Under consideration
TYNDP 2016 Outcomes

- €150bn investments, of which 70-80 by 2030
- 1 to 2 €/MWh impact on bills due to transmission investment
- 1.5 to 5 €/MWh potential reduction in wholesale prices
- 45 to 60% RES across 4 visions for 2030
- 50% to 80% emissions cut depending on the vision
- 40% reduction in congestion hours
Projects of Common Interest (PCI)

Selected on the basis of five criteria:

1. have a **significant impact on at least two EU countries**
2. **enhance market integration** and contribute to the integration of EU countries' networks
3. **increase competition on energy markets** by offering alternatives to consumers
4. **enhance security of supply**
5. **contribute to the EU's energy and climate goals.** They should facilitate the integration of an increasing share of energy from variable renewable energy sources.

Map of European wind farms

https://setis.ec.europa.eu/sites/default/files/report_graphs/farm_locations_0.png
Off-shore wind farms in the North Sea

London Array
• An offshore area of 100 km²
• 175 wind turbines
• Two offshore substations
• Nearly 450 km of offshore cabling
• One onshore substation
• 630 MW of capacity
• 1 GW projected
• 245 km²

East Anglia One
(http://eastangliaone.eastangliawind.com/)
• An offshore area of 300 km²
• 240 wind turbines
• Two offshore converter substations
• One onshore converter substation
• 1200 MW of capacity

Dogger Bank
• 9 GW target

http://www.4coffshore.com/offshorewind/
Projects awarded Contracts for Difference in UK (2015)

- **Walney Extension**: 660 MW, Irish Sea 10km WSW off the Walney Island coast in Cumbria
- **Beatrice**: 664 MW, Outer Moray Firth, Scotland
- **Neart na Gaoithe (NNG)**: 448MW, Northern North Sea (Forth), Scotland
- **Hornsea 1**: 1200 MW, North Sea, off the Yorkshire coast
- **Burbo Bank Extension**: 258 MW, Liverpool Bay
- **Dudgeon**: 402 MW, The Wash north of Cromer, Norfolk
- **East Anglia ONE**: 714MW, Southern North Sea (Thames), East of England

Offshore wind (UK) map – May 2015

(c) Crown Estate
Western Link, UK
Transmission Expansion Planning

Spanish Grid

1988

1997
Influence of wind connection on transmission planning

Wind Power connection and operation becomes one of the most significant motivations for the Transmission Network Plan 2002-2011: Lack of coordination leads to inefficiency

Source: J.F. Alonso, System Operation Perspective: Connection and Operation Aspects, REE, 2006
Spanish high voltage transmission network (1990-2016)
2. Simple TEP models

Simple TEP models
Centralized TEP model

\[
\begin{align*}
\text{min} & \quad \sum_{ij} f_{ij}' IC_{ij} + \sum_t v_t P_t + \sum_i v' ENS_i \\
\sum_i P_t + \sum_j F_{ji} - \sum_j F_{ij} + ENS_i &= D_i \quad \forall i \\
F_{ij} - \frac{\theta_i - \theta_j}{X_{ij}} S_B &= 0 \quad \forall ij \\
-\bar{F}_{ij}'(1 - IC_{ij}) &\leq F_{ij} - \frac{\theta_i - \theta_j}{X_{ij}} S_B \leq \bar{F}_{ij}'(1 - IC_{ij}) \quad \forall ij \\
-\bar{F}_{ij} &\leq F_{ij} \leq \bar{F}_{ij} \quad \forall ij \\
-\bar{F}_{ij} IC_{ij} &\leq F_{ij} \leq \bar{F}_{ij} IC_{ij} \quad \forall ij \\
\theta_i &\text{ free, } \theta_i^* = 0 \quad \forall i \\
0 &\leq ENS_i \leq D_i \quad \forall i \\
0 &\leq P_t \leq \bar{P} \quad \forall t \\
IC_{ij} &\in \{0,1\} \quad \forall ij
\end{align*}
\]

- Transmission investment cost + thermal variable costs + ENS cost
- Generation and load balance for each node
- DC linearized load flow for existing and candidate lines
- Flow limits for existing & candidate lines. Reference voltage angle
- Thermal operating bounds
- Investment decisions
Market TEP model

- No longer exists coordination between generation operation and TEP
- Conceptual solution of the market equilibrium with network expansion decisions
  - TSO decides first: Proactive investment
    - Stackelberg leader-multi-follower game stated as bilevel optimization
  - TSO reacts to generation investments: Reactive investment
- Financial Transmission Rights (FTR) can help in solving this dilemma
**TSO (Transmission System Operator) optimization problem**

- **O.F.:** Investment cost minimization and computation of nodal prices
- **Constraints:** load flow equations

\[
\min \sum_{ij} f'IC_{ij} + \sum_{i} v'E_{NS_i} \]

\[
\sum_{t \in i} P_t + \sum_{j} F_{ji} - \sum_{j} F_{ij} + ENS_{i} = D_i \quad \forall i
\]

\[
F_{ij} - \frac{\theta_i - \theta_j}{X_{ij}} S_B = 0 \quad \forall ij
\]

\[
-F_{ij}'(1 - IC_{ij}) \leq F_{ij} - \frac{\theta_i - \theta_j}{X_{ij}} S_B \leq F_{ij}'(1 - IC_{ij}) \quad \forall ij
\]

\[
-F_{ij} \leq F_{ij} \leq F_{ij} \quad \forall ij
\]

\[
-F_{ij}IC_{ij} \leq F_{ij} \leq F_{ij}IC_{ij} \quad \forall ij
\]

\[
\theta_i \text{ free, } \theta_{i^*} = 0
\]

\[
0 \leq ENS_{i} \leq D_i \quad \forall i
\]

\[
IC_{ij} \in \{0, 1\} \quad \forall ij
\]

**Transmission investment cost**

**Generation and load balance for each node**

**DC linearized load flow for existing and candidate lines**

**Flow limits for existing & candidate lines. Reference voltage angle**

**ENS bounds**

**Investment decisions**
GenCo profit maximization problem

- **O.F.: Maximize its profit** given nodal prices
- **Constraints:** generation operation

\[
\begin{align*}
\max & \sum_{i} \sum_{t \in i} \pi_i P_t - \sum_{t} v_t P_t \\
0 & \leq P_t \leq \bar{P}_t \quad \forall t
\end{align*}
\]
GenCos market equilibrium model

- Each company solves independently its own profit maximization problem

Gen Company 1
\[
\max \sum_i \sum_{t \in i} \pi_i P_t - \sum_t v_t P_t \\
0 \leq P_t \leq \overline{P}_t \quad \forall t
\]

Gen Company e
\[
\max \sum_i \sum_{t \in i} \pi_i P_t - \sum_t v_t P_t \\
0 \leq P_t \leq \overline{P}_t \quad \forall t
\]

Gen Company E
\[
\max \sum_i \sum_{t \in i} \pi_i P_t - \sum_t v_t P_t \\
0 \leq P_t \leq \overline{P}_t \quad \forall t
\]
**Overall GEP + TEP**

**Bilevel optimization**

**TSO**

\[
\min \sum_{ij} f'_{ij} IC_{ij} + \sum_{i} v' ENS_{i}
\]

\[
\sum_{t \in i} P_t + \sum_{j} F_{ji} - \sum_{j} F_{ij} + ENS_{i} = D_i : \pi_i \quad \forall i
\]

\[
F_{ij} - \frac{\theta_i - \theta_j}{X_{ij}} S_B = 0 \quad \forall ij
\]

\[
-F'(1 - IC_{ij}) \leq F_{ij} - \frac{\theta_i - \theta_j}{X_{ij}} S_B \leq F'(1 - IC_{ij}) \quad \forall ij
\]

\[
-F_{ij} \leq F_{ij} \leq F_{ij} \quad \forall ij
\]

\[
-F_{ij} IC_{ij} \leq F_{ij} \leq F_{ij} IC_{ij} \quad \forall ij
\]

\[
\theta_i \text{ free, } \theta_j = 0
\]

\[
0 \leq ENS_{ij} \leq D_i \quad \forall i
\]

\[
IC_{ij} \in \{0, 1\} \quad \forall ij
\]

---

**Gen Company 1**

\[
\max \sum_{i} \sum_{t \in i} \pi_i P_t - \sum_{t} v_t P_t
\]

\[
0 \leq P_t \leq P_t \quad \forall t
\]

**Gen Company e**

\[
\max \sum_{i} \sum_{t \in i} \pi_i P_t - \sum_{t} v_t P_t
\]

\[
0 \leq P_t \leq P_t \quad \forall t
\]

**Gen Company E**

\[
\max \sum_{i} \sum_{t \in i} \pi_i P_t - \sum_{t} v_t P_t
\]

\[
0 \leq P_t \leq P_t \quad \forall t
\]
Modeling issues

1. Transmission Expansion Planning
2. Simple TEP models
3. **Modeling issues**
4. Prototype TEP. Mathematical formulation
5. Prototype TEP. Computer implementation
Challenges for Transmission Expansion Planning (TEP)

Stochastic complexity: weather conditions and human behaviors

Spatial complexity: Europe to smart cities

Temporal complexity: msec. to decades

Rise of the Smart City
Network planning functions

Functions

New liberalized market functions
(Open access)

Traditional regulated operation functions

Long term
Medium term
Short term

Scope

Transmission expansion planning
Selection and evaluation of network investments
Impact on market agents (GENCOs or ESCOs)
Evaluate system interconnections

• Transmission network expansion planning
• Selection and evaluation of network investments
• Impact on market agents (GENCOs or ESCOs)
• Evaluate system interconnections

• Studies about network performance
• Generation localization
• Adequacy assessment/reliability studies
• Network maintenance
• Operation planning

• Transmission right assessment
• Determine payment for the network use
• Allocate network costs
• Network remuneration studies
• Evaluate network contracts

• Check the viability of the generation and consumption dispatch
• Determine nodal marginal prices
• Identify and determine losses
• Identify and determine zonal or local ancillary services
• Decisions about network operation
TSO (Transmission System Operator) activities

Source: GARPUR Project. D1.1 State of the art on reliability assessment in power systems http://www.garpur-project.eu/deliverables
Time scopes

• **Long-term (tactical)** (5-10 years)
  – Specific decisions for network development
  – More detailed models are required
  – Analysis of proposed plans is the main objective

• **Very long-term (strategic)** (10-20 years)
  – Guidelines for network development
  – Simpler models are acceptable
  – New corridors are the main objective to determine
Characteristics of the TEP

- Very complex decision problem, with multiple criteria
- Important strategic decision. Decisions require very long building periods and have long book life
- Generation planning decisions strongly affect transmission planning decisions
  - Wind and solar far from load centers
- Generation operation decisions and constraints are a subset of the transmission expansion problem. Large-scale transmission planning problem
  - Large and correlated variations of renewable sources cause interdependency power flows in large regions
  - Spatial correlation in generation profiles (wind and solar)
  - Sudden temporal changes from one day to another
Why coordination between generation and expansion planning?

