MITEI-IAP24
Computational modeling for clean, reliable, and affordable electricity
Massachusetts Institute of Technology (MIT)

Transmission Expansion Planning

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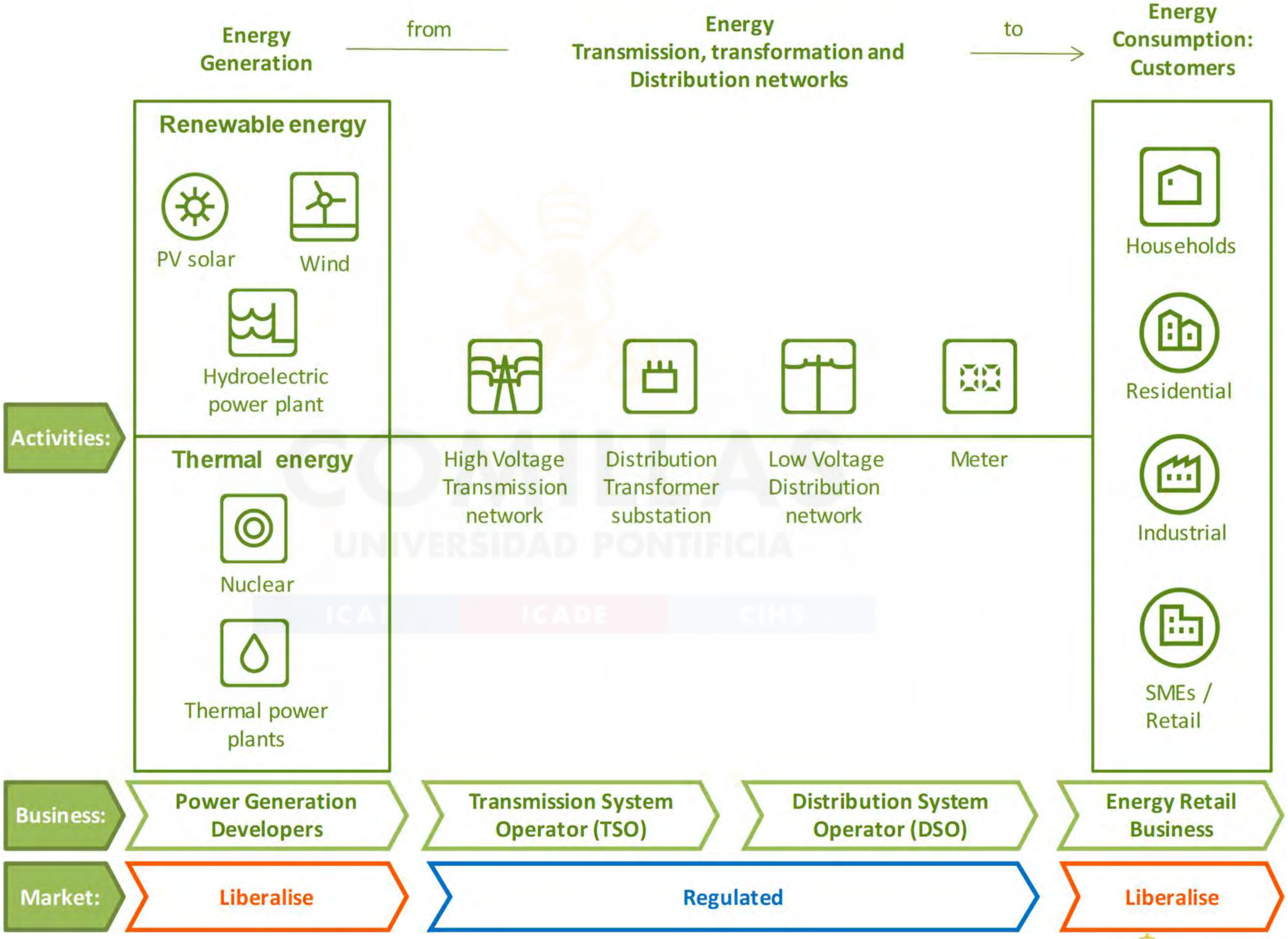
Motivation

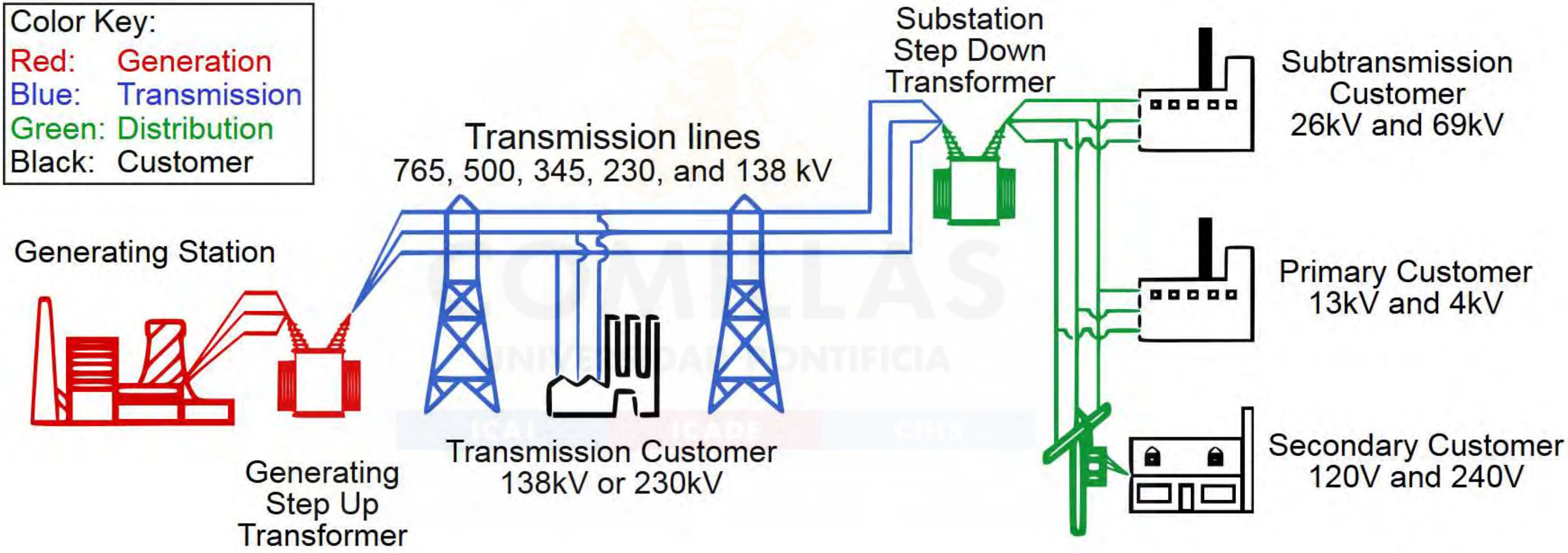
- To understand why the transmission plays a vital role in renewable integration
- To indicate what it is possible to state with a decision tool
  - Capabilities and limitations
- To become familiar with transmission network expansion modeling techniques
- To give the mathematical foundation

Electric System. Activities, businesses and markets



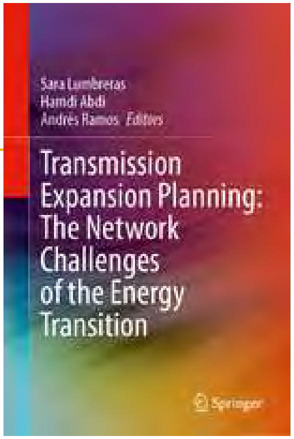
Source: Iberdrola

Electric System. Physical layout



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

References



Sara Lumbreras
Hamdi Abdi
Andrés Ramos *Editors*

Transmission Expansion Planning: The Network Challenges of the Energy Transition

Springer

- S. Lumbreras, H. Abdi, A. Ramos (eds.) *Transmission Expansion Planning: The Network Challenges of the Energy Transition* Springer, 2020 ISBN 9783030494278 10.1007/978-3-030-49428-5
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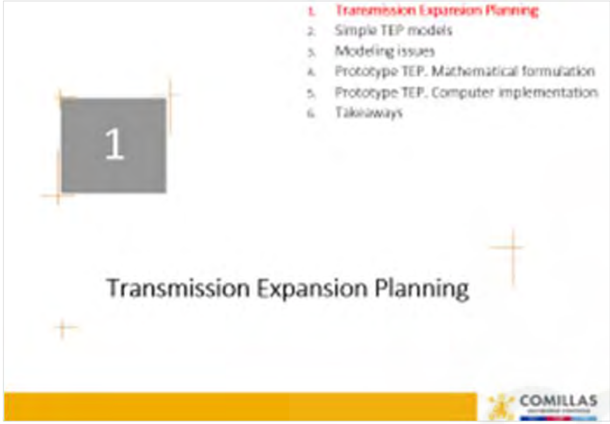
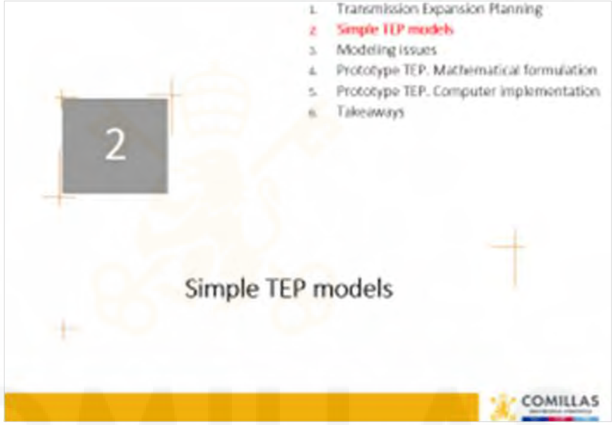
Content



1. Transmission Expansion Planning
2. Simple TEP models
3. Modeling issues
4. Prototype TEP. Mathematical formulation
5. Prototype TEP. Computer implementation
6. Takeaways

1

Transmission Expansion Planning



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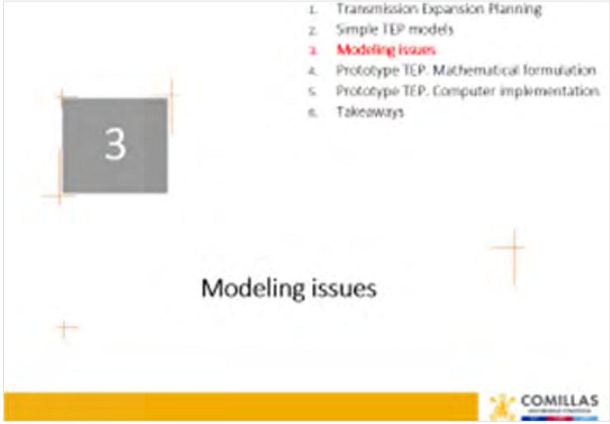
2

Simple TEP models



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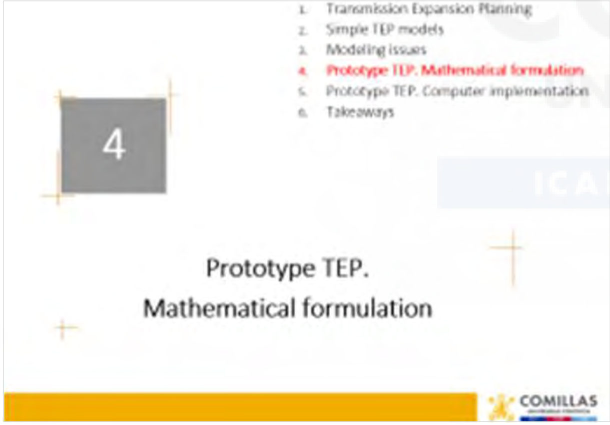
Modeling issues



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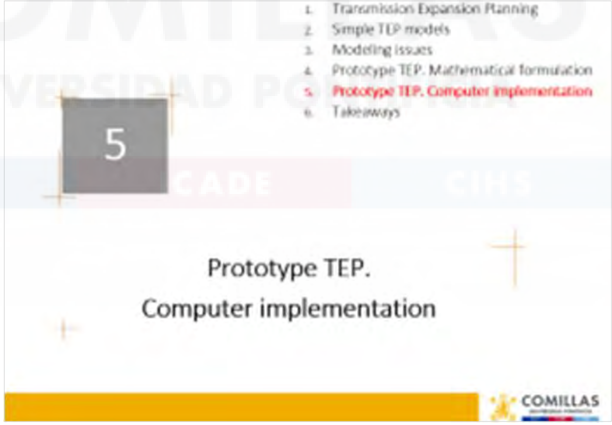
4

Prototype TEP.
Mathematical formulation



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5

Prototype TEP.
Computer implementation

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6. Takeaways

6

Takeaways

1. Transmission Expansion Planning
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5. Prototype TEP. Computer implementation
6. Takeaways

1

Transmission Expansion Planning

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

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

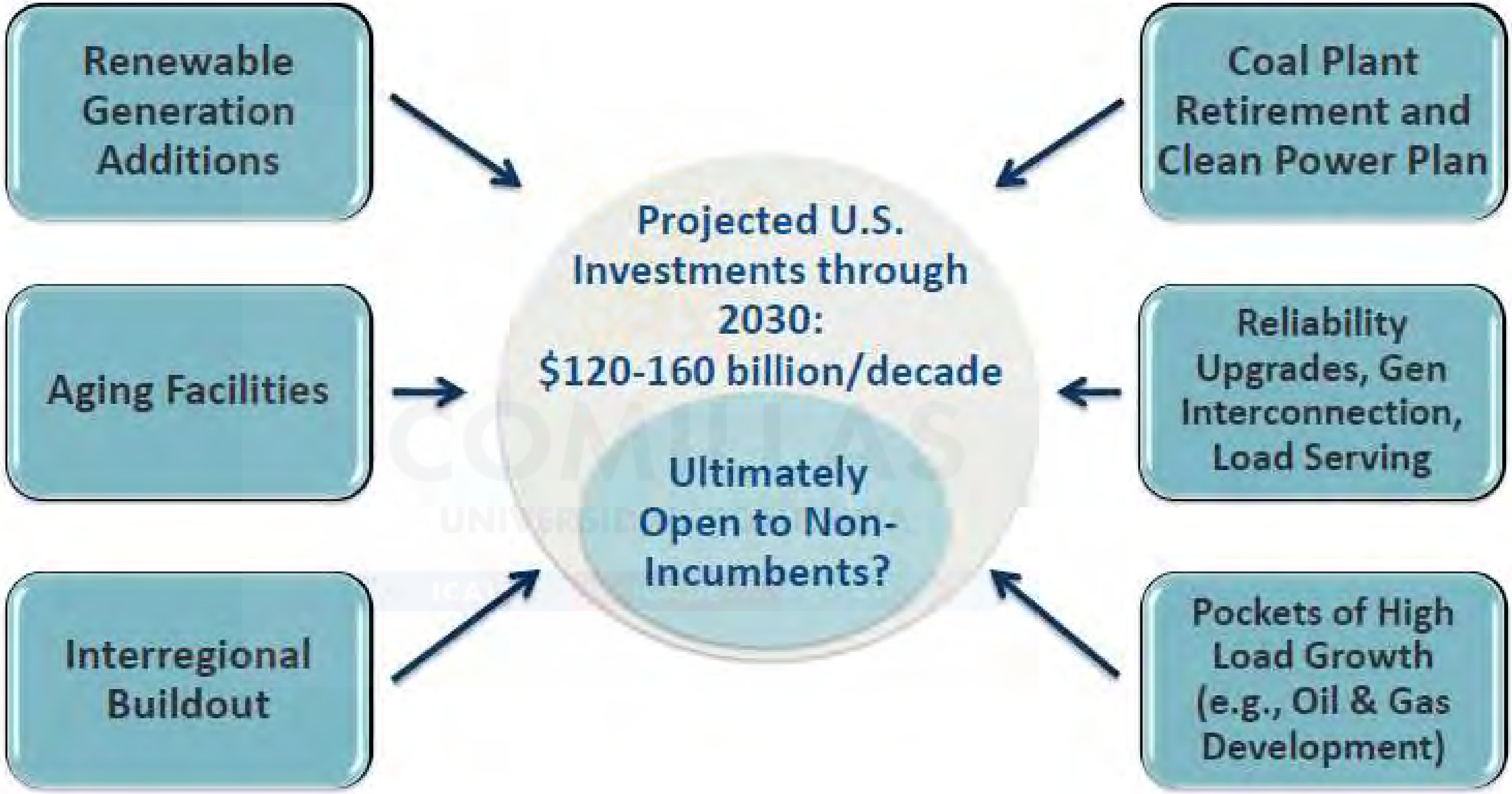
TenneT network planning - to guarantee system stability

https://youtu.be/P5Nol6dyJN4

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)
  - European Green Deal: 55% emission reductions by 2030 (Fit for 55)
    https://www.consilium.europa.eu/en/policies/green-deal/
  - National Energy and Climate Plans (NCEP)