• Decisions are taken by independent entities
  – Private generation companies
  – Publicly owned transmission system operators

• With different periods in advance
  – Several years for generation investment
  – A decade for transmission investment
Proactive and reactive investment game

Figure 4.2: The proactive approach for generation-transmission investment game

Figure 4.3: The reactive approach for generation-transmission investment game
General Scope

- **Generation Expansion Planning (GEP) or Integrated Resource Planning (IRP)**
  - GEP included in the optimization: GEP+TEP
  - GEP as an external input
    - Single future scenario vs. uncertain GEP

Implies using methods to cope with non-random uncertainties (exogenous storylines/pathways/options)

**Positive public attitude**
- High environmental focus in population and business.
- Reduced energy consumption and demand for environmentally friendly products

**Positive future for high RES integration, but too low technology development rate. Mainly decentralized development**

**Slow tech development**
- No major technology break-throughs; gradual development of current technologies

**Indifferent public attitude**
- Low environmental focus in population and business.
- Higher energy consumption and no demand for environmentally friendly products or services

**Green**
- New technologies are available, but low interest to invest and use. Mainly centralized development, but with new technologies.

**Blue**
- Major break-throughs in several technologies, RES, grids, demand side

**Fast tech development**
- Major break-throughs in several technologies, RES, grids, demand side

**Red**
- Difficult future for high RES integration, Few new technologies are available, and low interest to invest. Mainly centralized development with traditional technologies

**Yellow**
- High environmental focus in population and business. Reduced energy consumption and demand for environmentally friendly products

- Positive future for high RES integration. Both market pull and technology push existing.

**Source:** SUSPLAN (http://www.susplan.eu/) Planning for Sustainability
Future storylines for SET-Nav project

Pathway analysis: Pathway definition / Storylines

- heterogeneous actors
- coordination (beyond markets)
- digitalization (open IP)
- regulatory change
- disrupt incumbents

cooperation

Diversification

Directed vision

Decentralisation

Localization

National champions

Entrenchment

path dependency

- EU/state-directed
- shared vision
- strong EU policy framework

- utilities & incumbents
- regulatory capture
- low transition costs
Future storylines for TYNDP 2018

- Best Estimate
  - Merit order switch in 2025
    - Distributed Generation
      - 19% 15%
      - 9% 1%
    - The EU CO Scenario
      - 18% 8%
      - 5% 0%
  - Sustainable Transition
    - 20% 8%
    - 3% 0%
- Best Estimate
  - Distributed Generation
    - 27% 25%
    - 13% 1%
  - Global Climate Action
    - 36% 21%
    - 9% 3%
  - Sustainable Transition
    - 29% 12%
    - 5% 0%

- External from European Commission
- ENTSO-E/ENTSOG Scenario
- System share of wind
- System share of solar power
- Biomethane production share of demand
- Power-to-gas share of demand
Scenarios of uncertainty

- **Long term (some of them are non-random –non repeatable–)**
  - Electricity demand growth. Macroeconomic data
  - Inflation and discount rate
  - Demand side management (DSM) programs
  - **Location of generation plants (CCS plants? CSP generation?)**
  - Intermittent generation capacity
  - Fuel and CO2 prices
  - Public opinion (No nukes?)
  - Available transmission technologies

- **Medium term (random –repeatable–)**
  - Climate conditions (hydro inflows, wind, sun, temperature)
  - Contingencies (availability of generation and network elements)
  - System operation for several snapshots representative of the situations that may occur over the horizon year (Peak/Off-peak? Winter/Summer?). Possible use of clustering techniques
Operation scenarios/uncertainties

- **Detail of the load curve**
  - Hourly (8760h)
  - Less than hourly detail: snapshots (reasonable number: 100 to 1000) obtained by sampling/enumeration/clustering techniques
    - Time-independent snapshots
    - Sequential snapshots

- Which ones?
  - Peak/Off-peak? Winter/Summer?

Necessary if inter-temporal constraints are included in system operation (i.e., storage hydro, CAES, thermal up/down ramps)
Alternatives/Decisions

• Types of candidates
  – Upgrades to existing corridors or installation of new ones (incremental grid)
  – Upgrades with some long-distance interconnections (hybrid)
  – SuperGrid

• Candidate definition
  – Proposed by the model vs. externally provided

• Technology to be used
  – HVAC
  – HVDC

  – FACTS: Implies using at least a DCLF
Modeling aspects. Network size

- Number of nodes:
  - Small (10s of nodes): useful only for tests vs. Medium (100s of nodes) vs. Large (1000s of nodes)
    - Automatic network reduction techniques
  - Incremental modeling
    - A zonal network can determine the rough capacity to be added to corridors
    - A nodal network decides the exact lines
Modeling aspects. Network

- **Load flow**
  - ACLF
  - DCLF
  - Hybrid model (DC on existing lines and transportation on all/parallel candidate lines)
  - 1st Kirchhoff’s law. Transportation

- **Ohmic losses**
  - Exact vs. approximated (piecewise linear, % of flow) vs. ignored

- **Networks operating limits**
  - Line: thermal limit

- **Line switching. Network emergency operation**, e.g., tie and untie, substation reconfiguration
Criteria/Objectives

• Enable a low-cost operation of the system
• Enable a high level of security of supply
• Contribute to a sustainable energy supply
• Facilitate grid access to all market participants
• Contribute to internal market integration, facilitate competition and harmonization
• Contribute to energy efficiency of the system
Multicriteria Decision Making (MCDM)

Criteria

Costs

Environment

Market integration

Exogenous factors

Attributes

Investment (CapEx) and operation cost (OpEx)

Financial effort. Cash flow

Environmental impact

RES integration

Hours of market splitting

Social acceptance

Geopolitical risk

Costs

Environment

Market integration

Exogenous factors

Criteria Attributes

Exogenous factors

Costs

Market integration

Environment

Criteria

Attributes

Costs

Investment (CapEx) and operation cost (OpEx)

Financial effort. Cash flow

Environment

Environmental impact

RES integration

Market integration

Hours of market splitting

Exogenous factors

Social acceptance

Geopolitical risk
Which is the fastest animal of the nature in running, flying and swimming simultaneously?

- The fastest runner?

   *Cheetah* is the fastest running animal in the world

- The fastest flying?

   *Peregrine falcon* is the fastest bird in the world

- The fastest swimmer?

   *Sailfish* is the fastest fish in the world
Which is the fastest animal of the nature in all the three attributes simultaneously? And the winner is ... the DUCK

• Is able to run although less than the cheetah

• Is able to fly although less than the peregrine falcon

• Is able to swim although less than the sailfish
Weighted-Sum Method of MCDM

- Combines several quantifiable criteria in a single one by monetizing the criteria

\[
\min \sum_{i} \lambda_{i} z_{i}(x)
\]

- \(\lambda_{i}\) the weight of each criterion and \(z_{i}\) the value of the criterion

- Reliability: not served energy [MWh] monetized by multiplying by the cost of the energy not served [€/MWh]

- RES integration: RES curtailment/spillage [MWh] monetized by multiplying by the penalty associated to RES curtailment/spillage [€/MWh]

- Environmental impact: length of the line [km] multiplied by the restoration measures to be taken [€/km]

- No quantifiable criteria usually analyzed as a post-process for the best decisions under the previous method
Time scope

▪ Decision dynamics

▪ Static (myopic or short-sighted)
  • Determine optimal investment decisions for a particular horizon (year 2030) without representing how to achieve this optimal solution from now on
  • Can be useful as a “ideal” reference for very long time horizons

▪ Sequential static (forward vs. backwards planning)

▪ Dynamic
  • Determine optimal investment decisions since nowadays up to a particular horizon
  • More cumbersome to solve
Constraints

• Satisfy the demand
• Security of supply
  – Not served demand below a threshold
• RES integration
  – RES curtailment/spillage below a threshold
• Limit on the available budget
Definition

- Determine **which lines/transformers/substations and when to build** “optimizing”
  - Total investment and operation costs / Transmission regulatory framework
  - Economic and financial requirements
  - Unreliability (energy not served) cost
  - Environmental impact (land use, visual impact, EMF)

considering

- Dynamic long-term scope (10 – 20 years)
- Load forecast
- Existing and future generation location (RES, shale gas plants, retirement of coal power plants)
- Existing and committed network
- Network candidates (location and type proposed by the planner) and their investment costs
- Operation constraints / Electricity market
- Reliability criteria
- Financial/economic resources
- Political and administrative constraints (cause of many delays)
- Geographical/environmental constraints
- Energy policy targets
Results