USA Projected Transmission Investment Opportunities



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)

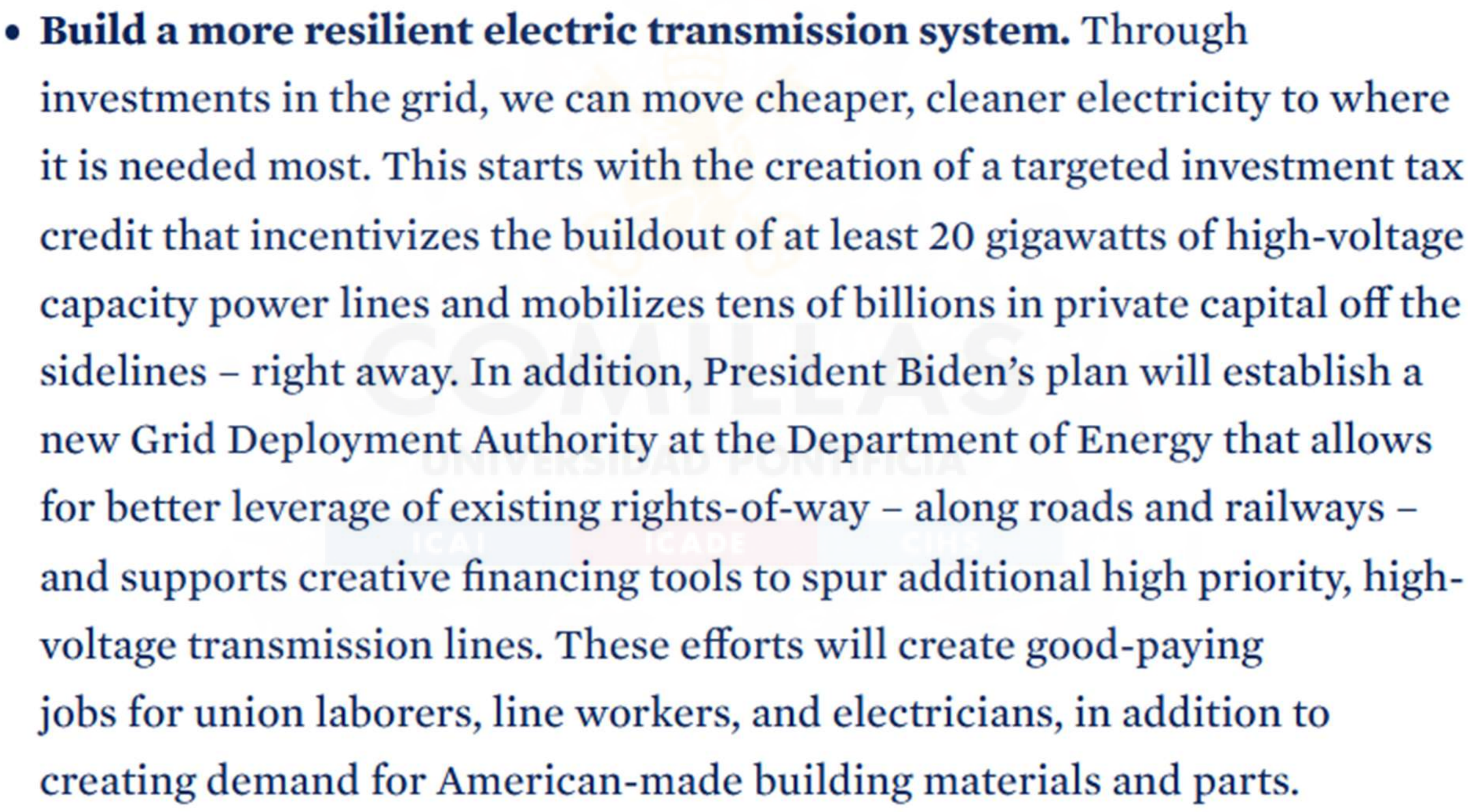
Projected U.S. Investments through 2030: $120-160 billion/decade

Ultimately Open to Non-Incumbents?

http://www.brattle.co.uk/industry/electric-power/82-transmission

The White House. FACT SHEET: The American Jobs Plan

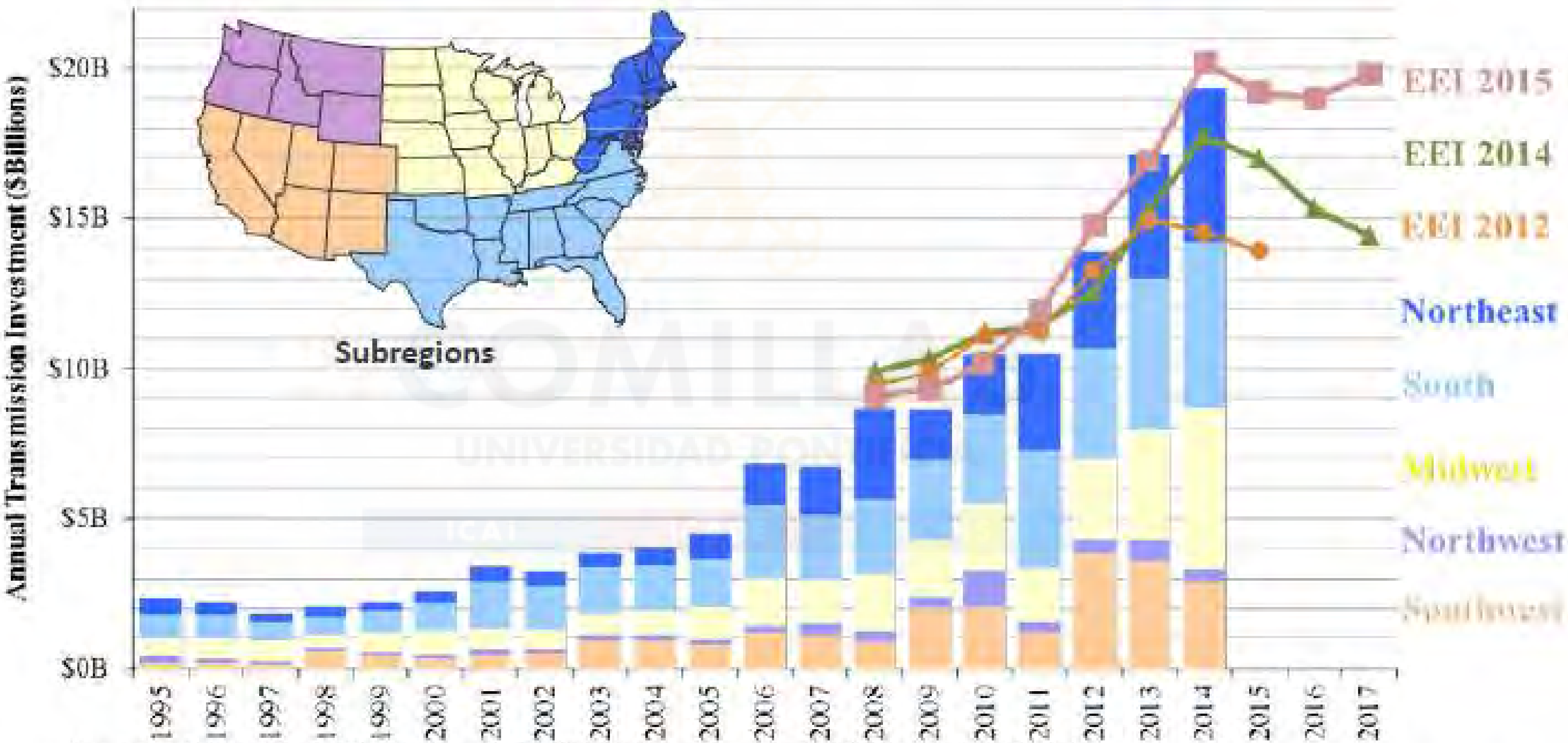
Reenergize America’s power infrastructure



- **Build a more resilient electric transmission system.** Through investments in the grid, we can move cheaper, cleaner electricity to where it is needed most. This starts with the creation of a targeted investment tax credit that incentivizes the buildout of at least 20 gigawatts of high-voltage capacity power lines and mobilizes tens of billions in private capital off the sidelines – right away. In addition, President Biden’s plan will establish a new Grid Deployment Authority at the Department of Energy that allows for better leverage of existing rights-of-way – along roads and railways – and supports creative financing tools to spur additional high priority, high-voltage transmission lines. These efforts will create good-paying jobs for union laborers, line workers, and electricians, in addition to creating demand for American-made building materials and parts.

USA Historical and Projected Transmission Investments

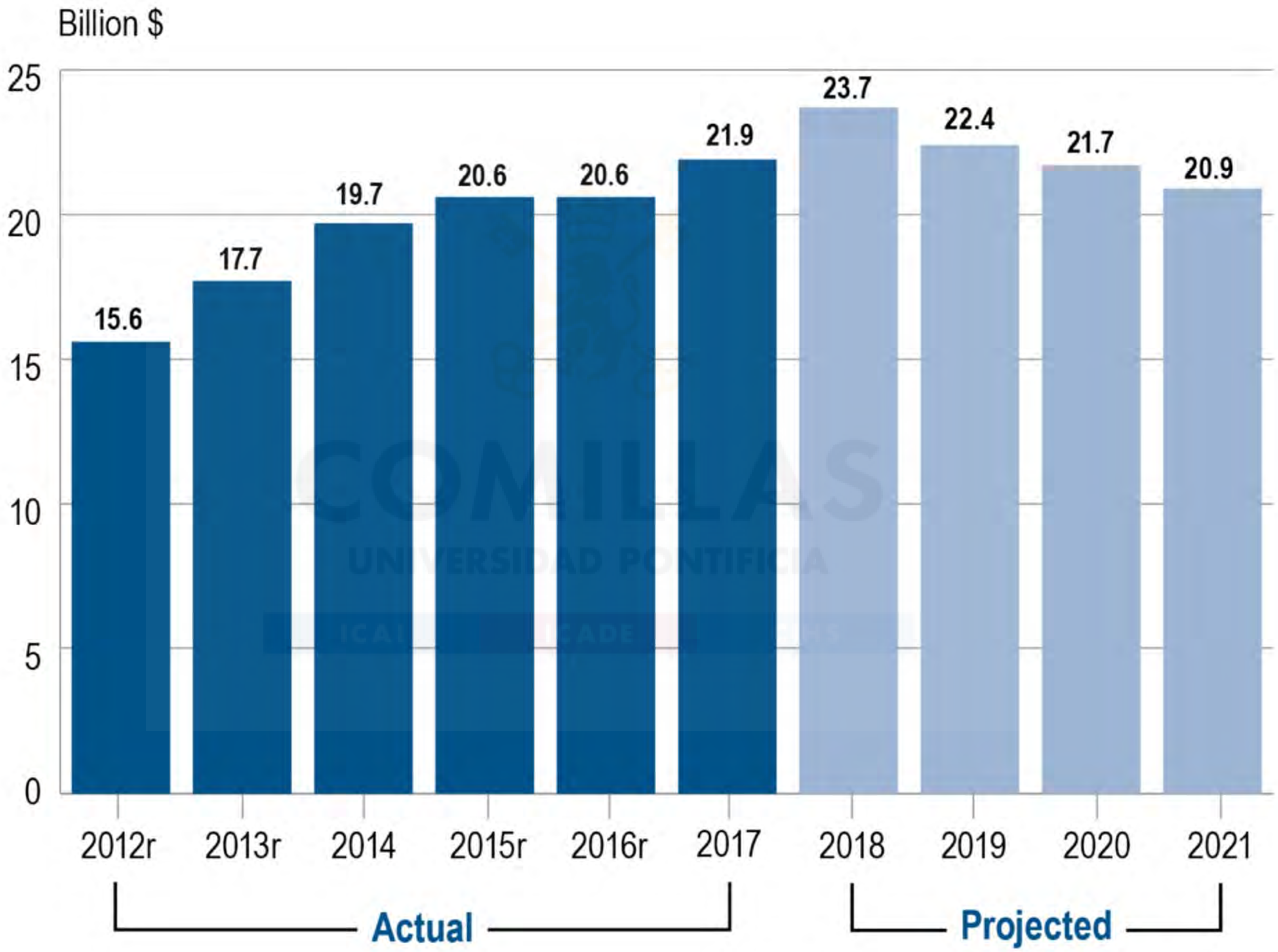
1995-2017 Annual Transmission Investment of Investor-Owned Utilities by FERC Subregion



Sources and Notes: The Brattle Group's analysis of FERC Form 1 data compiled in Ventyx's Velocity Suite.
Based on EIA data available through 2003, FERC-jurisdictional transmission owners estimated to account for 80% of transmission assets in the Eastern Interconnection, and 60% in WECC and ERCOT. Facilities >300kV estimated to account for 60-80% of shown investments.
EEI annual transmission expenditures updated June 2015 shown (2008-2017) based on prior year's actual investment through 2013 and planned investment thereafter.

http://www.brattle.co.uk/industry/electric-power/82-transmission

USA Historical and Projected Transmission Investments



New England Clean Energy Connect (NECEC)

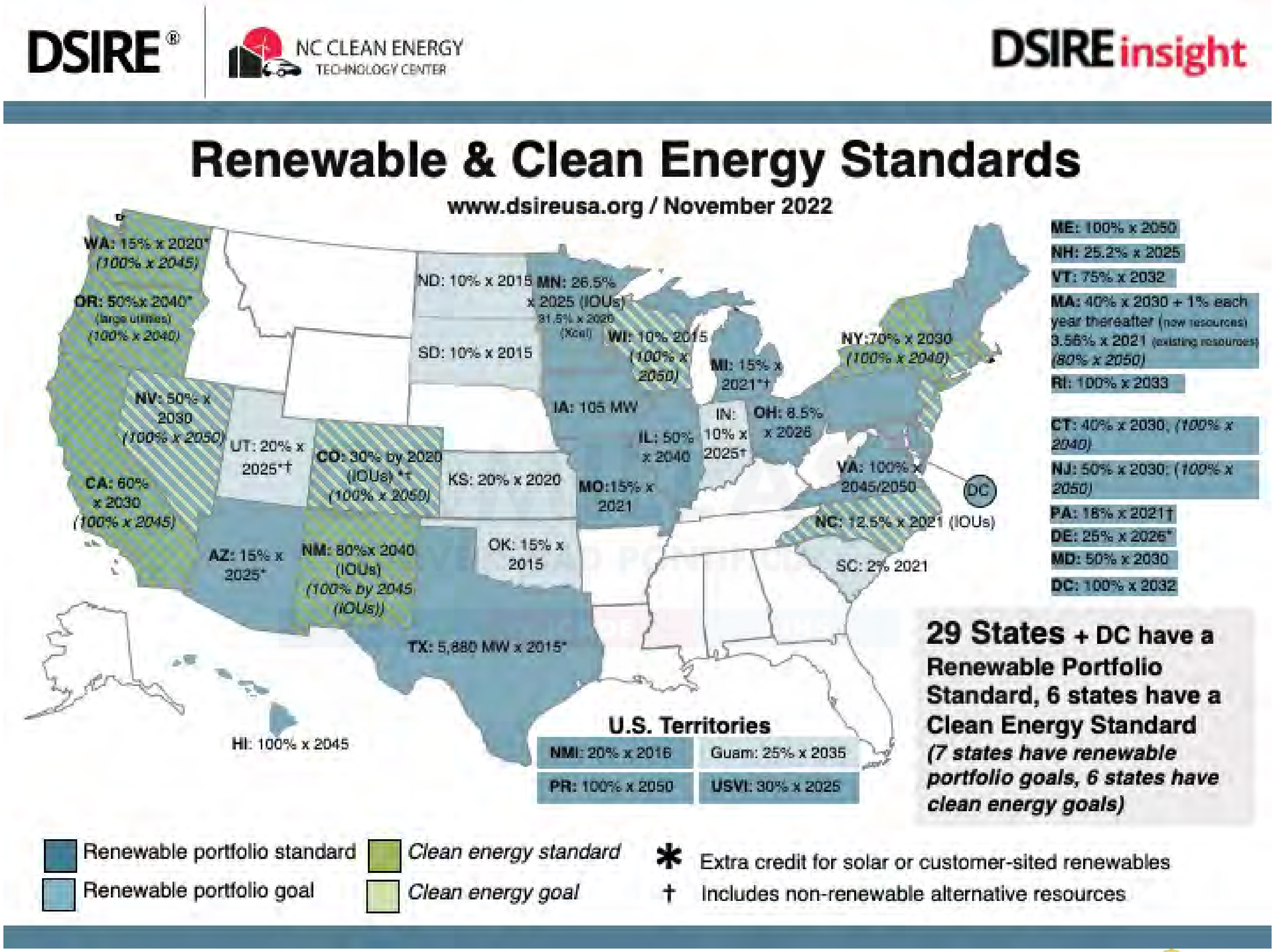
145 miles (233 km) of new HVDC line with 1200 MW at 345 kV, new DC/AC converter station, and multiple system upgrades

Started in January 2021

https://youtu.be/TEdr_DfzUyE

https://www.necleanenergyconnect.org/

USA Renewable Portfolio Standards (RPS)



Renewable & Clean Energy Standards

www.dsireusa.org / November 2022

U.S. Territories

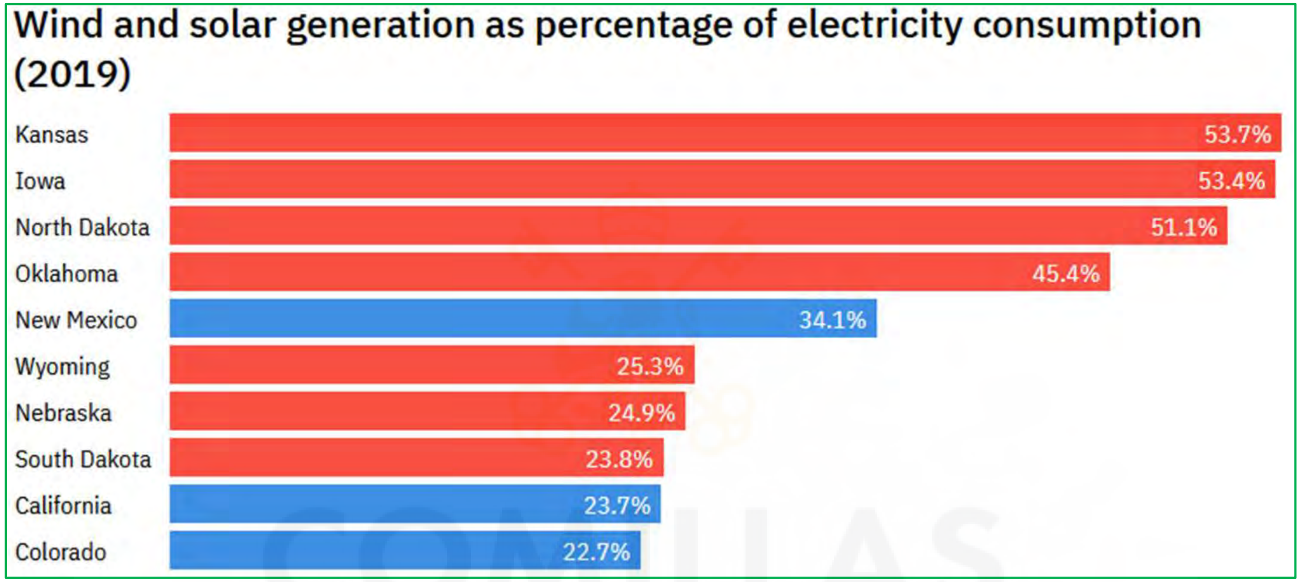
NMI: 20% x 2016	Guam: 25% x 2035
PR: 100% x 2050	**USVI:** 30% x 2025

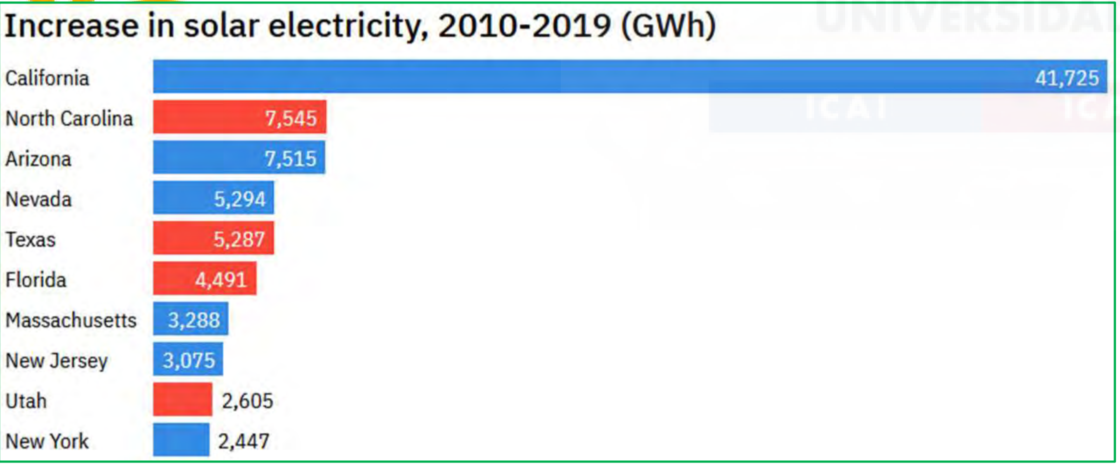
29 States + DC have a Renewable Portfolio Standard, 6 states have a Clean Energy Standard
(7 states have renewable portfolio goals, 6 states have clean energy goals)

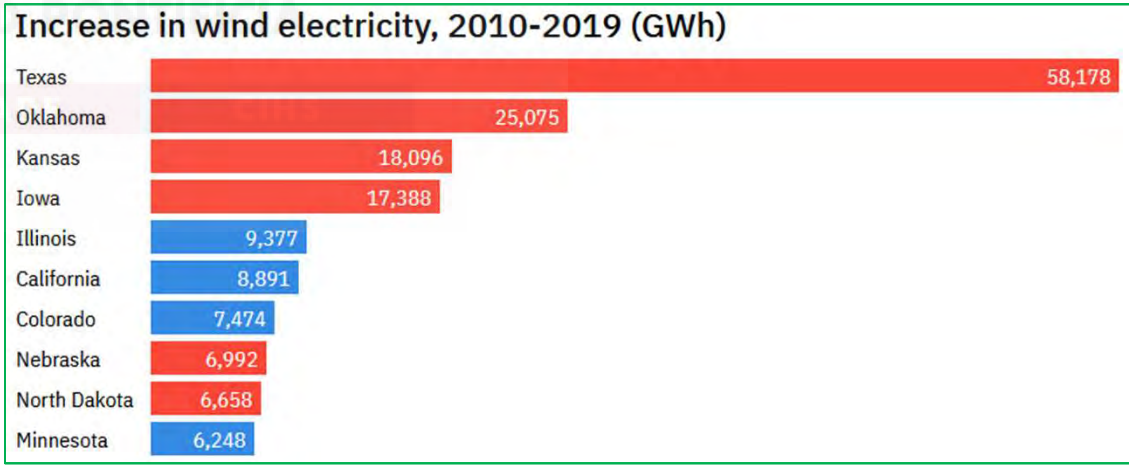
- ■ Renewable portfolio standard
- ■ Renewable portfolio goal
- ■ *Clean energy standard*
- ■ *Clean energy goal*
- * Extra credit for solar or customer-sited renewables
- † Includes non-renewable alternative resources

Source: www.dsireusa.org November 2022

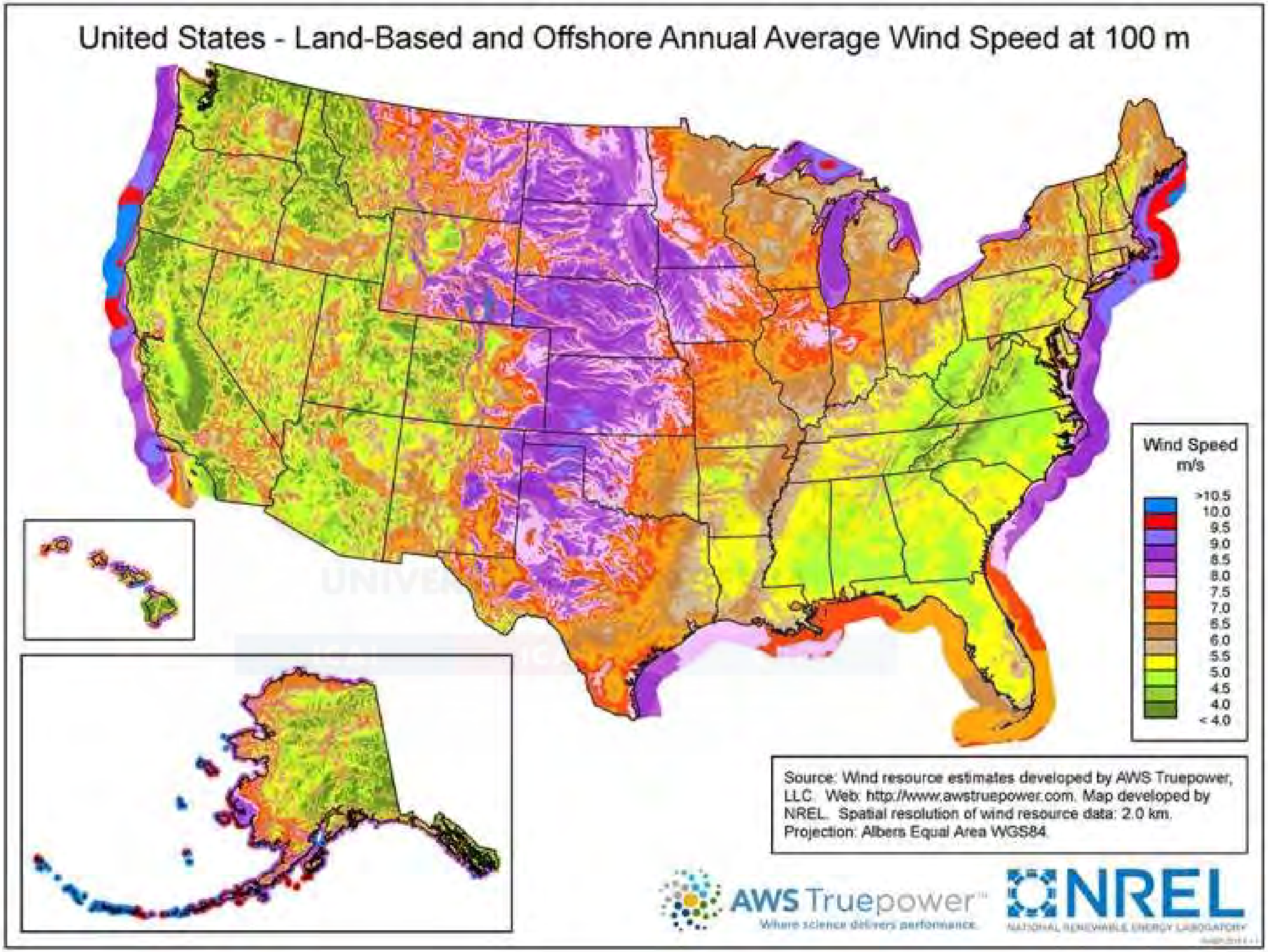
US red states among wind and/or solar leaders


Wind and solar generation as percentage of electricity consumption (2019)


Increase in solar electricity, 2010-2019 (GWh)


Increase in wind electricity, 2010-2019 (GWh)