• **Investment**
  – Which transmission corridors to build
  – What lines to reinforce
  – When

• **Operation**
  – Unit output and energy
  – CO2 emissions
  – RES integration/curtailment
  – Network flows
  – Energy exchanged among countries, % of congestion of interconnections
  – Reliability measures

• **Economic**
  – Investment and operation costs
  – Market impact
  – Sensitivity measures (dual variables)
Flexibility (modular development)

- Expansion plans are computed for each scenario
  - Determine flexible reinforcements that can be adapted over time to changes in a given non-random scenario (i.e., are common to many scenarios)
- Expansion plans that adapt to multiple scenarios as they develop (decision tree)
- **Long-term non-random uncertainty:**
  a. Installation of RES in the North & Baltic Seas
  b. Installation of CSP in MENA countries
  - A flexible solution will be based on installing firstly sections of the lines that will be needed under both previous scenarios)
Robustness

- Performs satisfactory under many possible non-random scenarios
- Appear in many expansion strategies
- Minimization of maximum regret
- **Protection against the worst scenario, which can be catastrophic**
- Two scenarios of energy demand growth:
  - a. Business as usual
  - b. Energy efficiency programs
    - A robust solution will be optimal (at least not catastrophic) for both scenarios
Transmission Expansion Planning. Centralized vs. Liberalized

Centralized (traditional, perfect competition) planning
• Minimize investment (CapEx) and operation costs (OpEx) to supply the demand subject to a certain reliability criterion, environmental and operation constraints

Liberalized markets
• Arrangements for transmission expansion planning
  • TSO is responsible of making the plan
  • Mixed planning carried out under collaboration of market agents and regulatory body
  • Planning carried out freely by market agents
  • Plan made by state agency but development and operation made privately
• Maximize all market agents (producers and consumers) aggregated net profits (taking into account network charges)
Transmission Expansion Planning. Solving Techniques

Optimization
- Metaheuristics
- Stochastic programming and decomposition methods

Simulation
- Monte Carlo simulation + variance reduction techniques
- Analytical methods

Other
- Game theory (cooperative decisions)
Transmission expansion planning model

Traditional TEP

**Minimize:**
Investment Cost + Operational Costs

**s.t.**
- Power balance for each node
- Network model (transport, AC/DC)
- Power limits on lines
- Security constraints (contingencies)
- Budget constraints
- Pre-existence constraints
  - 
  - 

Penalization Costs

Expected Costs or Minimax approaches

New approaches:

Additional Constraints

- TEP under uncertainty:
  - Stochastic programming
  - Robust optimization

Market Issues and Gaming Theory

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Other uses of transmission planning models

• Remuneration based on marginal contribution of the line to the system (congestion rent)
  – Difference of locational marginal prices (LMP) times the power flow

• Management of transmission capacity markets
After getting several optimal TEP plans...

- Check that transmission plan can be operated without voltage, stability and short-circuit concerns
1. Transmission Expansion Planning
2. Simple TEP models
3. Modeling issues
4. Prototype TEP. Mathematical formulation
5. Prototype TEP. Computer implementation

Prototype TEP. Mathematical formulation
Mathematical formulation

• **Objective function**
  – Minimize the total investment and expected operation costs

• **Investment variables**
  – *Investment decisions (what lines to build). Binary by nature*

• **Operation variables for each year**
  – Commitment, startup and shutdown of thermal units
  – Thermal, storage hydro and pumped storage hydro output
  – Flows through the lines

• **Investment constraints**
  – Operating capacity lower than installed capacity

• **Operation constraints for each year**
  – **Inter-period**
    • Storage hydro and pumped storage hydro scheduling
  – **Intra-period**
    • Load and reserve balance
    • Detailed hydro basin modeling
    • Thermal, hydro and pumped-storage operation constraints
Indices

- Time scope
  - years
- Period
  - 1 month
- Subperiod
  - weekdays and weekends
- Load level
  - peak, shoulder and off-peak
- Node

<table>
<thead>
<tr>
<th>Year</th>
<th>Node</th>
</tr>
</thead>
<tbody>
<tr>
<td>y</td>
<td>d</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Period</th>
<th>Subperiod</th>
<th>Load level</th>
</tr>
</thead>
<tbody>
<tr>
<td>p</td>
<td>s</td>
<td>n</td>
</tr>
</tbody>
</table>
Demand (5 weekdays)

Chronological Load Curve

Load Duration Curve

Load Duration Curve in 3 Load Levels
Demand

- **Monthly demand with several load levels**
  - Peak, shoulder and off-peak for weekdays and weekends
- **All the weekdays of the same month are similar (same for weekends)**

```
<table>
<thead>
<tr>
<th>Demand for each node [MW]</th>
<th>Duration [h]</th>
</tr>
</thead>
<tbody>
<tr>
<td>$D_{psnd}$</td>
<td>$d_{psn}$</td>
</tr>
<tr>
<td>Cumm. yearly demand growth [p.u.]</td>
<td>$I_y$</td>
</tr>
</tbody>
</table>
```

![Bar chart showing monthly demand](chart.png)

- **WorkingDay.n01**
- **WorkingDay.n02**
- **WorkingDay.n03**
- **WeekEnd.n01**
- **WeekEnd.n02**
- **WeekEnd.n03**
Technical characteristics of thermal units ($t$)

- Maximum and minimum output
- Fuel cost
- Slope and intercept of the heat rate straight line
- Operation and maintenance (O&M) variable cost
  - No load cost = fuel cost x heat rate intercept
  - Variable cost = fuel cost x heat rate slope + O&M cost
- Cold startup and shutdown cost
- Equivalent forced outage rate (EFOR)

<table>
<thead>
<tr>
<th>Max and min output [MW]</th>
<th>$\bar{p}_t, p_t$</th>
</tr>
</thead>
<tbody>
<tr>
<td>No load cost [€ / h]</td>
<td>$f_t$</td>
</tr>
<tr>
<td>Variable cost [€ / MWh]</td>
<td>$v_t$</td>
</tr>
<tr>
<td>Startup, shutdown cost [€]</td>
<td>$s_u_t, s_d_t$</td>
</tr>
<tr>
<td>EFOR [p.u.]</td>
<td>$q_t$</td>
</tr>
</tbody>
</table>
Technical characteristics of hydro plants \( (h) \)

- Maximum and minimum output
- Production function (efficiency for conversion of water inflow to electric power)
- Efficiency of pumped storage hydro plants
  - Only this ratio of the energy consumed to pump the water is recovered by turbining this water

<table>
<thead>
<tr>
<th>Max and min output</th>
<th>[MW]</th>
<th>( \bar{P}_h, \underline{P}_h )</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production function</td>
<td>[kWh / m(^3)]</td>
<td>( c_h )</td>
</tr>
<tr>
<td>Efficiency</td>
<td>[p.u.]</td>
<td>( \eta_h )</td>
</tr>
</tbody>
</table>
Technical characteristics of hydro reservoirs ($r$)

- **Maximum and minimum reserve**
- **Initial reserve** for every year
  - Final reserve = initial reserve
- **Stochastic inflows independent** for every year

- **Assumption:** There is no connection in reservoir levels or inflows between consecutive years

\[
\begin{align*}
\text{Max and min reserve} & \quad [hm^3] \quad r_r^*, r_r^-
\\
\text{Initial and final reserve} & \quad [hm^3] \quad r'_r
\\
\text{Stochastic inflows} & \quad [m^3/s] \quad i_{pr}^\omega
\end{align*}
\]
Hydro topology

Only one spillage per reservoir can be considered

Hydro plant upstream of reservoir \( h \in up(r) \) \( hur(h,r) \) \((h1,r3)\)

Pumped hydro plant upstream of reservoir \( h \in up(r) \) \( hpr(h,r) \) \((h3,r2)\)

Reservoir upstream of hydro plant \( h \in dw(r) \) \( ruh(r,h) \) \((r2,h2)\)

Reservoir upstream of pumped hydro plant \( h \in dw(r) \) \( rph(r,h) \) \((r3,h3)\)

Reservoir upstream of reservoir \( r' \in up(r) \) \( rur(r,r) \) \((r1,r3)\)
Scenario tree. Ancestor and descendant

Tree structure
- Scenario \( \omega \)
- Period \( p \)
- Scenario tree \((p, \omega)\)

Tree relations
- \( \omega' \in a(\omega) \)
- \((p02, sc03) \in a[(p03, sc03)]\)

Tree data
- Scenario probability \([p.u.]\) \(p^\omega_p\)
- Stochastic inflows \([m^3/s]\) \(i^\omega_{pr}\)

Scenario 1
- \((p01, sc01)\)
- \((p02, sc01)\)
- \((p02, sc03)\)

Scenario 2
- \((p03, sc02)\)

Scenario 3
- \((p03, sc03)\)

Scenario 4
- \((p03, sc04)\)
Technical characteristics of network lines ($dd'$)

- Resistance
- Reactance
- Maximum flow

<table>
<thead>
<tr>
<th>Characteristic</th>
<th>Unit</th>
<th>Expression</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resistance</td>
<td>[p.u.]</td>
<td>$R_{dd'}$</td>
</tr>
<tr>
<td>Reactance</td>
<td>[p.u.]</td>
<td>$X_{dd'}$</td>
</tr>
<tr>
<td>Maximum flow</td>
<td>[MW]</td>
<td>$F_{dd'}$</td>
</tr>
</tbody>
</table>
Technical characteristics of network lines \((dd')\)

- Investment cost
- Fixed charge rate
  - Annual investment cost = Investment cost x Fixed charge rate

\[
\text{Annual investment cost} \ [€] = f_{dd'}
\]
Other system parameters

- Energy not served cost
- Operating power reserve not served
- Operating power reserve
- Base power