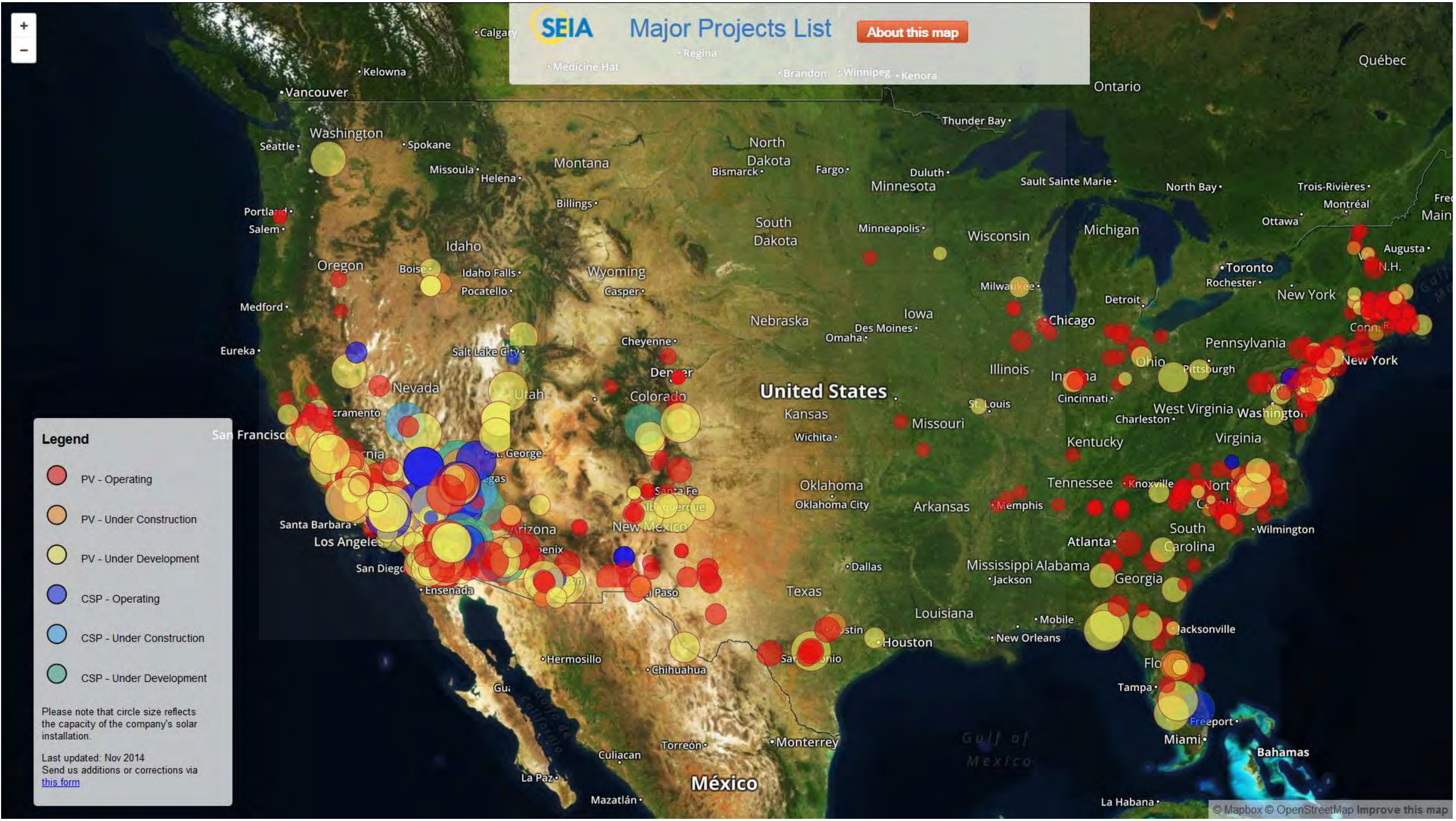
Land Based and Offshore Annual Average Wind Speed at 100 Meters



Source: Wind resource estimates developed by AWS Truepower, LLC. Web: http://www.awstruepower.com. Map developed by NREL. Spatial resolution of wind resource data: 2.0 km. Projection: Albers Equal Area WGS84.

https://energy.gov/eere/wind/downloads/united-states-land-based-and-offshore-annual-average-wind-speed-100-meters

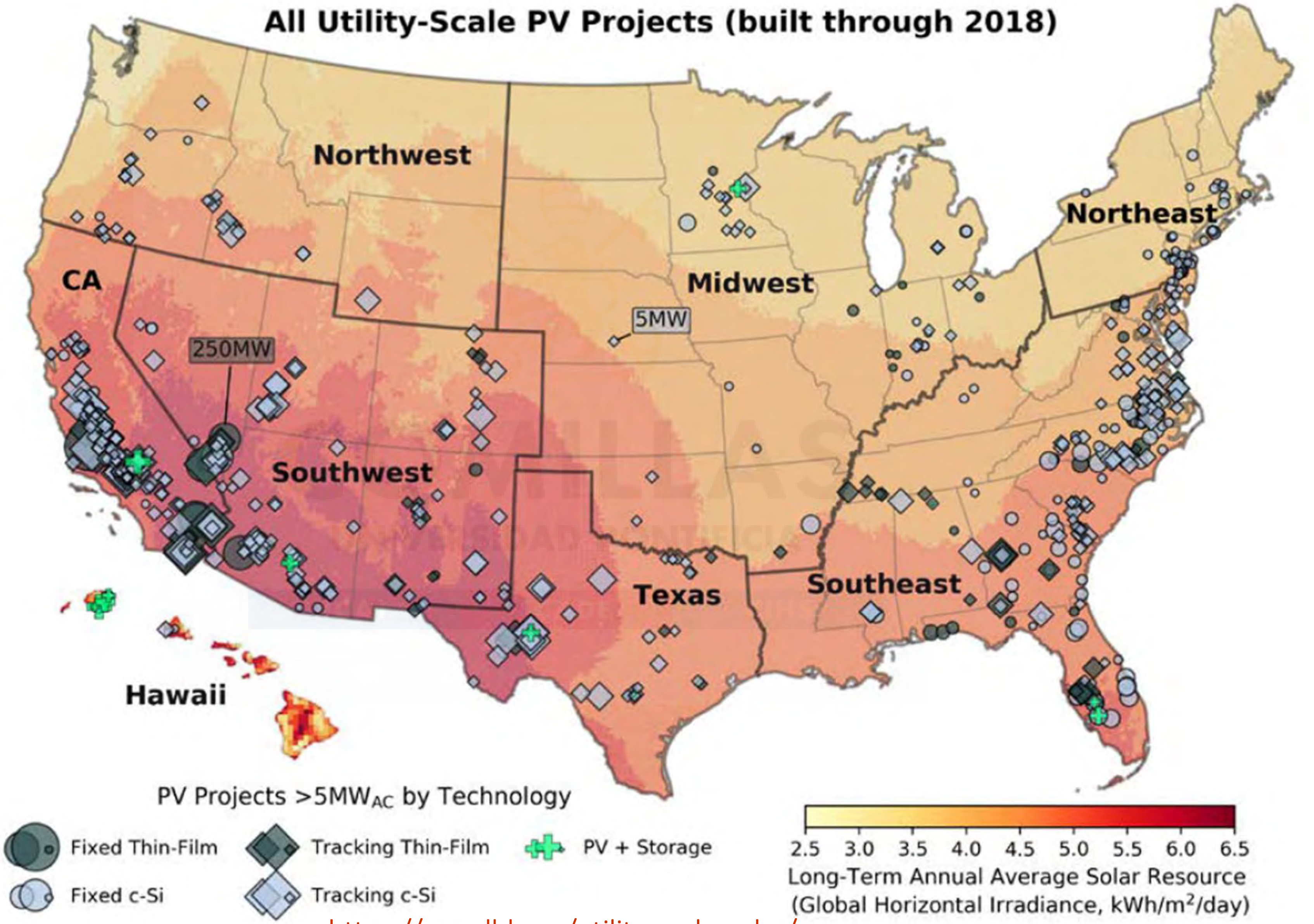
Major PV and CSP projects in the US



Please note that circle size reflects the capacity of the company's solar installation.

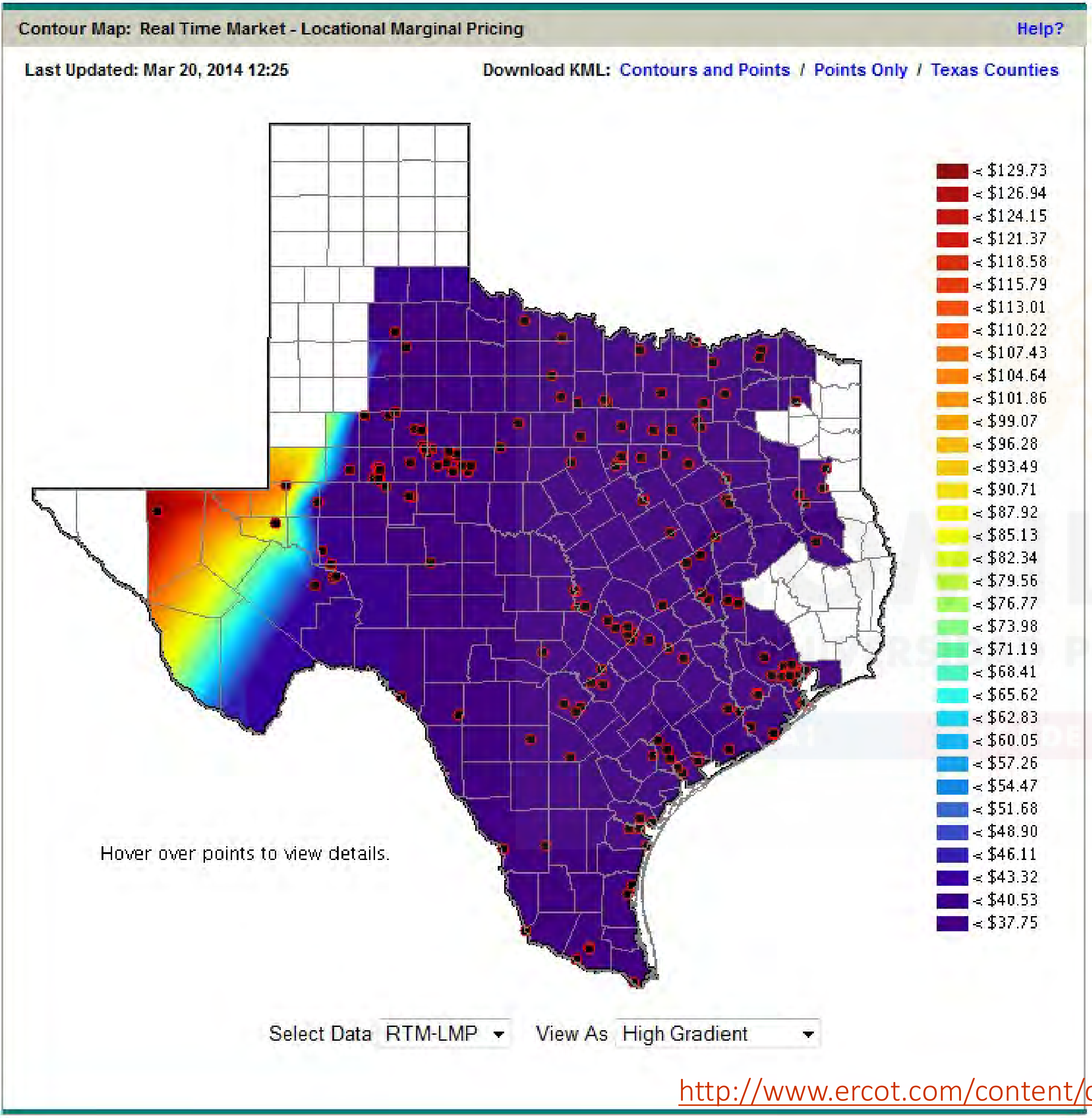
Last updated: Nov 2014
Send us additions or corrections via this form

Maps of Global Horizontal Irradiance (GHI) and Utility-Scale PV Projects



https://emp.lbl.gov/utility-scale-solar/

ERCOT. Locational marginal prices



Contour Map: Real Time Market - Locational Marginal Pricing

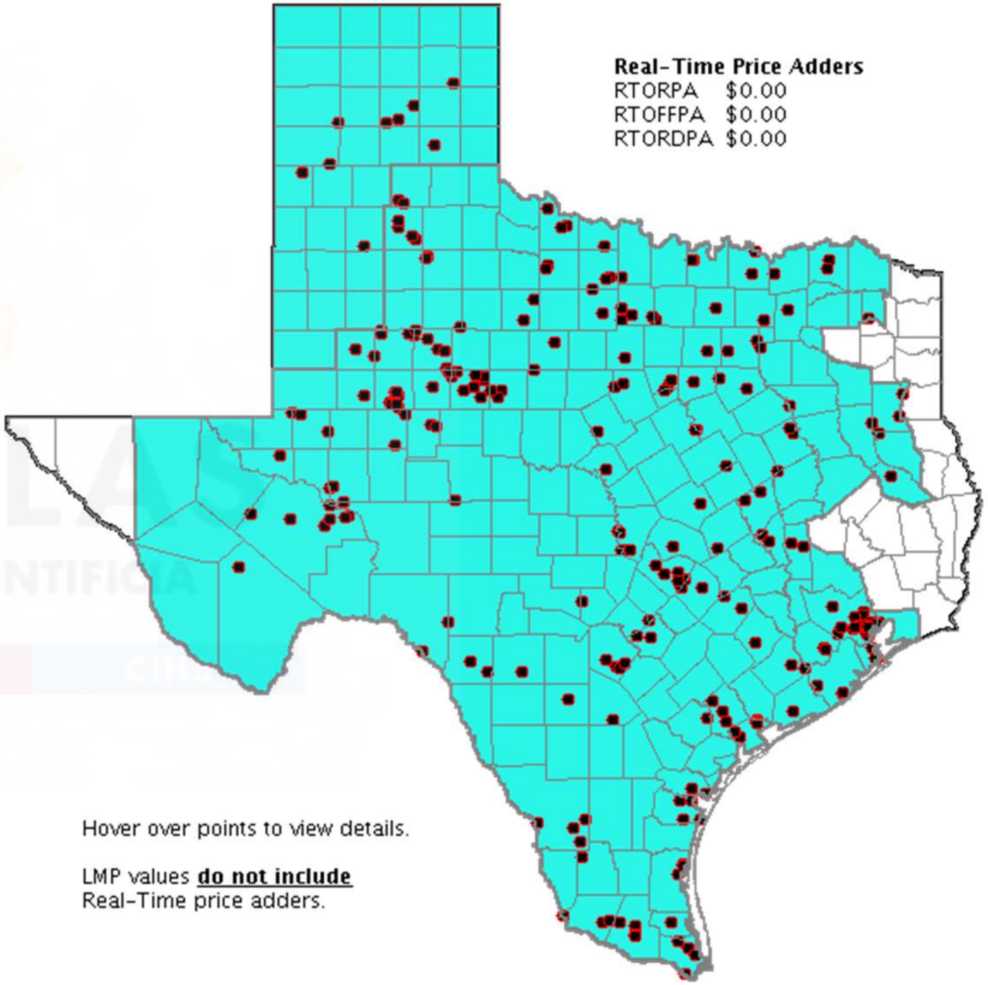
Last Updated: Mar 20, 2014 12:25

Download KML: Contours and Points / Points Only / Texas Counties

Hover over points to view details.