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Unit</th>
<th>Symbol</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy not served cost</td>
<td>€ / MWh</td>
<td>$v'$</td>
</tr>
<tr>
<td>Power not served cost</td>
<td>€ / MW</td>
<td>$v''</td>
</tr>
<tr>
<td>Operating reserve</td>
<td>MW</td>
<td>$O_{ps1}$</td>
</tr>
<tr>
<td>Base power</td>
<td>MW</td>
<td>$S_B$</td>
</tr>
</tbody>
</table>
Investment variables

• Cumulative installation decision of the transmission line in every year

Cumulative installation decision of a candidate line \( \{0,1\} IC_{ydd} \)
Operation variables for each year

- **Commitment, startup and shutdown** of thermal units
  \[
  \{0, 1\} \quad UC_{yst}^{\omega}, SU_{yst}^{\omega}, SD_{yst}^{\omega}
  \]

- **Production** of thermal and hydro units
  \[
  \text{Production of a thermal or hydro unit} \quad [MW] \quad P_{ytn}^{\omega}, P_{ytnh}^{\omega}
  \]

- **Consumption** of pumped storage hydro plants
  \[
  \text{Consumption of a hydro plant} \quad [MW] \quad C_{ytnh}^{\omega}
  \]

- **Reservoir levels**
  \[
  \text{Reservoir level} \quad [hm^3] \quad R_{ypr}^{\omega}
  \]

- **Energy not served for each node** and **power not served**
  \[
  \text{Energy and power not served} \quad [MW] \quad ENS_{ytn}^{\omega}, PNS_{ytn}^{\omega}
  \]
Operation variables for each year

- **Flow** for the network lines

  \[ \text{Flow } [\text{MW}] \quad F_{y \psi \omega n d d'}^{\omega} \]

- **Voltage angle** in any node

  \[ \text{Voltage angle } [\text{rad}] \quad \theta_{y \psi \omega n d}^{\omega} \]
Constraints: Operating power reserve

Committed output of thermal units
+ Maximum output of hydro plants
+ Power not served
≥ Demand
+ Operating reserve for peak load level, subperiod, period and scenario

\[
\sum_t \bar{p}_t^{UC}_{yst} + \sum_h \bar{p}_h + PNS^{\omega}_{yps} \geq (D_{ps1} + O_{ps1})I_y \quad \forall \omega y ps
\]
Constraints: Generation and load balance for each node

Generation of thermal units
+ Generation of storage hydro plants
– Consumption of pumped storage hydro plants
+ Energy not served
+ Flow from incoming lines
– Flow from outgoing lines
= Demand for each node, load level, subperiod, period, year and scenario

\[
\sum_{t \in d} P^\omega_{yptsnt} + \sum_{h \in d} P^\omega_{yptsnh} - \sum_{h \in d} C^\omega_{yptsnh} + ENS^\omega_{yptsnd} + \\
\sum_{d'} F^\omega_{yptsnd'd} - \sum_{d'} F^\omega_{yptsdd'} = D_{psnd} I_y \quad \forall \omega yptsnd
\]
Constraints: Commitment, startup and shutdown

- All the weekdays of the same month are similar (same for weekends)
- Commitment decision of a thermal unit
- Assumption: no startup between periods of consecutive years
Constraints: Commitment, startup and shutdown

- **Startup** of thermal units can only be made in the transition between consecutive weekend and weekdays

  Commitment of a thermal unit in a weekday
  - Commitment of a thermal unit in the weekend of previous period
  = Startup of a thermal unit in this weekday
  - Startup of a thermal unit in this weekday

  \[ UC^\omega_{y_pst} - UC^{\omega'}_{y_{p-1}+1t} = SU^\omega_{y_{pst}} - SD^\omega_{y_{pst}} \quad \forall \omega y_{pst} \quad \omega' \in a(\omega) \]

- **Shutdown** only in the opposite transition

  Commitment of a thermal unit in a weekend
  - Commitment of a thermal unit in the previous weekday
  = Startup of a thermal unit in this weekend
  - Shutdown of a thermal unit in this weekend

  \[ UC^\omega_{y_{ps+1}t} - UC^\omega_{y_{pst}} = SU^\omega_{y_{ps+1}t} - SD^\omega_{y_{ps+1}t} \quad \forall \omega y_{pst} \]
Constraints: Commitment and production

Production of a thermal unit
≥ Commitment of a thermal unit times the minimum output reduced by availability rate

Production of a thermal unit
≤ Commitment of a thermal unit times the maximum output reduced by availability rate

\[ UC^\omega_{ypst} p_t (1 - q_t) \leq P^{\omega}_{ysnt} \leq UC^\omega_{ypst} p_t (1 - q_t) \quad \forall \omega_{ysnt} \]

• If the thermal unit is committed \((UC^\sigma_{ypst} = 1)\) it can produce between its minimum and maximum output
• If the thermal unit is not committed \((UC^\sigma_{ypst} = 0)\) it can’t produce
Constraints: Water balance for each reservoir

Reservoir volume at the beginning of the period
– Reservoir volume at the end of the period
+ Natural hydro inflows
– Spills from this reservoir
+ Spills from upstream reservoirs
+ Turbined water from upstream storage hydro plants
– Turbined and pumped water from this reservoir
+ Pumped water from upstream pumped hydro plants = 0 for each reservoir, period, year and scenario

\[
R'_{ypr-1} - R_{ypr} + i_{ypr} - S_{ypr} + \sum_{r' \in \text{up}(r)} S_{ypr'} + \sum_{sn} d_{psn} P_{ypsnh} / c_h - \sum_{sn} d_{psn} P_{ypsnh} / c_h \\
+ \sum_{sn} d_{psn} C_{ypsnh} \eta_h / c_h - \sum_{sn} d_{psn} C_{ypsnh} \eta_h / c_h = 0 \quad \forall \omega ypr \quad \omega' \in a(\omega)
\]
Constraints: Operation limits

Reservoir volumes between limits for each hydro reservoir

\[ r_{ypr} \leq R_{ypr}^\omega \leq r_{r} \quad \forall \omega \ ypr \]
\[ R_{0r} = R_{ypr}^\omega = r'_{r} \quad \forall \omega \ yr \]

Operation power lower than installed capacity

\[ 0 \leq P_{ypsnt}^\omega \leq \bar{p}_t(1 - q_t) \quad \forall \omega \ ypsnt \]
\[ 0 \leq P_{ypsnt}^\omega, C_{ypsnt}^\omega \leq \bar{p}_h \quad \forall \omega \ ypsnt \]

Commitment, startup and shutdown for each unit

\[ UC_{ypsnt}^\omega, SU_{ypsnt}^\omega, SD_{ypsnt}^\omega \in \{0,1\} \quad \forall \omega \ ypsnt \]
Constraints: **DC linearized load flow and flow limits**

**Flow in existing lines as a function of the voltage angles of beginning and ending nodes**

\[
F_{\omega_{ypsnd dd'}}^\omega = \frac{\theta_{\omega_{ypsnd}} - \theta_{\omega_{ypsnd'}}}{X_{dd'}} S_B \quad \forall \omega_{ypsnd dd'}
\]

**Flow in candidate lines as a function of the voltage angles of beginning and ending nodes**

\[
F_{\omega_{ypsnd dd'}}^\omega \leq \frac{\theta_{\omega_{ypsnd}} - \theta_{\omega_{ypsnd'}}}{X_{dd'}} S_B + \overline{F}'_{dd'} (1 - IC_{ydd'}) \quad \forall \omega_{ypsnd dd'}
\]

\[
F_{\omega_{ypsnd dd'}}^\omega \geq \frac{\theta_{\omega_{ypsnd}} - \theta_{\omega_{ypsnd'}}}{X_{dd'}} S_B - \overline{F}'_{dd'} (1 - IC_{ydd'}) \quad \forall \omega_{ypsnd dd'}
\]
Constraints: Flow limits and voltage angle

Flow of existing lines below limit for every year

\[-\bar{F}_{dd'} \leq F_{\omega ypsndd'} \leq \bar{F}_{dd'} \quad \forall \omega ypsndd'
\]

Flow of candidate lines below limit for every year

\[-\bar{F}_{dd'} IC_{ydd'} \leq F_{\omega ypsndd'} \leq \bar{F}_{dd'} IC_{ydd'} \quad \forall \omega ypsndd\]

Reference angle

\[\theta_{\omega ypsnd^*} = 0 \quad \forall \omega ypsn\]
Constraints: Installation decision in consecutive years

Increasing cumulative installation decision in following years

\[ IC_{ydd'} \leq IC_{y'd'd'} \quad \forall yy'd'd', y' > y \]
Multiobjective function

- Minimize

  - Transmission investment costs
  \[
  \sum_y \sum_{dd'} f^t IC^y_{dd'}
  \]

  - Thermal unit expected variable (fuel, O&M, emission) costs
  \[
  \sum_{y\omega ys t} p^\omega s_{ut} SU^\omega_{yps t} + \sum_{y\omega ys t} p^\omega s_{dt} SD^\omega_{yps t} + \sum_{y\omega yps nt} p^\omega d_{p s n} f UC^\omega_{yps t} + \]

  \[
  \sum_{y\omega yps nt} p^\omega d_{p s n} v^\omega_{yps n t} P^\omega_{yps n t}
  \]

  - Expected penalties introduced in the objective function for energy not served and power non served
  \[
  \sum_{y\omega yps nd} p^\omega d_{p s n} v' ENS^\omega_{yps nd} + \sum_{y\omega yps} p^\omega v'' PNS^\omega_{yps}
  \]
Long (Short) Run Marginal Cost (LRMC-SRMC)

- **Dual variable** of generation and load balance in each node [€/MW]
  - Change in the objective function due to a marginal increment in the demand when binary variables (investment, commitment, startup and shutdown) are continuous (long) fixed (short)

\[
\sum_{t \in d} P_{ypsnt}^\omega + \sum_{h \in d} P_{yphnh}^\omega - \sum_{h \in d} C_{yphnh}^\omega + \text{ENS}_{yphnd}^\omega + \\
\sum_{d'} F_{yphnd'd}^\omega - \sum_{d'} F_{yphnd'd'}^\omega = D_{yphn'd}^{\omega} \quad \forall \omega_{yphnd}
\]

- **Short Run Marginal Cost** = dual variable / load level duration / scenario probability. Expressed in [€/MWh]

\[
LRMC_{yphnd}^\omega = \sigma_{yphnd}^\omega / d_{psn} / p_p^\omega \quad \forall \omega_{yphnd}
\]
1. Transmission Expansion Planning
2. Simple TEP models
3. Modeling issues
4. Prototype TEP. Mathematical formulation
5. Prototype TEP. Computer implementation
**StarNetLite_TEPM** Long Term Transmission Expansion Model
(https://www.iit.comillas.edu/aramos/StarNetLite_TEPM.zip)

• Files
  – Microsoft Excel interface for input and output data StarNetLite_TEPM.xlsm
  – GAMS file StarNetLite_TEPM.gms

• How to use it
  – **Save the Excel workbook if data have changed**
  – Run the model
  – The model creates
    • tmp_StarNetLite_TEPM.xlsx with the output data and
    • StarNetLite_TEPM.lst as the listing file of the GAMS execution
  – Load the results into the Excel interface
Menu

StarNet Lite Long Term Transmission Expansion Planning Model

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Andrés Ramos
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andres.ramos@comillas.edu

Run

Load results
Input Data. Indices

1. years
2. p01
3. p02
4. p12
5. Weekday
6. Weekend
7. n01
8. n03
9. sc01
10. sc03
11. Thermal units
12. Nuclear
13. DomesticCoal_Antarctica
14. BrownLignite
15. ImportedCoal_SubBituminous
16. ImportedCoal_Bituminous
17. RunOffRiver
18. StorageHydro1_Basin1
19. StorageHydro2_Basin1
20. StorageHydro3_Basin1
21. PumpedStorageHydro
**Input Data. Cost of energy or power not served. Demand growth. Base power**

![Excel Sheet](image)
Input Data. Demand, operating reserve and duration
Input Data. Thermal and hydro parameters

### Thermal Generation

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Nuclear</td>
<td>771.6</td>
<td>771.6</td>
<td>1.00</td>
<td>15</td>
<td>0</td>
<td>0.00</td>
<td>15.00</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>DomesticCoal, Anthracite</td>
<td>588.0</td>
<td>235.2</td>
<td>0.02</td>
<td>2400</td>
<td>50000</td>
<td>6</td>
<td>2000000</td>
<td>0</td>
<td>0.00</td>
</tr>
<tr>
<td>BrownLignite</td>
<td>203.1</td>
<td>81.2</td>
<td>0.02</td>
<td>2300</td>
<td>50000</td>
<td>6</td>
<td>2000000</td>
<td>0</td>
<td>0.00</td>
</tr>
<tr>
<td>ImportedCoal, SubBituminous</td>
<td>150.4</td>
<td>60.2</td>
<td>0.02</td>
<td>2300</td>
<td>50000</td>
<td>6</td>
<td>2000000</td>
<td>0</td>
<td>0.00</td>
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<tr>
<td>ImportedCoal, Bituminous</td>
<td>194.4</td>
<td>77.8</td>
<td>0.02</td>
<td>2200</td>
<td>50000</td>
<td>6</td>
<td>2000000</td>
<td>0</td>
<td>0.00</td>
</tr>
<tr>
<td>CGGT_1</td>
<td>500.0</td>
<td>100.0</td>
<td>0.03</td>
<td>800</td>
<td>30000</td>
<td>6</td>
<td>1000000</td>
<td>0</td>
<td>0.00</td>
</tr>
<tr>
<td>CGGT_2</td>
<td>500.0</td>
<td>100.0</td>
<td>0.03</td>
<td>900</td>
<td>30000</td>
<td>6</td>
<td>1000000</td>
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<td>0.00</td>
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<tr>
<td>CGGT_3</td>
<td>662.5</td>
<td>133.5</td>
<td>0.03</td>
<td>800</td>
<td>30000</td>
<td>4</td>
<td>1000000</td>
<td>0</td>
<td>0.00</td>
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<tr>
<td>CGGT_4</td>
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<td>400.0</td>
<td>0.03</td>
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<td>1000000</td>
<td>4</td>
<td>1000000</td>
<td>0</td>
<td>0.00</td>
</tr>
<tr>
<td>FuelOilGas</td>
<td>441.8</td>
<td>441.8</td>
<td>0.06</td>
<td>2000</td>
<td>3000000</td>
<td>3</td>
<td>1000000</td>
<td>0</td>
<td>160.71</td>
</tr>
</tbody>
</table>

### Hydro Generation

<table>
<thead>
<tr>
<th>Plant Type</th>
<th>MaxProd [MW]</th>
<th>MinProd [MW]</th>
<th>ProdFunct [kWh/m³]</th>
<th>Efficiency</th>
<th>MaxCons [MW]</th>
</tr>
</thead>
<tbody>
<tr>
<td>RunOfRiver</td>
<td>150.0</td>
<td></td>
<td>0.30</td>
<td></td>
<td></td>
</tr>
<tr>
<td>StorageHydro1_Basin1</td>
<td>200.0</td>
<td></td>
<td>0.30</td>
<td></td>
<td></td>
</tr>
<tr>
<td>StorageHydro2_Basin1</td>
<td>200.0</td>
<td></td>
<td>0.30</td>
<td></td>
<td></td>
</tr>
<tr>
<td>StorageHydro3_Basin1</td>
<td>200.0</td>
<td></td>
<td>0.30</td>
<td></td>
<td></td>
</tr>
<tr>
<td>PumpedStorageHydro</td>
<td>200.0</td>
<td></td>
<td>0.70</td>
<td></td>
<td>200.0</td>
</tr>
</tbody>
</table>
Scenario tree

Scenario 1
(p01, sc01) → (p02, sc01) → (p03, sc01) → (p05, sc01)

Scenario 2
(p01, sc01) → (p02, sc02) → (p03, sc02) → (p05, sc02)

Scenario 3
(p01, sc01) → (p02, sc03) → (p03, sc03) → (p04, sc03) → (p05, sc03) → (p06, sc03)
Input Data. Inflows
Input Data. Existing and candidate lines

**Existing transmission network**

<table>
<thead>
<tr>
<th>Node_1, Node_6</th>
<th>X</th>
<th>TTC</th>
<th>FixedCost</th>
<th>FxChargeRate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Node_2, Node_3</td>
<td>0.002</td>
<td>0.020</td>
<td>800.0</td>
<td></td>
</tr>
<tr>
<td>Node_2, Node_4</td>
<td>0.004</td>
<td>0.030</td>
<td>800.0</td>
<td></td>
</tr>
<tr>
<td>Node_3, Node_6</td>
<td>0.006</td>
<td>0.040</td>
<td>800.0</td>
<td></td>
</tr>
<tr>
<td>Node_3, Node_4</td>
<td>0.008</td>
<td>0.050</td>
<td>800.0</td>
<td></td>
</tr>
<tr>
<td>Node_3, Node_5</td>
<td>0.007</td>
<td>0.060</td>
<td>800.0</td>
<td></td>
</tr>
<tr>
<td>Node_4, Node_6</td>
<td>0.005</td>
<td>0.070</td>
<td>800.0</td>
<td></td>
</tr>
<tr>
<td>Node_4, Node_5</td>
<td>0.003</td>
<td>0.080</td>
<td>800.0</td>
<td></td>
</tr>
<tr>
<td>Node_4, Node_8</td>
<td>0.011</td>
<td>0.090</td>
<td>800.0</td>
<td></td>
</tr>
<tr>
<td>Node_5, Node_8</td>
<td>0.005</td>
<td>0.050</td>
<td>800.0</td>
<td></td>
</tr>
<tr>
<td>Node_7, Node_8</td>
<td>0.011</td>
<td>0.060</td>
<td>800.0</td>
<td></td>
</tr>
<tr>
<td>Node_6, Node_9</td>
<td>0.005</td>
<td>0.070</td>
<td>800.0</td>
<td></td>
</tr>
</tbody>
</table>

**New transmission network**

<table>
<thead>
<tr>
<th>Node_1, Node_4</th>
<th>X</th>
<th>TTC</th>
<th>FixedCost</th>
<th>FxChargeRate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Node_1, Node_6</td>
<td>0.006</td>
<td>0.030</td>
<td>800.0</td>
<td>0.075</td>
</tr>
</tbody>
</table>
$Title StarNet Lite Long Term Transmission Expansion Planning Model (TEPM)

$OnText

Developed by

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October 23, 2017

$OffText

$OnEmpty OnMulti OffListing

* options to skip or not the Excel input/output
* if you want to skip it put these values to 1
* in such a case input files have to be already in the directory created by any other means
* output file will be the tmp.gdx that can be exported to Excel manually

@ifthen.OptSkipExcelInput %gams.user2% == ""
$ setglobal OptSkipExcelInput 0
$else.OptSkipExcelInput
$ setglobal OptSkipExcelInput %gams.user2%
$endif.OptSkipExcelInput

@ifthen.OptSkipExcelOutput %gams.user3% == ""
$ setglobal OptSkipExcelOutput 0
$else.OptSkipExcelOutput
$ setglobal OptSkipExcelOutput %gams.user3%
$endif.OptSkipExcelOutput