Select Data RTM-LMP

View As High Gradient



Real-Time Price Adders

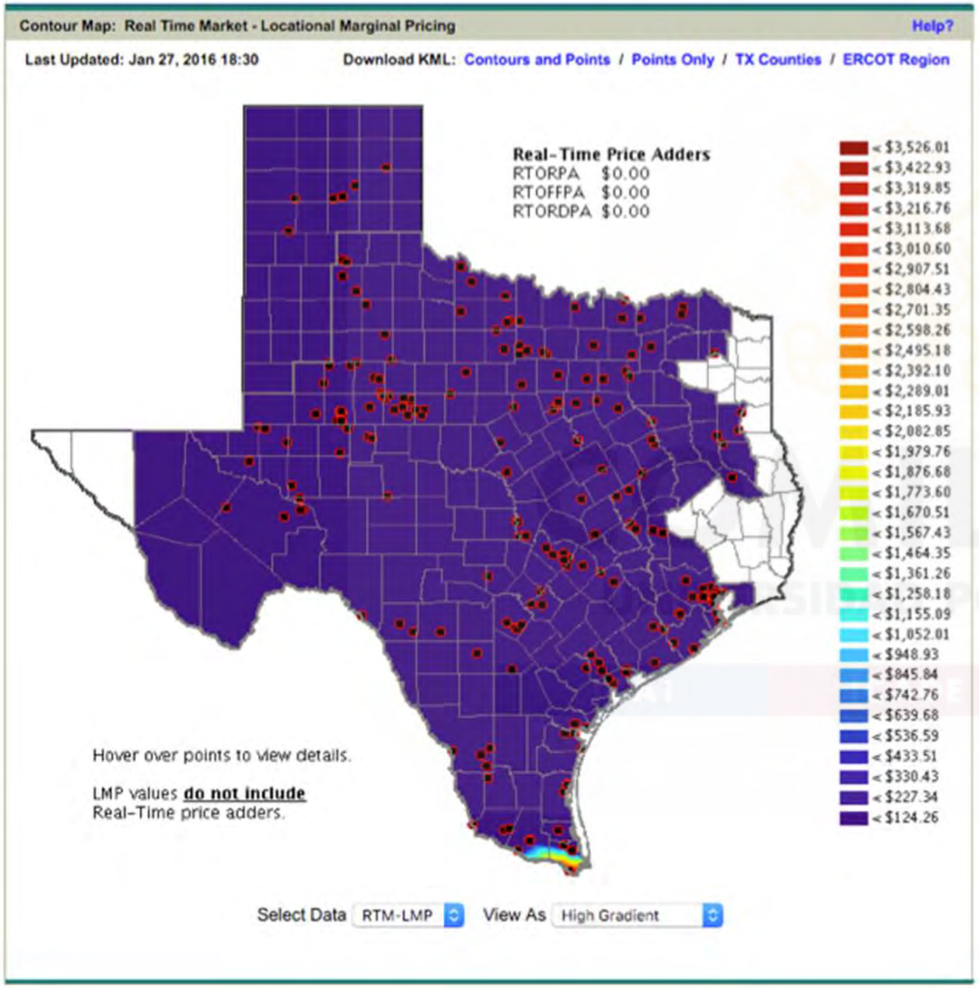
RTORPA	$0.00
RTOFFPA	$0.00
RTORDPA	$0.00

Hover over points to view details.

LMP values **do not include** Real-Time price adders.

http://www.ercot.com/content/cdr/contours/rtmLmpHg.html

ERCOT. Locational marginal prices



Contour Map: Real Time Market - Locational Marginal Pricing

Last Updated: Jan 27, 2016 18:30

Download KML: Contours and Points / Points Only / TX Counties / ERCOT Region

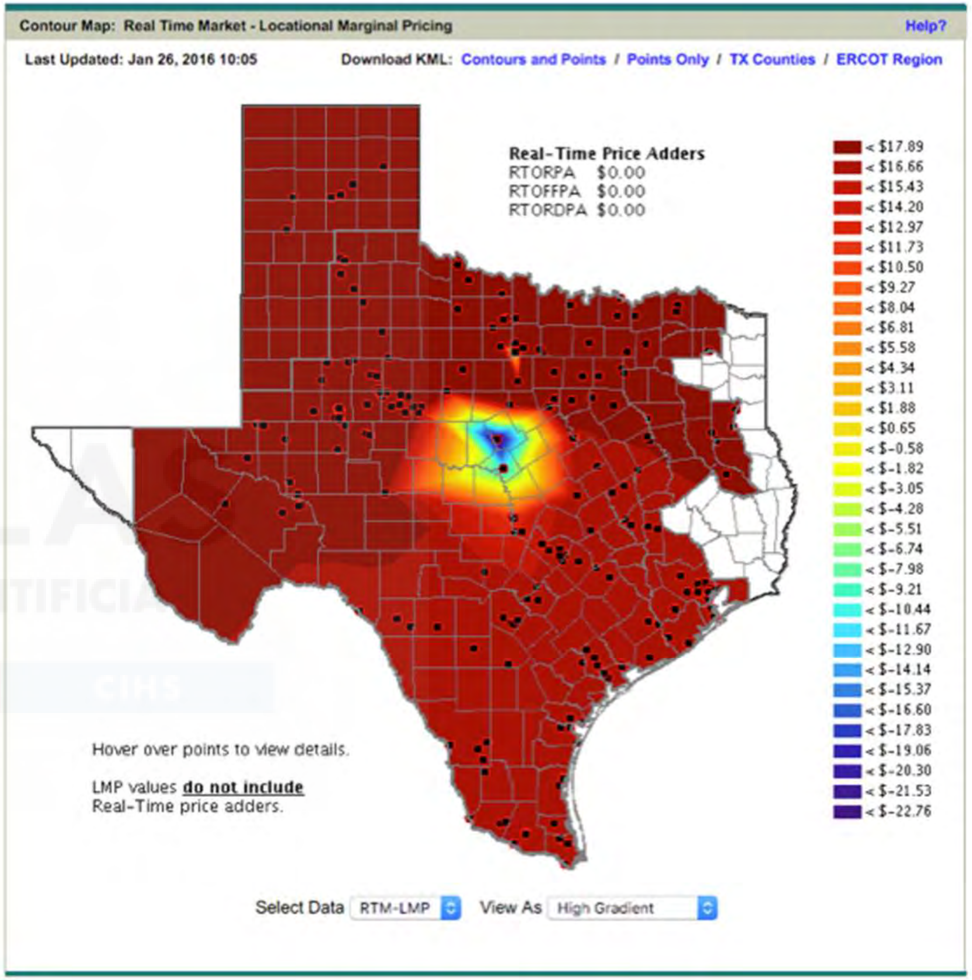
Real-Time Price Adders
RTORPA $0.00
RTOFFPA $0.00
RTORDPA $0.00

Hover over points to view details.

LMP values **do not include** Real-Time price adders.

Select Data: RTM-LMP

View As: High Gradient



Contour Map: Real Time Market - Locational Marginal Pricing

Last Updated: Jan 26, 2016 10:05

Download KML: Contours and Points / Points Only / TX Counties / ERCOT Region

Real-Time Price Adders
RTORPA $0.00
RTOFFPA $0.00
RTORDPA $0.00

Hover over points to view details.

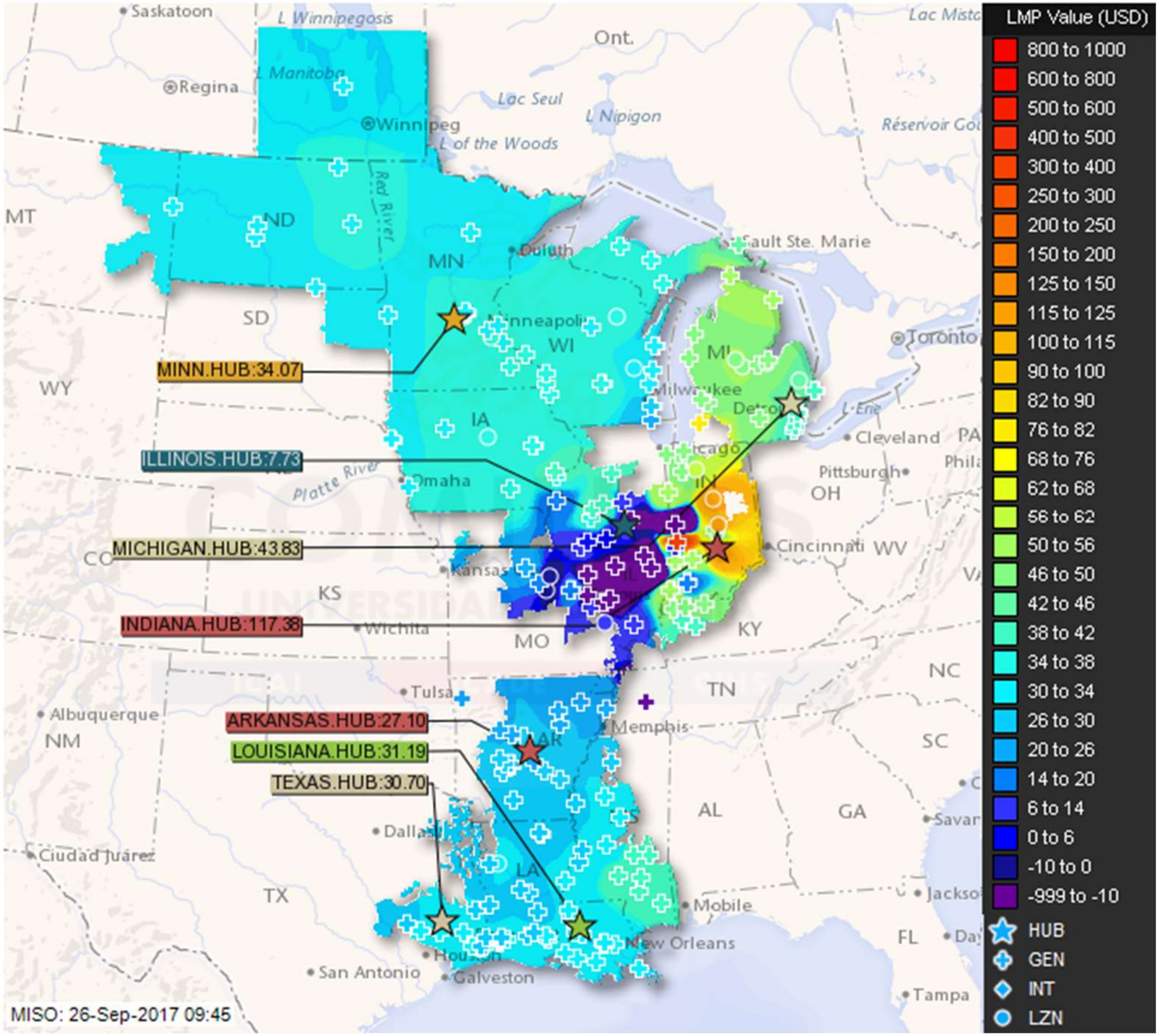
LMP values **do not include** Real-Time price adders.

Select Data: RTM-LMP

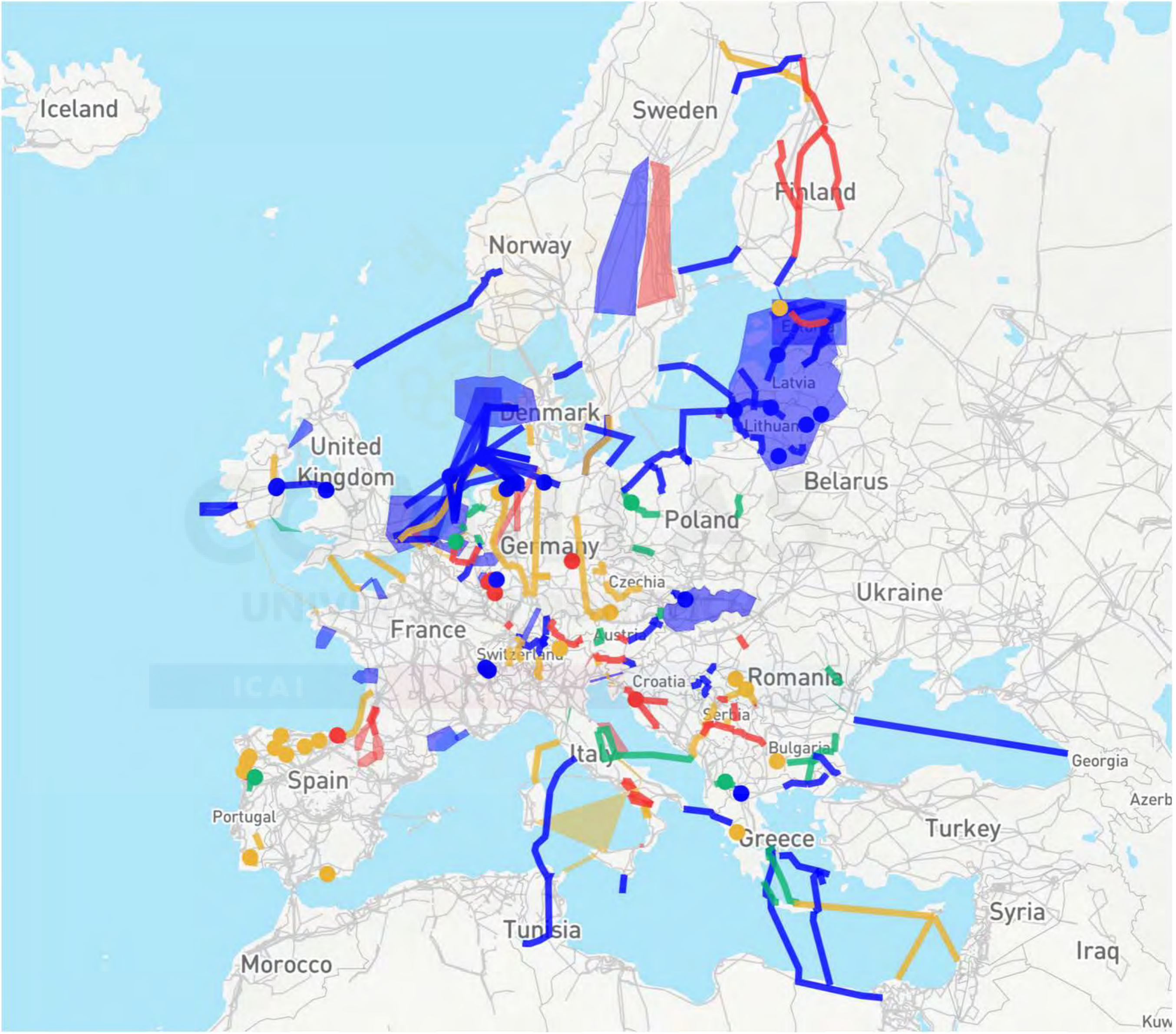
View As: High Gradient

http://www.ercot.com/content/cdr/contours/rtmLmpHg.html

MISO (Midcontinent Independent System Operator). Locational marginal prices



(Ten-Year Network Development Plan) TYNDP 2022

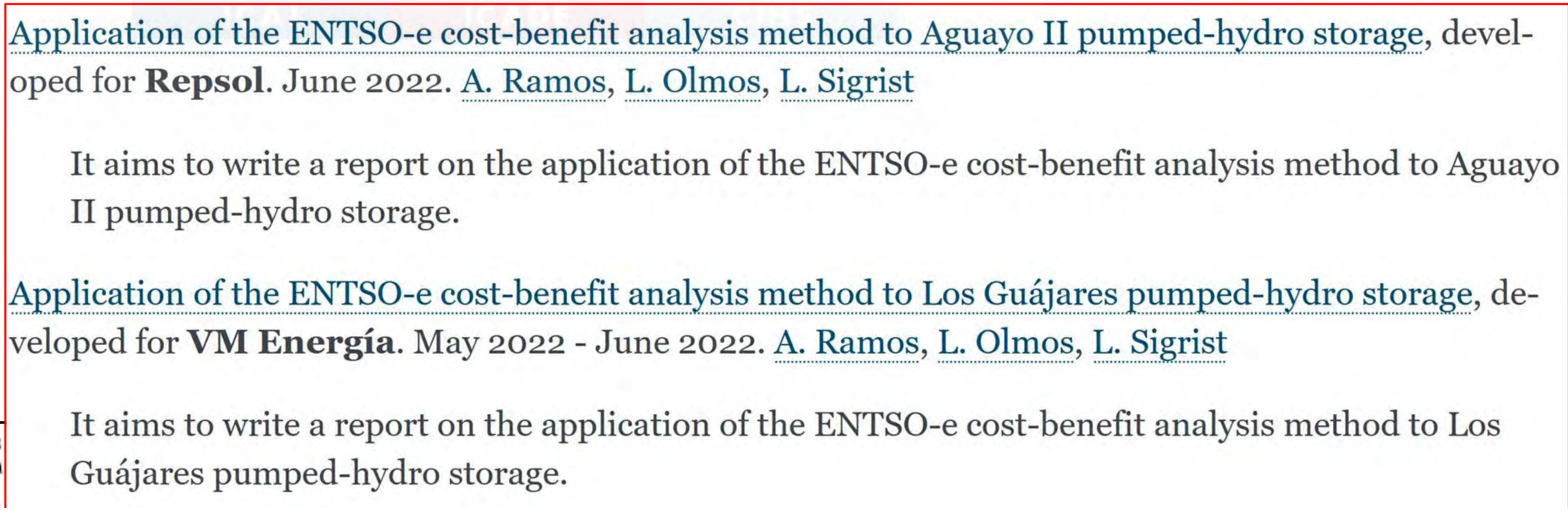


Projects of Common Interest (PCI)