* solve the optimization problems until relative optimality of 1%
option OptCR = 0.01, IterLim=1000000, ResLim=3600, MINLP=SBB
StarNetLite_TEPM (ii)

* definitions

sets

y             year
ly(y)         not last year
z (y)         year
p             period
p1(p)         first period
pn(p)         last period
s             subperiod
s1(s)         first subperiod
n             load level
n1(n)         first load level
sc            scenario
sca (sc )    scenario
cp (sc,p )   tree defined as scenario and period
scscp(sc,p,sc) ancestor sc2 of node (sc1,p)
scschr(sc,sc,p) descendant (sc2 p) of node sc1
scscr(sc,p,sc) representative sc2 of node (sc1,p)
spsn(sc,p,s,n) active load levels for each scenario
psn ( p,s,n)  active load levels

g             generating unit
t (g)         thermal unit
h (g)         hydro plant
r             reservoir
rs(r)         storage reservoir
ruh(r,g)      reservoir upstream of hydro plant
rph(r,g)      reservoir upstream of pumped hydro plant
hur(g,r)      hydro plant upstream of reservoir
hpr(g,r)      pumped hydro plant upstream of reservoir
run(r,r)      reservoir 1 upstream of reservoir 2

nd            node (bus)
la(nd,nd)     existing and candidate lines
lc(nd,nd)     candidate lines
le(nd,nd)     existing lines
gnd(g,nd)     location of a unit at a node

alias (sc,scc), (r,rr), (nd,n1,nf)
StarNetLite_TEPM (iii)

<table>
<thead>
<tr>
<th>Parameters</th>
<th>Description</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td><code>pDemand</code> (sc, p, s, n)</td>
<td>Hourly load by node</td>
<td>[GW]</td>
</tr>
<tr>
<td><code>pDemShare</code> (nd)</td>
<td>Demand share</td>
<td>[p.u.]</td>
</tr>
<tr>
<td><code>pOperReserve</code> (sc, p, s, n)</td>
<td>Hourly operating reserve</td>
<td>[GW]</td>
</tr>
<tr>
<td><code>pDuration</code> (p, s, n)</td>
<td>Duration</td>
<td>[h]</td>
</tr>
<tr>
<td><code>pCommitt</code> (y, sc, g, p, s)</td>
<td>Commitment of the unit</td>
<td>[GW]</td>
</tr>
<tr>
<td><code>pProduct</code> (y, sc, g, p, s, n)</td>
<td>Production of the unit</td>
<td>[MW]</td>
</tr>
<tr>
<td><code>pEnergy</code> (y, sc, g, p, s, n)</td>
<td>Energy of the unit</td>
<td>[MWh]</td>
</tr>
<tr>
<td><code>pLRMC</code> (y, sc, nd, p, s, n)</td>
<td>Long run marginal cost</td>
<td>[€ per MWh]</td>
</tr>
<tr>
<td><code>pReserve</code> (y, sc, r, p)</td>
<td>Reserve level</td>
<td>[hm³]</td>
</tr>
<tr>
<td><code>pWValue</code> (y, sc, r, p)</td>
<td>Water value</td>
<td>[M€ per hm³]</td>
</tr>
<tr>
<td><code>pFlow</code> (y, sc, nd, nd, p, s, n)</td>
<td>Flow</td>
<td>[MW]</td>
</tr>
<tr>
<td><code>pTheta</code> (y, sc, nd, p, s, n)</td>
<td>Voltage angle</td>
<td>[rad]</td>
</tr>
<tr>
<td><code>pInstalCapT</code> (nd, nd, y)</td>
<td>TEP investment decision</td>
<td>[0-1]</td>
</tr>
<tr>
<td><code>pDemIncr</code> (y)</td>
<td>Yearly demand increment</td>
<td>[p.u.]</td>
</tr>
<tr>
<td><code>pCumDemIncr</code> (y)</td>
<td>Cum yearly demand increment</td>
<td>[p.u.]</td>
</tr>
<tr>
<td><code>pOrder</code> (y)</td>
<td>Ordinal of the year</td>
<td></td>
</tr>
<tr>
<td><code>pEFOR</code> (g)</td>
<td>EFOR</td>
<td>[p.u.]</td>
</tr>
<tr>
<td><code>pMaxProd</code> (g)</td>
<td>Maximum output</td>
<td>[GW]</td>
</tr>
<tr>
<td><code>pMinProd</code> (g)</td>
<td>Minimum output</td>
<td>[GW]</td>
</tr>
<tr>
<td><code>pMaxCons</code> (g)</td>
<td>Maximum consumption</td>
<td>[GW]</td>
</tr>
<tr>
<td><code>pSlopeVarCost</code> (g)</td>
<td>Slope variable cost</td>
<td>[€ per GWh]</td>
</tr>
<tr>
<td><code>pIntVarCost</code> (g)</td>
<td>Intercept variable cost</td>
<td>[€ per km³]</td>
</tr>
<tr>
<td><code>pStartupCost</code> (g)</td>
<td>Startup cost</td>
<td>[€]</td>
</tr>
<tr>
<td><code>pProdFunct</code> (g)</td>
<td>Production function</td>
<td>[GWh per km³]</td>
</tr>
<tr>
<td><code>pEffic</code> (g)</td>
<td>Pumping efficiency</td>
<td>[p.u.]</td>
</tr>
<tr>
<td><code>pInflows</code> (r, sc, p)</td>
<td>Inflows</td>
<td>[km³]</td>
</tr>
<tr>
<td><code>pENSCost</code></td>
<td>Energy non-served cost</td>
<td>[M€ per GWh]</td>
</tr>
<tr>
<td><code>pPNSCost</code></td>
<td>Power non-served cost</td>
<td>[M€ per GW]</td>
</tr>
<tr>
<td><code>pProbSc</code> (sc, p)</td>
<td>Probability of a given period</td>
<td></td>
</tr>
<tr>
<td><code>pR</code> (nd, nd)</td>
<td>Line resistance</td>
<td>[p.u.]</td>
</tr>
<tr>
<td><code>pX</code> (nd, nd)</td>
<td>Line reactance</td>
<td>[p.u.]</td>
</tr>
<tr>
<td><code>pTTC</code> (nd, nd)</td>
<td>Total transfer capacity</td>
<td>[GW]</td>
</tr>
<tr>
<td><code>pFixedCost</code> (nd, nd)</td>
<td>Fixed cost</td>
<td>[€]</td>
</tr>
<tr>
<td><code>pSbase</code></td>
<td>Base power</td>
<td>[GW]</td>
</tr>
<tr>
<td><code>lag(p)</code></td>
<td>Backward counting of period</td>
<td></td>
</tr>
<tr>
<td><code>scaux</code></td>
<td>Scenario number</td>
<td></td>
</tr>
</tbody>
</table>
variables
   vTotalTCost  total system cost [M€]
   vTotalFCost  total system fixed cost [M€]
   vTotalVCost  total system variable cost [M€]

binary variables
   vCommitt  (y,sc,p,s, g)  commitment of the unit [0-1]
   vStartup  (y,sc,p,s, g)  startup of the unit [0-1]
   vShutdown (y,sc,p,s, g)  shutdown of the unit [0-1]
   vCumInstDc(y, nd,nd)  cumulative installation decision [0-1]

positive variables
   vProduct  (y,sc,p,s,n,g)  production of the unit [GW]
   vConsump  (y,sc,p,s,n,g)  consumption of the unit [GW]
   vLosses   (y,sc,p,s,n,nd)  losses in a node [GW]
   vENS      (y,sc,p,s,n,nd)  energy non served [GW]
   vPNS      (y,sc,p,s)  power non served [GW]
   vWTRReserve(y,sc,p, r)  water reserve at end of period [km3]
   vSpillage (y,sc,p, r)  spillage [km3]

variables
   vFlow     (y,sc,p,s,n,nd,nd)  flow [GW]
   vTheta    (y,sc,p,s,n,nd,nd)  voltage angle [rad]

equations
   eTotalTCost  total system cost [M€]
   eTotalFCost  total system fixed cost [M€]
   eTotalVCost  total system variable cost [M€]

   eOpReserve(y,sc,p,s,n)  operating reserve [GW]
   eBalance  (y,sc,p,s,n,nd)  load generation balance [GW]
   eInstlCapC(y, nd,nd)  consecutive installed capacity [GW]
   eInstlCap1(y,sc,p,s,n,nd,n)  max flow by installed capacity [GW]
   eInstlCap2(y,sc,p,s,n,nd,n)  max flow by installed capacity [GW]
   eFlowNetN1(y,sc,p,s,n,nd,nd)  flow for each candidate line [GW]
   eFlowNetN2(y,sc,p,s,n,nd,nd)  flow for each candidate line [GW]
   eFlowNetEx(y,sc,p,s,n,nd,nd)  flow for each existing line [GW]
   eLosses   (y,sc,p,s,n,nd)  losses in a node [GW]
   eMaxOutput(y,sc,p,s,n,g)  max output of a committed unit [GW]
   eMINOutput(y,sc,p,s,n,g)  min output of a committed unit [GW]
   eProdctPer(y,sc,p,s,n,g)  unit production in same period [GW]
   eStartUpPer(y,sc,p,s, g)  unit startup in same period [km3]
   eStartUpNxt(y,sc,p,s, g)  unit startup in next period [km3] ;
StarNetLite_TEPM (v)

* mathematical formulation

eTotalCost .. vTotalCost =e= sum(y,lc, pFixedCost(lc)*vCumInstDc(y,lc) ) ;
eTotalFCost .. vTotalFCost =e= sum(y,scp(sc,p,sc,p,s,n), pProbSc(sc,p)*Duration(p,s,n)*PNSCost * vENS(y,sc,p,s,n) ) + sum(y,scp(sc,p,s,t), pProbSc(sc,p)*StartupCost(t) * vStartup(y,sc,p,s,t) ) + sum(y,scp(sc,p,s,n), t), pProbSc(sc,p)*Duration(p,s,n) * vPNS(y,sc,p,s,n,t) ) ;
eTotalVCost .. vTotalVCost =e= sum(y,scp(sc,p,s,n),t), pProbSc(sc,p)*Duration(p,s,n) * pSlopeVarCost(t)*vProduct(y,sc,p,s,n,t) ) ;

eOpReserve(y,scp(sc,p,s,n),n1(n)) .. pOperReserve(sc,p,s,n) =g= sum[t, MaxProd(t)*vCommitt(y,sc,p,s,n, t) ] + sum[h, MaxProd(h) + PNS(sc,p,sc,p,s,n) ] + vPNS(sc,p,sc,p,s,n) ;
eBalance(y,scp(sc,p,s,n), nd) .. sum[gnd(g,nd), vProduct(y,sc,p,s,n,g)] - sum[gnd(h,nd), vConsume(y,sc,p,s,n,h)] + ENS(y,sc,p,s,n,nd) =e= RemShare(nd) ;
eInstlCapC(y,y+1,lc) .. vCumInstDc(y,lc) =l= vCumInstDc(y+1,lc) ;
eInstlCap1(y,scp(sc,p,s,n),ni, nf) .. vFlow(y,sc,p,s,n,ni, nf) / pTTC(ni,nf) =g= [vTheta(y,sc,p,s,n,ni) - vTheta(y,sc,p,s,n,nf)] * pSbase / pX(ni,nf) / 1e3 * pTTC(ni,nf) - 1 + vCumInstDc(y,ni,nf) ;

eFlowNetN2(y,scp(sc,p,s,n),ni, nf) .. vFlow(y,sc,p,s,n,ni, nf) / 1e3 * pTTC(ni,nf) =l= [vTheta(y,sc,p,s,n,ni) - vTheta(y,sc,p,s,n,nf)] * pSbase / pX(ni,nf) / 1e3 * pTTC(ni,nf) + 1 - vCumInstDc(y,ni,nf) ;
eLosses(y,scp(sc,p,s,n),nd) .. vLosses(y,sc,p,s,n,nd) =e= pSbase * sum[la(nd,nd), (1-cos(vTheta(y,sc,p,s,n,nd) - vTheta(y,sc,p,s,n,nd)))] * pR(la)/[sqr(pR(la))+sqr(pX(la))] ;

eMaxOutput(y,scp(sc,p,s,n),t) .. pMaxProd(t) =g= vProduct(y,sc,p,s,n,t) / pMaxProd(t) =g= vCommitt(y,sc,p,s,n,t) ;
The model mTEPM / all - eLosses / ;
  mTEPM.SolPrint = 1 ; mTEPM.HoldFixed = 1 ; mTEPM.TryLinear = 1 ;

model mTEPM / all - eLosses / ;
mTEPM.SolPrint = 1 ; mTEPM.HoldFixed = 1 ; mTEPM.TryLinear = 1 ;

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StarNetLite_TEPM (vi)

* read input data from Excel and include into the model

```gams
file TMP / tmp_gams.user1%.txt /;
$echo > tmp_gams.user1%.txt
r1=    indices
o1=tmp_indices.txt
r2=    param
o2=tmp_param.txt
r3=    demand
o3=tmp_demand.txt
r4=    opress
o4=tmp_opress.txt
r5=    duration
o5=tmp_duration.txt
r6=    thermalgen
o6=tmp_thermalgen.txt
r7=    hydrogen
o7=tmp_hydrogen.txt
r8=    reservoir
o8=tmp_reservoir.txt
r9=    inflows
o9=tmp_inflows.txt
r10=  tree
o10=tmp_tree.txt
r11=  network
o11=tmp_network.txt
$offecho
* Mac OS X and Linux users must comment the following call and copy and paste the named ranges of the Excel interface into the txt files
$ifthen.OptSkipExcelInput '%OptSkipExcelInput%' == '0'
call xls2gms mi="%gams.user1%.xlsm" @"tmp_%gams.user1%.txt"
$else.OptSkipExcelInput
  log Excel input skipped
$endif.OptSkipExcelInput
sets
$include tmp_indices.txt;
  i
include tmp_param.txt

table pDemand(sc,p,s,n)
$include tmp_demand.txt

table pOperReserve(sc,p,s,n)
$include tmp_oprres.txt

table pDuration(p,s,n)
$include tmp_duration.txt

table pThermalGen(g,*)
$include tmp_thermalgen.txt

table pHydroGen(g,*)
$include tmp_hydrogen.txt

table pReservoir(r,*)
$include tmp_reservoir.txt

table pInflows(r,sc,p)
$include tmp_inflows.txt

table pScnTree(sc,*)
$include tmp_tree.txt

table pNetwork(nd,nd,*)
$include tmp_network.txt;
$offecho
* Mac OS X and Linux users must comment the following execute
execute 'del tmp"%gams.user1%.txt tmp_indices.txt tmp_param.txt tmp_demand.txt tmp_opress.txt tmp_duration.txt tmp_thermalgen.txt tmp_hydrogen.txt tmp_reservoir.txt tmp_inflows.txt tmp_tree.txt tmp_network.txt' ;
```
Transmission Expansion Planning

StarNetLite_TEPM (vii)

* determine the first and last period and the first subperiod

\[ p1(p) \quad [\text{ord}(p) = 1] = \text{yes} ; \]
\[ s1(s) \quad [\text{ord}(s) = 1] = \text{yes} ; \]
\[ n1(n) \quad [\text{ord}(n) = 1] = \text{yes} ; \]
\[ pn(p) \quad [\text{ord}(p) = \text{card}(p)] = \text{yes} ; \]
\[ psn(p,s,n) \quad [\text{pDuration}(p,s,n) = \text{yes}] ; \]
\[ \text{lag}(p) = \text{card}(p) - 2*\text{ord}(p) + 1 ; \]

* assignment of thermal units, storage hydro and pumped storage hydro plants

\[ t(g) \quad [\text{pThermalGen}(g,'\text{MaxProd}') \quad \text{and} \quad \text{pThermalGen}(g,'\text{FuelCost}')] = \text{yes} ; \]
\[ h(g) \quad [\text{pHydroGen}(g,'\text{MaxProd}')] = \text{yes} ; \]
\[ rs(r) \quad [\text{pReservoir}(r,'\text{MaxReserve}') > 0] = \text{yes} ; \]

* compute the cumulative yearly demand growth

\[ \text{ly}(y) \quad [\text{ord}(y) < \text{card}(y)] = \text{yes} ; \]
\[ z(y) = \text{ord}(y) ; \]
\[ \text{pOrder}(y) = \text{ord}(y) ; \]
\[ \text{pCumDemIncr}(y) = \text{prod}[z \quad [\text{pOrder}(z) \leq \text{ord}(y)], 1+\text{pDemIncr}(z)] ; \]
StarNetLite_TEPM (viii)

* scaling of parameters

\[
\begin{align*}
p_{\text{Demand}}(s,c,p,s,n) &= p_{\text{Demand}}(s,c,p,s,n) \times 10^{-3} ; \\
p_{\text{OperReserve}}(s,c,p,s,n) &= p_{\text{OperReserve}}(s,c,p,s,n) \times 10^{-3} ; \\
p_{\text{ENSCost}} &= p_{\text{ENSCost}} \times 10^{-3} ; \\
p_{\text{PNSCost}} &= p_{\text{PNSCost}} \times 10^{-3} ; \\
p_{\text{EFOR}}(t) &= p_{\text{ThermalGen}}(t, \text{'EFOR'}) ; \\
p_{\text{MaxProd}}(t) &= p_{\text{ThermalGen}}(t, \text{'MaxProd'}) \times 10^{-3} \times [1 - p_{\text{EFOR}}(t)] ; \\
p_{\text{MinProd}}(t) &= p_{\text{ThermalGen}}(t, \text{'MinProd'}) \times 10^{-3} \times [1 - p_{\text{EFOR}}(t)] ; \\
p_{\text{SlopeVarCost}}(t) &= p_{\text{ThermalGen}}(t, \text{'OMVarCost'}) \times 10^{-3} + p_{\text{ThermalGen}}(t, \text{'SlopeVarCost'}) \times 10^{-3} \times p_{\text{ThermalGen}}(t, \text{'FuelCost'}) ; \\
p_{\text{InterVarCost}}(t) &= p_{\text{ThermalGen}}(t, \text{'InterVarCost'}) \times 10^{-6} \times p_{\text{ThermalGen}}(t, \text{'FuelCost'}) ; \\
p_{\text{StartupCost}}(t) &= p_{\text{ThermalGen}}(t, \text{'StartupCost'}) \times 10^{-6} \times p_{\text{ThermalGen}}(t, \text{'FuelCost'}) ; \\
p_{\text{MaxProd}}(h) &= p_{\text{HydroGen}}(h, \text{'MaxProd'}) \times 10^{-3} ; \\
p_{\text{MinProd}}(h) &= p_{\text{HydroGen}}(h, \text{'MinProd'}) \times 10^{-3} ; \\
p_{\text{MaxCons}}(h) &= p_{\text{HydroGen}}(h, \text{'MaxCons'}) \times 10^{-3} ; \\
p_{\text{ProdFunct}}(h) &= p_{\text{HydroGen}}(h, \text{'ProdFunct'}) \times 10^{+3} ; \\
p_{\text{Eff}}(h) &= p_{\text{HydroGen}}(h, \text{'Efficiency'}) ; \\
p_{\text{MaxReserve}}(r) &= p_{\text{Reservoir}}(r, \text{'MaxReserve'}) \times 10^{-3} ; \\
p_{\text{MinReserve}}(r) &= p_{\text{Reservoir}}(r, \text{'MinReserve'}) \times 10^{-3} ; \\
p_{\text{IniReserve}}(r) &= p_{\text{Reservoir}}(r, \text{'IniReserve'}) \times 10^{-3} ; \\
p_{\text{Inflows}}(r,s,c) &= p_{\text{Inflows}}(r,s,c) \times 10^{-6} \times 3.6 \times \text{sum}((s,n), p_{\text{Duration}}(p,s,n)) ; \\
p_{\text{R}}(n_i,n_f) &= p_{\text{Network}}(n_i,n_f, \text{'R'}) ; \\
p_{\text{X}}(n_i,n_f) &= p_{\text{Network}}(n_i,n_f, \text{'X'}) ; \\
p_{\text{TTC}}(n_i,n_f) &= p_{\text{Network}}(n_i,n_f, \text{'TTC'}) \times 10^{-3} ; \\
p_{\text{FixedCost}}(n_i,n_f) &= p_{\text{Network}}(n_i,n_f, \text{'FixedCost'}) \times p_{\text{Network}}(n_i,n_f, \text{'FxChargeRate'}) ; \\
p_{\text{Sbase}} &= p_{\text{Sbase}} \times 10^{-3} ; \\
\end{align*}
\]