Selected based on 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 in energy markets by offering alternatives to consumers
4. Improve the security of the 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.

https://ec.europa.eu/energy/topics/infrastructure/projects-common-interest_en



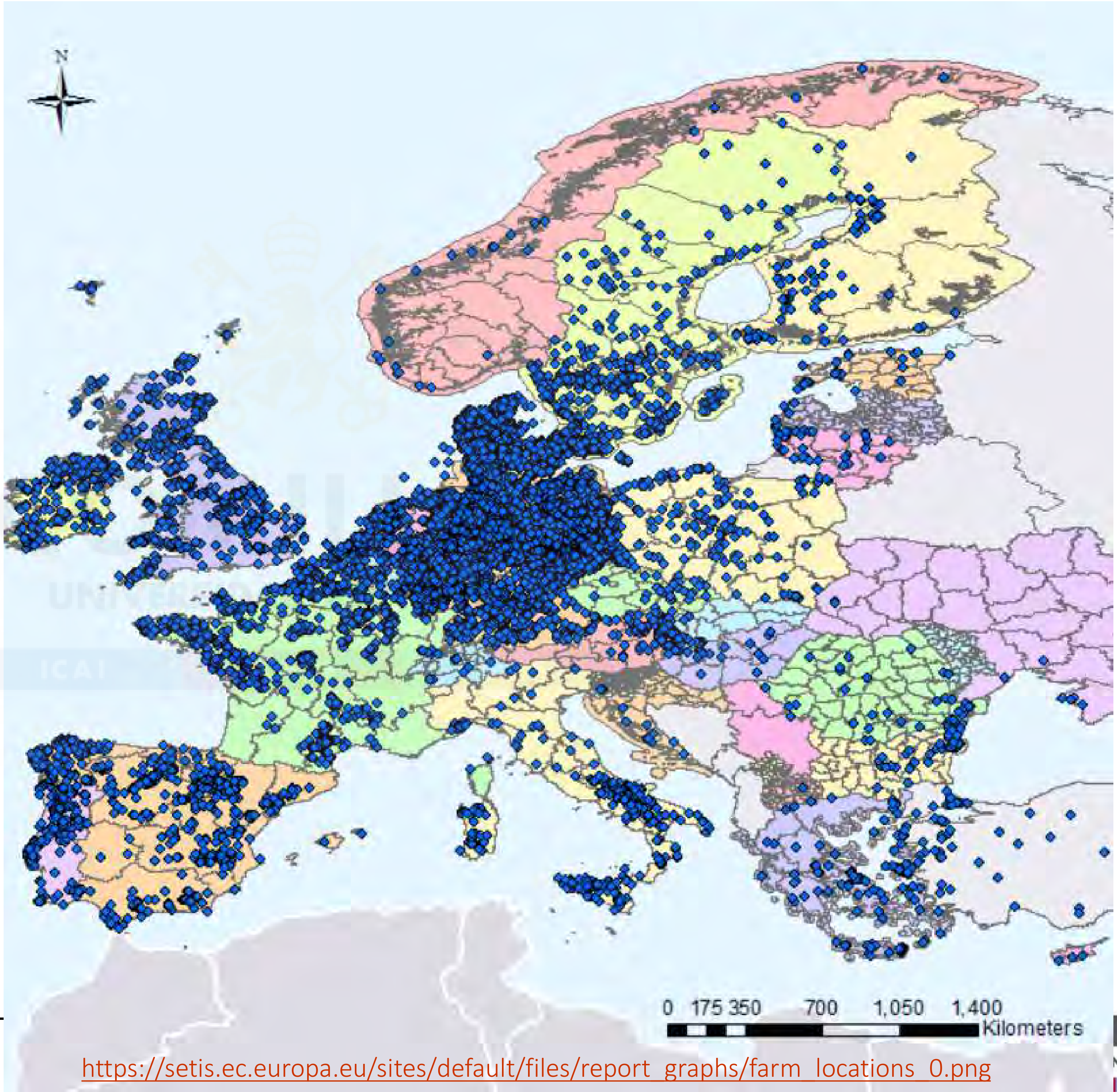
Application of the ENTSO-e cost-benefit analysis method to Aguayo II pumped-hydro storage, developed for **Repsol**. June 2022. A. Ramos, L. Olmos, L. Sigrist

It aims to write a report on the application of the ENTSO-e cost-benefit analysis method to Aguayo II pumped-hydro storage.

Application of the ENTSO-e cost-benefit analysis method to Los Guájares pumped-hydro storage, developed for **VM Energía**. May 2022 - June 2022. A. Ramos, L. Olmos, L. Sigrist

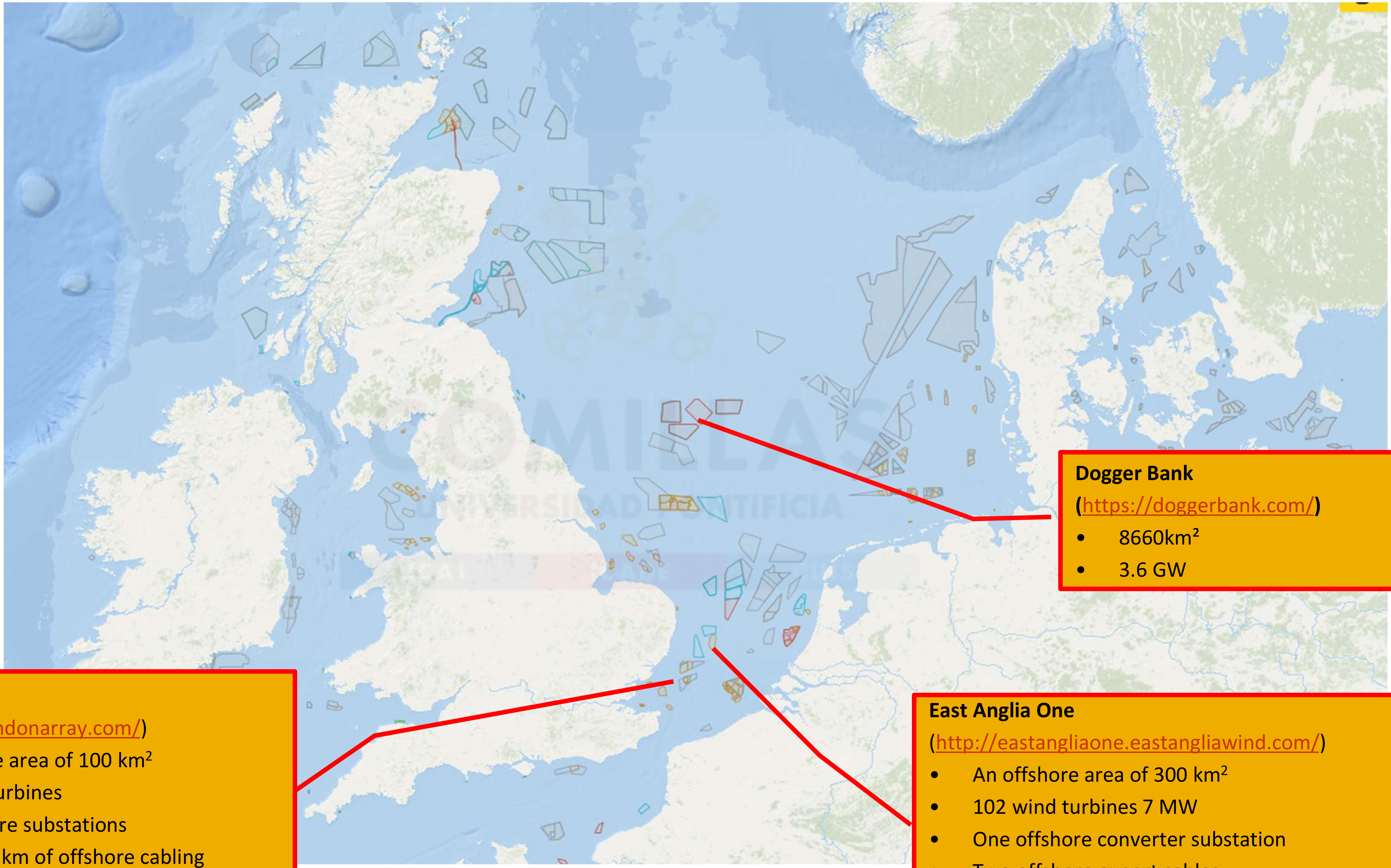
It aims to write a report on the application of the ENTSO-e cost-benefit analysis method to Los Guájares pumped-hydro storage.

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 and Baltic Sea



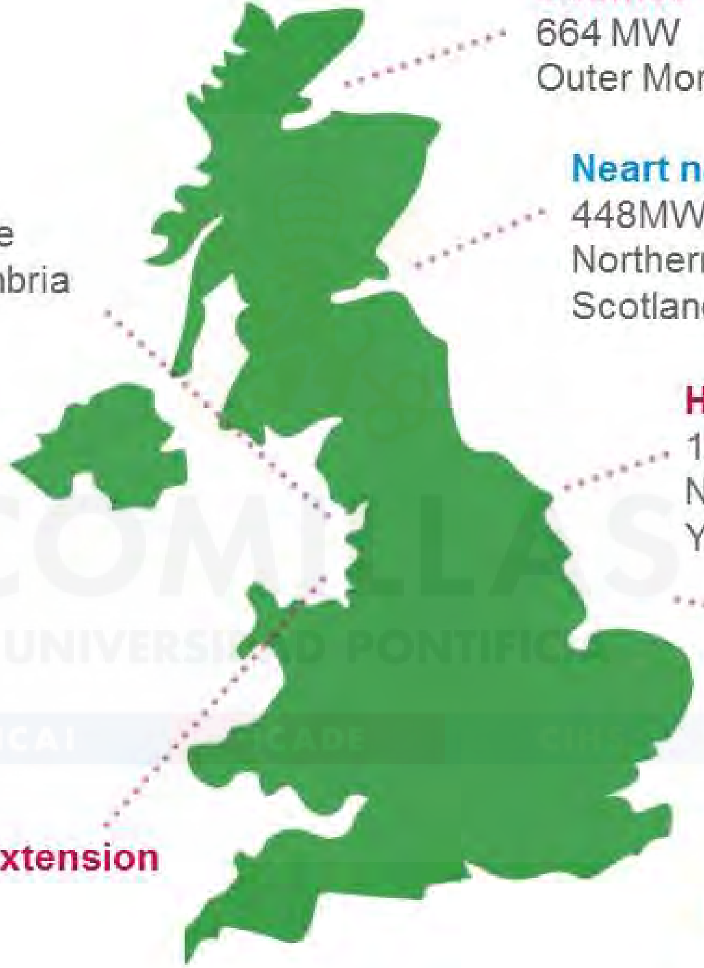
Dogger Bank
(https://doggerbank.com/)
- 8660km^2
- 3.6 GW

London Array
(http://www.londonarray.com/)
- An offshore area of 100 km^2
- 175 wind turbines
- Two offshore substations
- Nearly 450 km of offshore cabling
- One onshore substation
- 630 MW of capacity

East Anglia One
(http://eastangliaone.eastangliawind.com/)
- An offshore area of 300 km^2
- 102 wind turbines 7 MW
- One offshore converter substation
- Two offshore export cables
- 714 MW of capacity

https://www.4coffshore.com/offshorewind/

Projects awarded Contracts for Difference in UK (2015)



Beatrice
664 MW
Outer Moray Firth, Scotland

Walney Extension
660 MW
Irish Sea 10km WSW off the
Walney Island coast in Cumbria

Neart na Gaoithe (NNG)
448MW
Northern North Sea (Forth),
Scotland

Hornsea 1
1200 MW
North Sea, off the
Yorkshire coast

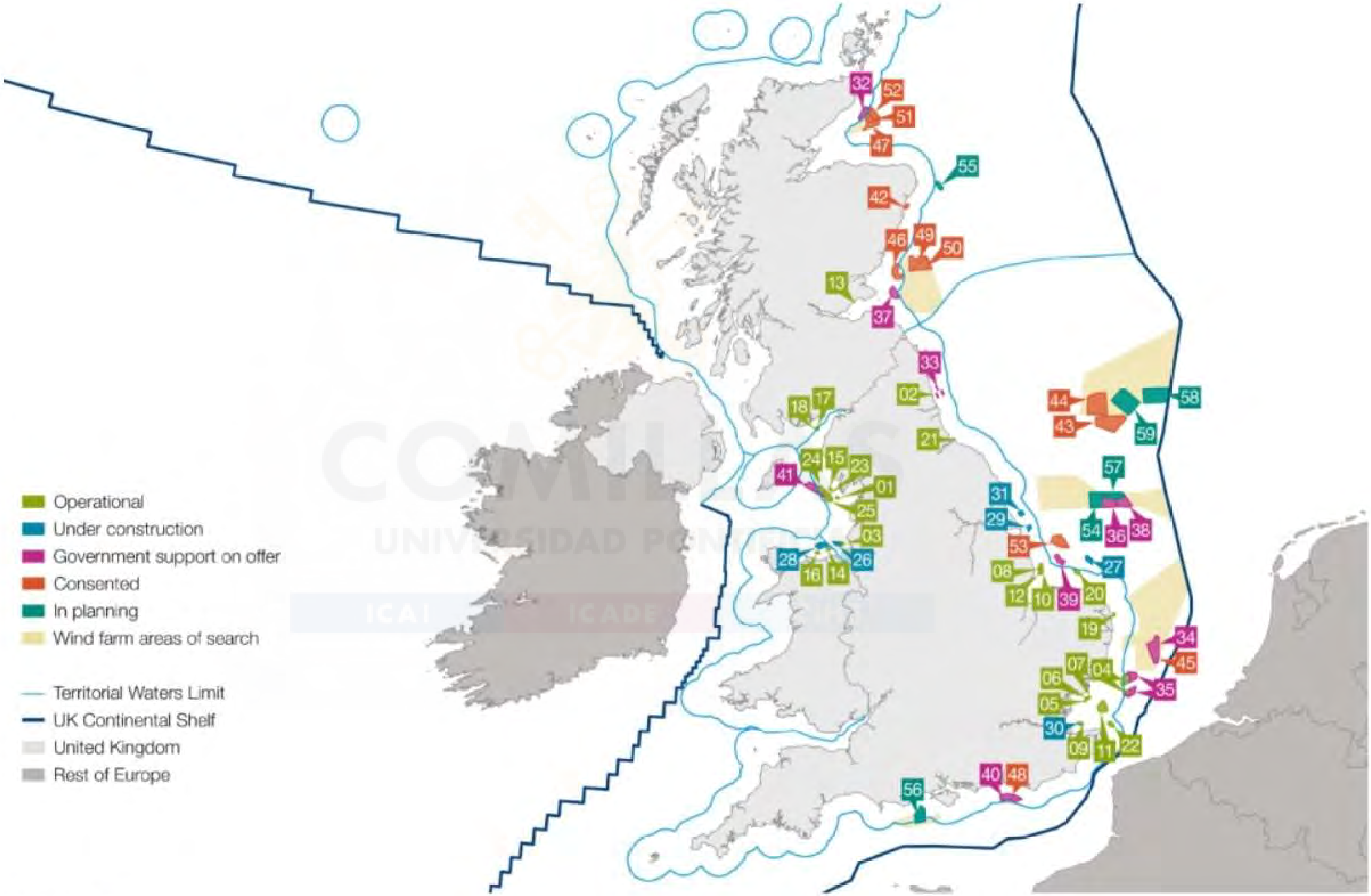
Dudgeon
402 MW
The Wash north of Cromer,
Norfolk