* assignment of all network lines (la) candidate lines (lc) and existing lines (le)

\[
\begin{align*}
\text{la}(n_i,n_f) \ \text{$p_{X}(n_i,n_f) = yes$} ; \\
\text{lc}(n_i,n_f) \ \text{$p_{\text{FixedCost}}(n_i,n_f) = yes$} ; \\
\text{le}(\text{la}(n_i,n_f)) \ \text{$[\text{not lc}(n_i,n_f)) = yes$} ; \\
\end{align*}
\]

* if the production function of a hydro plant is 0, it is changed to 1 and scaled to 1000
* if the efficiency of a hydro plant is 0, it is changed to 1

\[
\begin{align*}
p_{\text{ProdFunct}}(h) \ [p_{\text{ProdFunct}}(h) = 0] &= 10^3 ; \\
p_{\text{Eff}}(h) \ [p_{\text{Eff}}(h) = 0] &= 1 ; \\
\end{align*}
\]
StarNetLite_TEPM (ix)

* bounds on variables

\[
\begin{align*}
\text{vProduct.up} & \quad (y,sc,p,s,n,g) = p\text{MaxProd}(g) ; \\
\text{vConsume.up} & \quad (y,sc,p,s,n,g) = p\text{MaxCons}(g) ; \\
\text{vPNS.up} & \quad (y,sc,p,s) = \sum[n1(n), [p\text{Demand}(sc,p,s,n) + p\text{OperReserve}(sc,p,s,n)] * p\text{CumDemIncr}(y)] ; \\
\text{vENS.up} & \quad (y,sc,p,s) = p\text{Demand}(sc,p,s,n) * p\text{DemShare}(nd) * p\text{CumDemIncr}(y) ; \\
\text{vWtReserve.up} & \quad (y,sc,p,r) = p\text{MaxReserve}(r) ; \\
\text{vWtReserve.lo} & \quad (y,sc,p,r) = p\text{MinReserve}(r) ; \\
\text{vWtReserve.fx} & \quad (y,sc,p,r) = p\text{IniReserve}(r) ; \\
\text{vFlow.lo} & \quad (y,sc,p,s,n,la) = - p\text{TTC}(la) ; \\
\text{vFlow.up} & \quad (y,sc,p,s,n,la) = p\text{TTC}(la) ; \\
\text{vTheta.fx} & \quad (y,sc,p,s,n,nd)[\text{ord}(nd) = 1] = 0 ;
\end{align*}
\]

* voltage angle of the reference node is fixed to 0

\[
\text{vTheta.fx} (y,sc,p,s,n,nd) [\text{ord}(nd) = 1] = 0 ;
\]
StarNetLite_TEPM (x)

* define the nodes of the scenario tree and determine ancestor sc2 of node (sc1 p) and descendant (sc2 p) of node sc1

scp ( sc, p ) \{ ord(p) >= pScnTree(sc, 'FirstPeriod') \} = yes;
scp(scp(sc,p),scc) \{ ord(p) > pScnTree(sc, 'FirstPeriod') and ord(scc) = ord(sc) \} = yes;
scp(scp(sc,p),scc) \{ ord(p) = pScnTree(sc, 'FirstPeriod') and ord(scc) = pScnTree(sc, 'Ancestor') \} = yes;
sch(sc,sch(sc,p)) \{ scscp(scc,p,sc) \} = yes;
pP robSc(sc,pn(p)) = pScnTree(sc, 'Prob')/\sum [scc, pScnTree(sc, 'Prob')]

\textbf{loop} (p \{ not p1(p)\},
  pProbSc(scp(sc,p+lag(p))) = \sum [sch(sc,scc,p+(lag(p)+1)), pProbSc(scc,p+(lag(p)+1))]
)

* delete branches with probability 0 and define the active load levels

scp ( sc, p ) \{ pProbSc(sc,p) = 0 \} = no;
sch(sc,scc,p) \{ pProbSc(scc,p-1) = 0 \} = no;
sch(sc,scc,p) \{ pProbSc(sc,p) = 0 or pProbSc(scc,p-1) = 0 \} = yes $\textbf{scp}(scc,p,sc);
spsn (scp(sc,p),s,n) \{ psn (p,s,n) \} = yes;

* determine the representative sc2 of node (sc1 p) for non-existing scenarios in the tree

\textbf{loop} (sc \{ sum[p, pProbSc(sc,p)] \}
  scaux = ord(sc);
  \textbf{loop} (p,
    schcr(sc,p+lag(p),scc) \{ ord(scc) = scaux \} = yes;
    SCA(scc) \{ ord(scc) = scaux \} = yes;
    scaux = sum[schcr(scc,p+lag(p),scc), ord(scc)]
    SCA(scc) \{ \} = no;
  );
) ;

SCA(sc) \{ sum[p, pProbSc(sc,p)] \} = yes;
StarNetLite_TEPM (xi)

solve mTEPM using MINLP minimizing vTotalTCost;

* scaling of the results

\[ p_{\text{InstalCap}}(lc,y) = \text{vCumInstDc}(y,lc) + \varepsilon; \]

\[ p_{\text{Commit}}(y,scc,psn,rs,lc) = \sum \left[ \text{vCommitt}(y,scc,psn,rs,lc) \right] + \varepsilon; \]

\[ p_{\text{Product}}(y,scc,psn,lc) = \sum \left[ \text{vProduct}(y,scc,psn,lc) \right] \times 10^3 + \varepsilon; \]

\[ p_{\text{Energy}}(y,scc,psn,lc) = \sum \left[ \text{vProduct}(y,scc,psn,lc) \times \text{pDuration}(y,scc,psn,lc) \right] \times 10^3 + \varepsilon; \]

\[ p_{\text{Reserve}}(y,scc,psn,lc) = \sum \left[ \text{vWtReserve}(y,scc,psn,lc) \right] \times 10^3 + \varepsilon; \]

\[ p_{\text{WValue}}(y,scc,psn,lc) = \sum \left[ \text{vWtReserve}(y,scc,psn,lc) / \text{pDuration}(y,scc,psn,lc) \right] \times 10^3 + \varepsilon; \]

\[ p_{\text{Flow}}(y,scc,psn,lc) = \sum \left[ \text{vFlow}(y,scc,psn,lc) \right] \times 10^3 + \varepsilon; \]

\[ p_{\text{Theta}}(y,scc,psn,lc) = \sum \left[ \text{vAngle}(y,scc,psn,lc) \right] \times 10^3 + \varepsilon; \]

\[ p_{\text{LRMC}}(y,scc,psn,lc) = \sum \left[ \text{vWtReserve}(y,scc,psn,lc) / \text{pDuration}(y,scc,psn,lc) \right] \times 10^3 + \varepsilon; \]

* data output to xis file

put TMP putclose 'par=pProduct rdim=3 rng=Output!a1' / 'par=pEnergy rdim=3 rng=Energy!a1' / 'par=pReserve rdim=3 rng=WtrReserve!a1' / 'par=pWValue rdim=3 rng=WtrValue!a1' / 'par=pLRMC rdim=3 rng=LRMC!a1' / 'par=pCommit rdim=3 rng=UC!a1' / 'par=pInstalCapT rdim=2 rng=InstalCapT!a1' / 'par=pFlow rdim=4 rng=Flow!a1' / 'par=pTheta rdim=3 rng=Angle!a1' /

\[ \text{t}
\]
Output Data. Production for year 1
Output Data. Energy for year 1
Output Data. Reservoir level for year 1

Initial reservoir level (500 hm³)
Output Data. Water value for year 1
If TEP model is solved with binary investment decisions no marginal impact of those decisions is taken into account.
Task assignment

• At what threshold of transmission investment (fixed) cost does the potential new transmission line become economically viable (breakeven) in the sample model for installing the line in year 3?

• Assume that the transmission investment decisions have been already made, introduce the computation of congestion rents in GAMS and compare these congestion rents with the investment cost of a candidate transmission line.

• Based on this model think about how to implement mathematically the decision of opening lines (switching) in any period.

• Analyze the impact of the losses (with and without) in the expansion decisions.
Takeaways

- Main drivers to build transmission lines
- Some characteristics to be considered into this model
- Non-random and random uncertainties affecting the analysis
- Main criteria used to define the best alternatives
- Decision framed as a MCDM solved by weighted-sum method
- Where to use a transmission expansion planning model
- Input data and output results
- Mathematical techniques used to solve the model
- A prototype transmission expansion planning model
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