Burbo Bank Extension
258 MW
Liverpool Bay

East Anglia ONE
714MW
Southern North Sea (Thames)
East of England

https://www.gov.uk/government/publications/uk-offshore-wind-opportunities-for-trade-and-investment/uk-offshore-wind-opportunities-for-trade-and-investment

Offshore wind (UK) map – May 2015

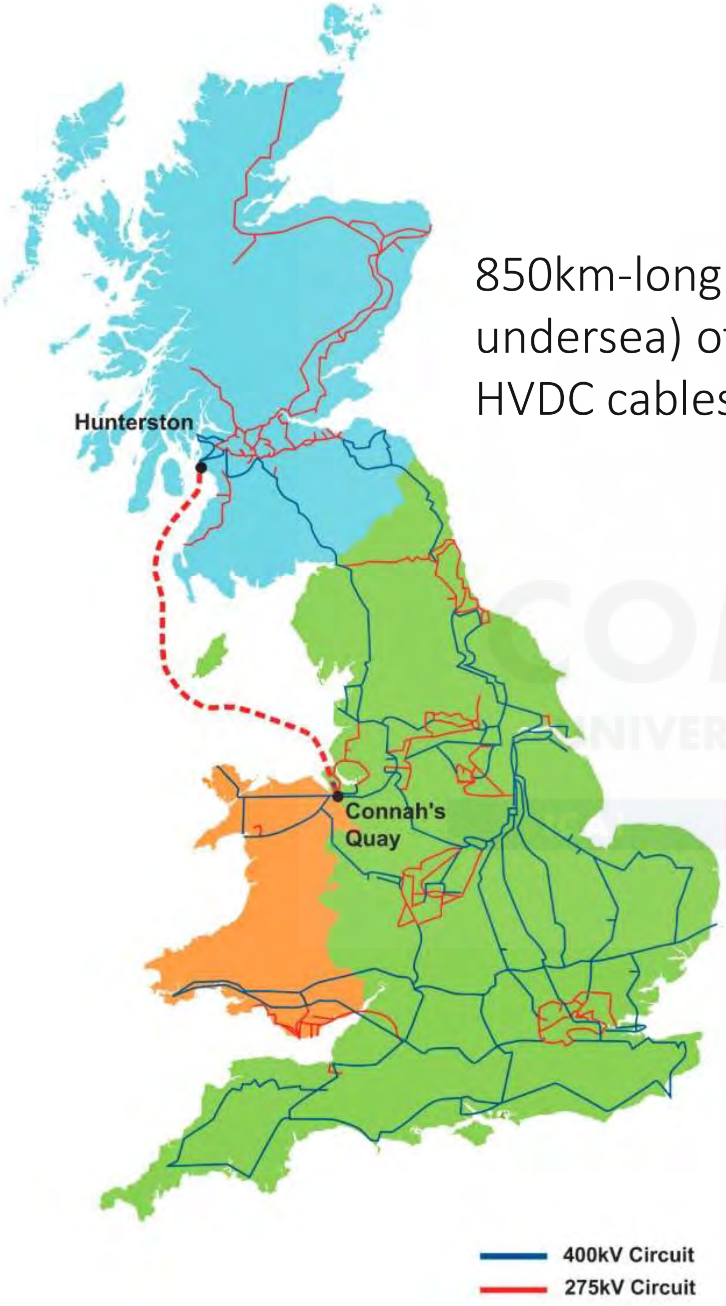


(c) Crown Estate

https://www.gov.uk/government/publications/uk-offshore-wind-opportunities-for-trade-and-investment/uk-offshore-wind-opportunities-for-trade-and-investment

Western Link, UK

850km-long (770 km undersea) of 2.2GW HVDC cables

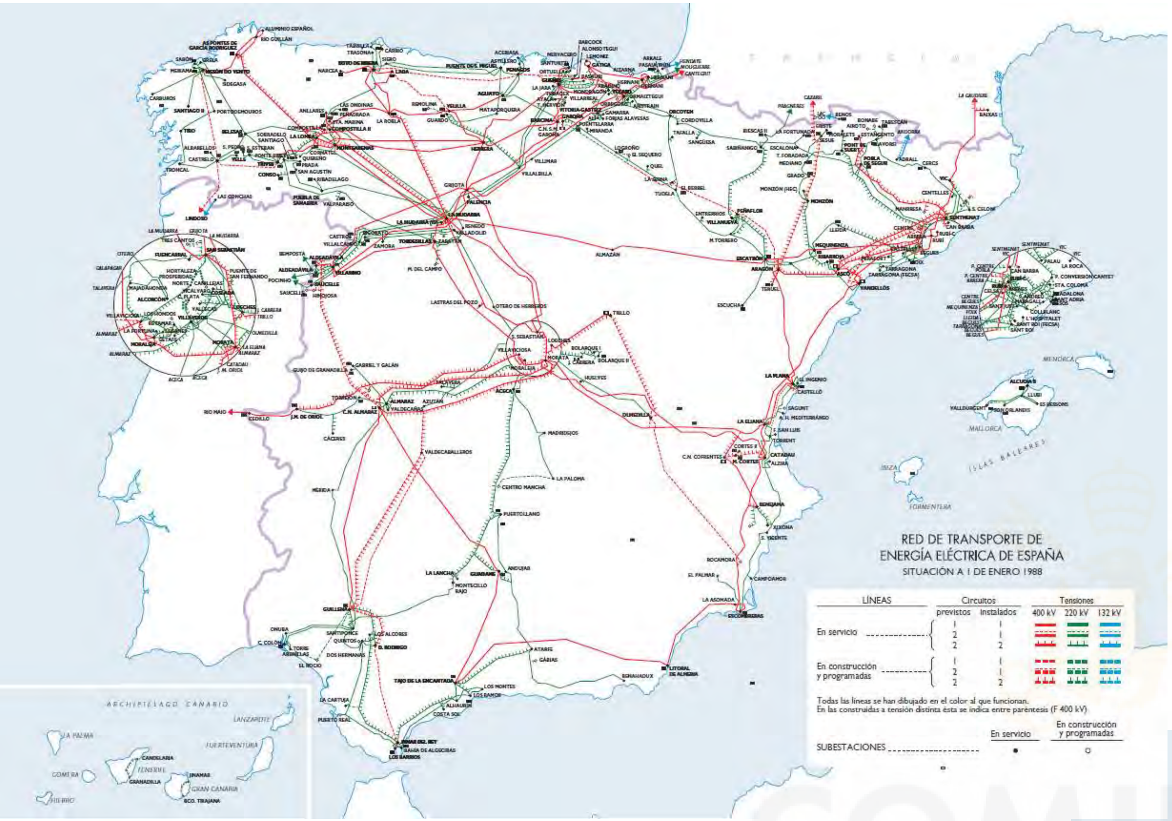


Eastern Green Link 2, UK

440km-long subsea of two 2GW HVDC cables

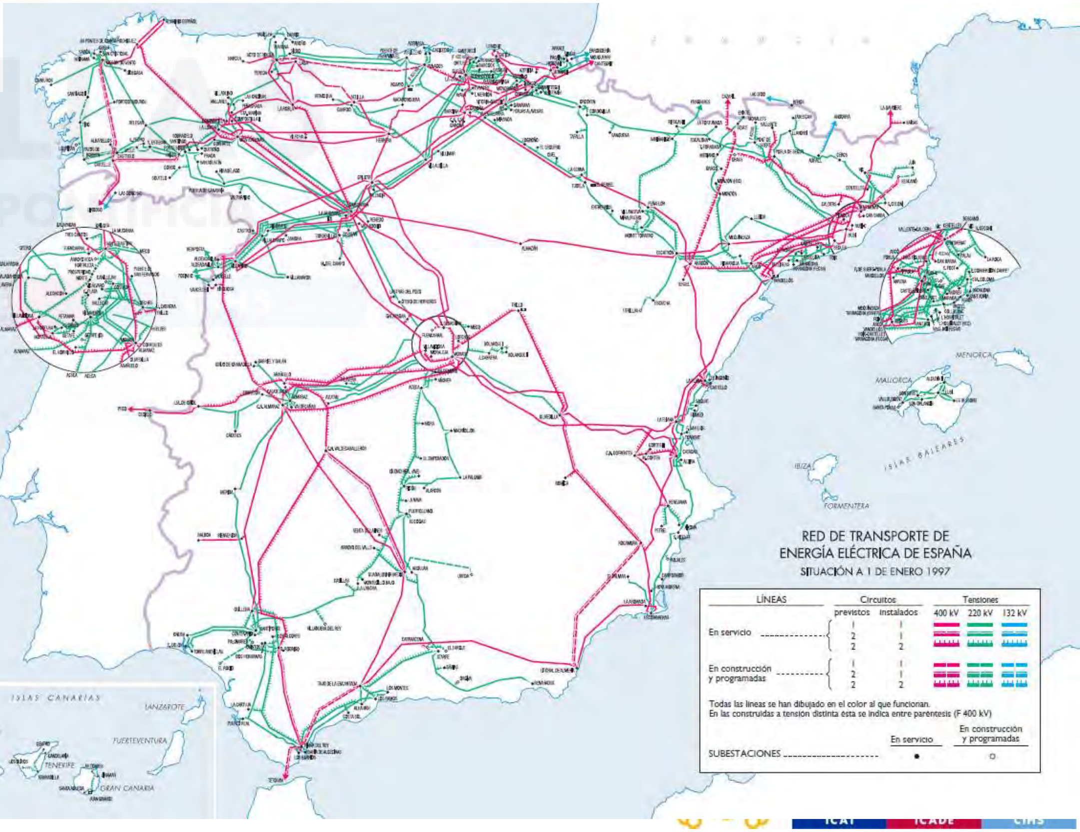
https://www.iberdrola.com/about-us/lines-business/flagship-projects/eastern-link-electric-underwater-line

Spanish Grid



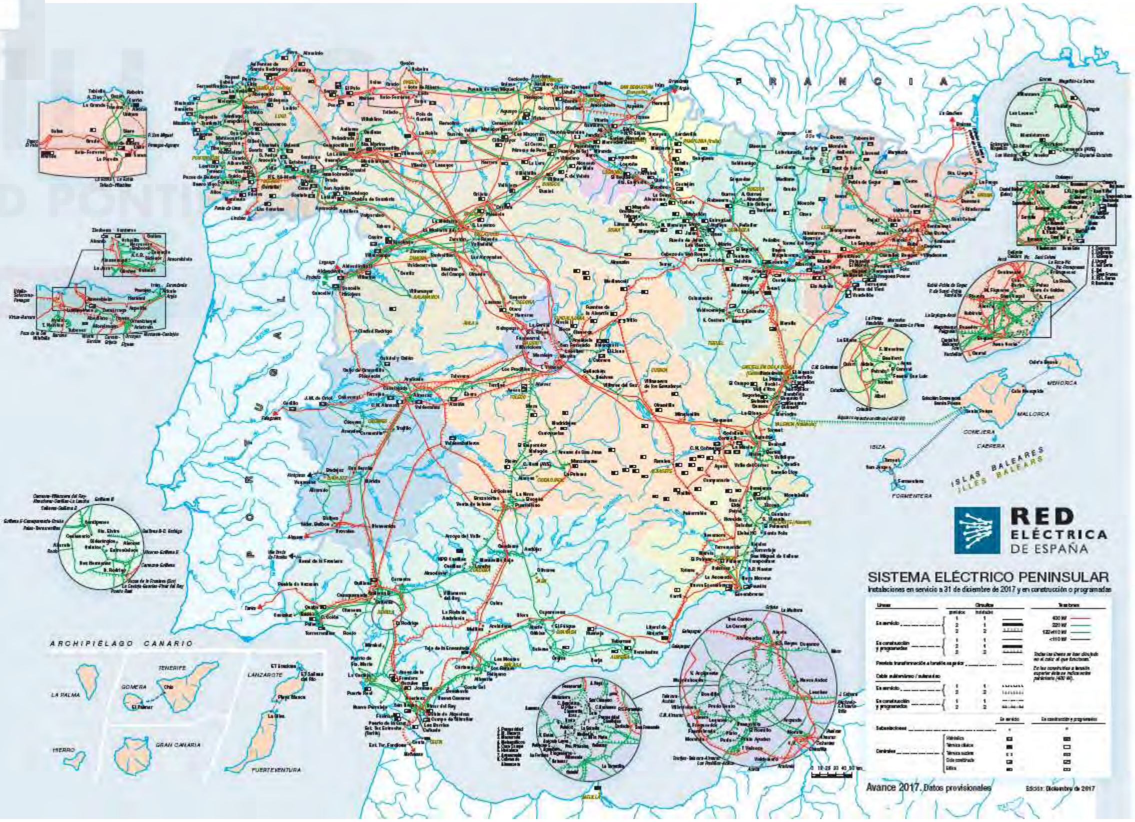
1988

1997



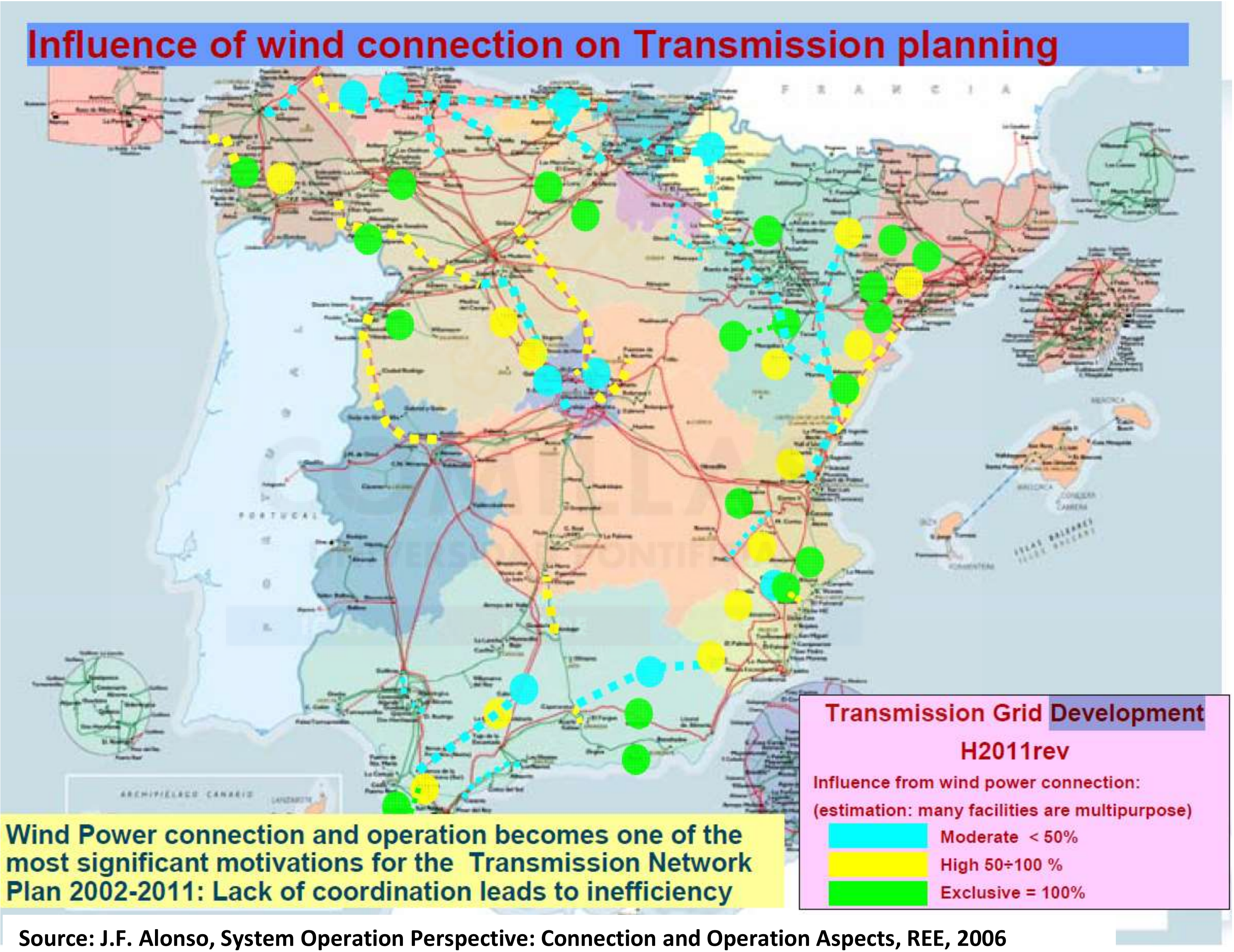
Spanish Grid

2004



2017

Influence of wind connection on transmission planning



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

Transmission Grid Development

H2011rev

Influence from wind power connection:

(estimation: many facilities are multipurpose)

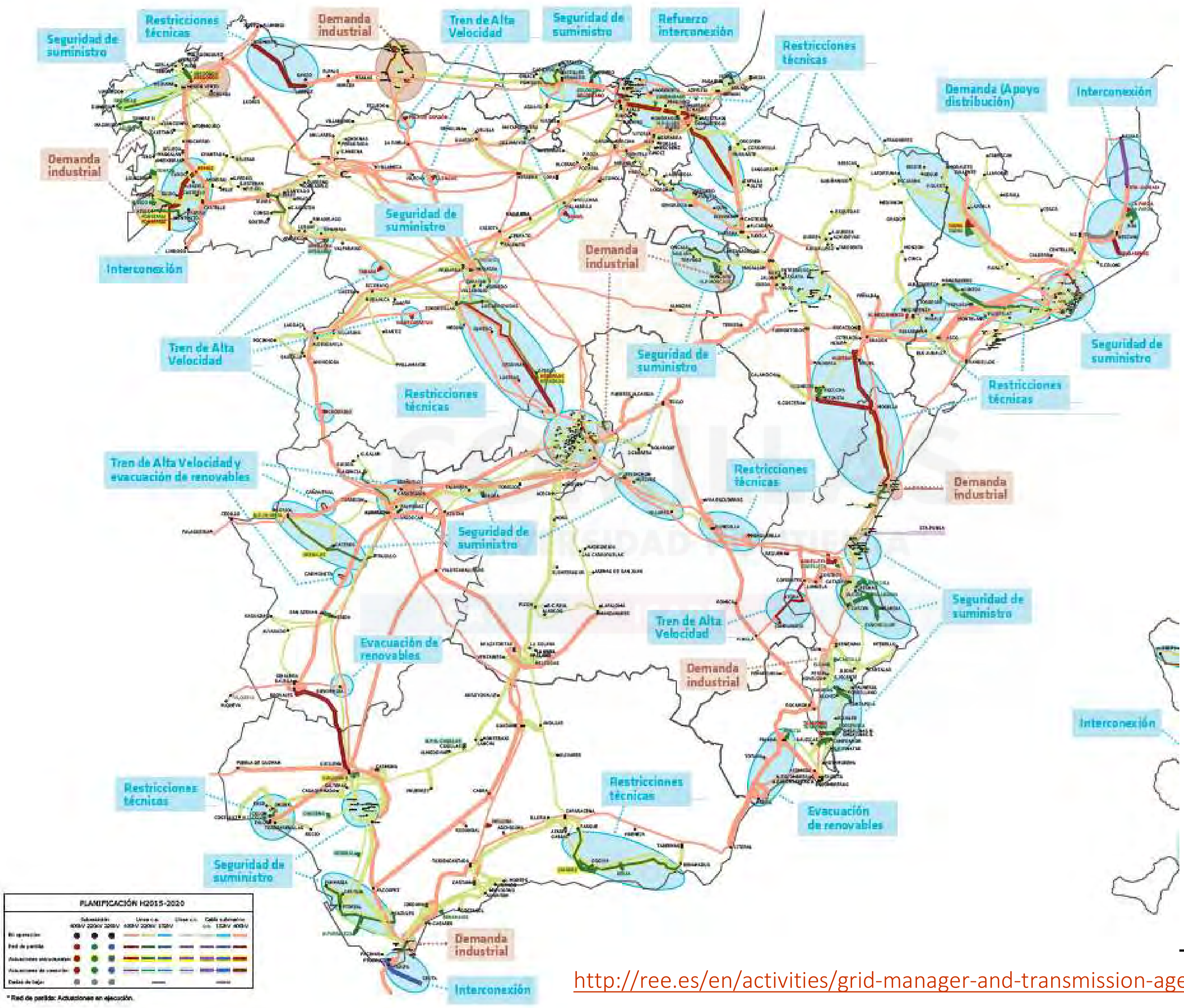
🟦 Moderate < 50%

🟨 High 50÷100 %

🟩 Exclusive = 100%

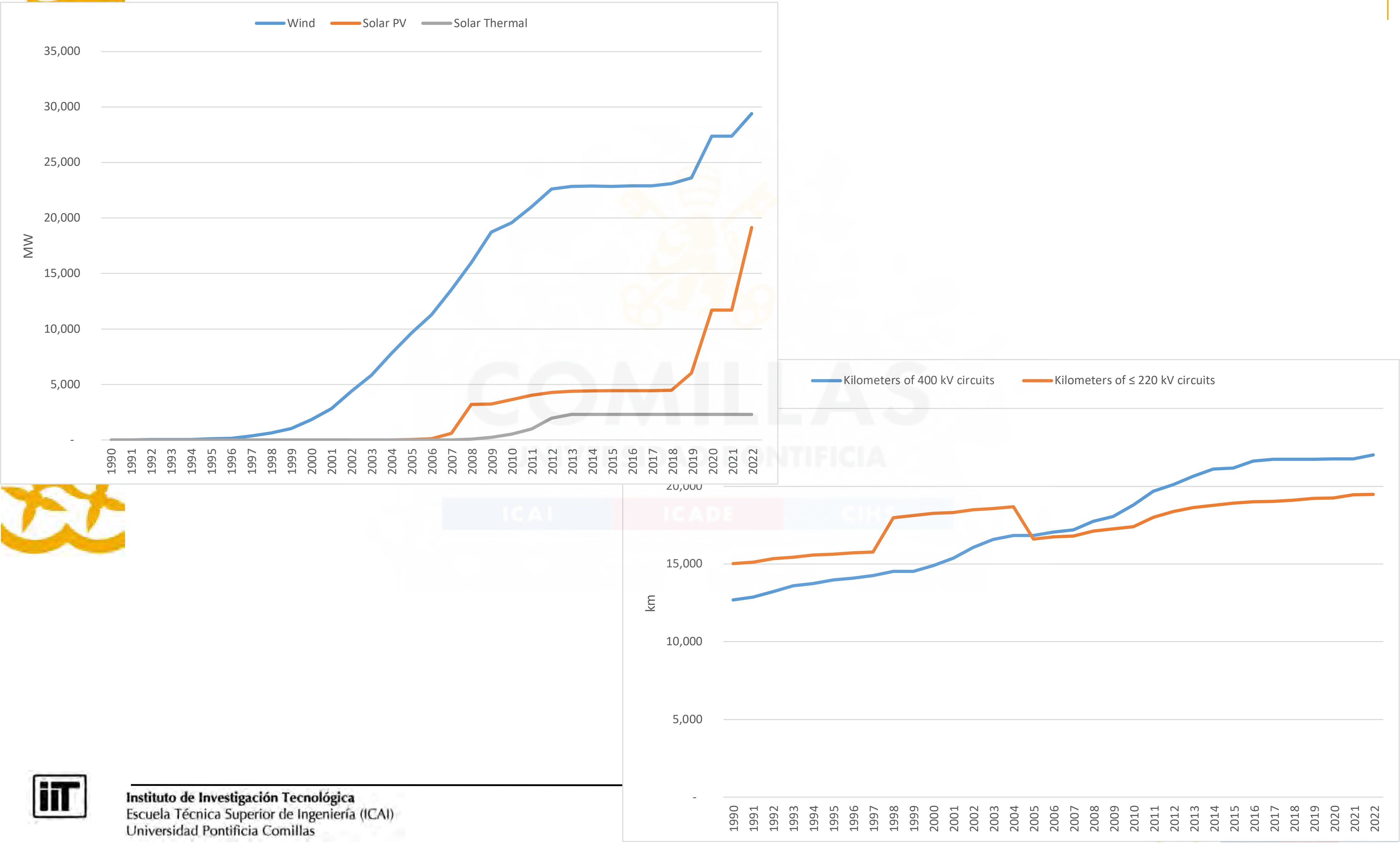
Source: J.F. Alonso, System Operation Perspective: Connection and Operation Aspects, REE, 2006

REE Transmission Planning 2015-2020



http://ree.es/en/activities/grid-manager-and-transmission-agent/grid-planning-an-development

Spanish high voltage transmission network (1990-2022)



1. Transmission Expansion Planning
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5. Prototype TEP. Computer implementation
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2

Simple TEP models

Centralized TEP model

$$\min \sum_{ij} f'_{ij} IC_{ij} + \sum_{t} v_t P_t + \sum_{i} v' ENS_i$$

Transmission investment cost + thermal variable costs + ENS cost

$$\sum_{t\in i} P_t + \sum_{j} F_{ji} - \sum_{j} F_{ij} + ENS_i = D_i \quad \forall i$$

Generation and load balance for each node

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

$$-\bar{F}'_{ij}(1 - IC_{ij}) \le F_{ij} - \frac{\theta_i - \theta_j}{X_{ij}} S_B \le \bar{F}'_{ij}(1 - IC_{ij}) \quad \forall ij$$

DC linearized load flow for existing and candidate lines

$$-\bar{F}_{ij} \le F_{ij} \le \bar{F}_{ij} \quad \forall ij$$

$$-\bar{F}_{ij} IC_{ij} \le F_{ij} \le \bar{F}_{ij} IC_{ij} \quad \forall ij$$

$$\theta_i \ \text{free}, \theta_{i*} = 0$$

Flow limits for existing & candidate lines. Reference voltage angle

$$0 \le ENS_i \le D_i \quad \forall i$$

$$0 \le P_t \le \bar{P}_t \quad \forall t$$

Thermal operating bounds

$$IC_{ij} \in \{0, 1\} \quad \forall ij$$

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 a 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

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

$$\sum_{t \in i} P_{t} + \sum_{j} F_{ji} - \sum_{j} F_{ij} + ENS_{i} = D_{i} \quad : \pi_{i} \qquad \forall i$$

$$F_{ij} - \frac{\theta_{i} - \theta_{j}}{X_{ij}} S_{B} = 0 \qquad \forall ij$$

$$-\bar{F}'_{ij}(1 - IC_{ij}) \leq F_{ij} - \frac{\theta_{i} - \theta_{j}}{X_{ij}} S_{B} \leq \bar{F}'_{ij}(1 - IC_{ij}) \qquad \forall ij$$

$$-\bar{F}_{ij} \leq F_{ij} \leq \bar{F}_{ij} \qquad \forall ij$$

$$-\bar{F}_{ij} IC_{ij} \leq F_{ij} \leq \bar{F}_{ij} IC_{ij} \qquad \forall ij$$

$$\theta_{i} \ \text{free}, \theta_{i*} = 0$$

$$0 \leq ENS_{i} \leq D_{i} \qquad \forall i$$

$$IC_{ij} \in \{0, 1\} \qquad \forall ij$$

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

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

Thermal revenues - variable costs

$$0 \le P_t \le \overline{P}_t \qquad \forall t$$

Thermal operating bounds

GenCos market equilibrium problem (MEP)

- Each company solves independently its own profit maximization problem

Gen Company 1

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

$$0 \leq P_t \leq \overline{P}_t \qquad \forall t$$

Gen Company e

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

$$0 \leq P_t \leq \overline{P}_t \qquad \forall t$$

Gen Company E

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

$$0 \leq P_t \leq \overline{P}_t \qquad \forall t$$

Overall MEP + TEP

Bilevel optimization

TSO

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

$$\sum_{t \in i} P_{t} + \sum_{j} F_{ji} - \sum_{j} F_{ij} + ENS_{i} = D_{i} \quad : \pi_{i} \qquad \forall i$$

$$F_{ij} - \frac{\theta_{i} - \theta_{j}}{X_{ij}} S_{B} = 0 \qquad \forall ij$$

$$-\bar{F}'_{ij}(1 - IC_{ij}) \le F_{ij} - \frac{\theta_{i} - \theta_{j}}{X_{ij}} S_{B} \le \bar{F}'_{ij}(1 - IC_{ij}) \qquad \forall ij$$

$$-\bar{F}_{ij} \le F_{ij} \le \bar{F}_{ij} \qquad \forall ij$$

$$-\bar{F}_{ij} IC_{ij} \le F_{ij} \le \bar{F}_{ij} IC_{ij} \qquad \forall ij$$

$$\theta_{i} \ free, \theta_{i*} = 0$$

$$0 \le ENS_{i} \le D_{i} \qquad \forall i$$

$$IC_{ij} \in \{0, 1\} \qquad \forall ij$$

Gen Company 1

$$\max \sum_{i} \sum_{t \in i} \pi_{i} P_{t} - \sum_{t} v_{t} P_{t}$$

$$0 \le P_{t} \le \bar{P}_{t} \qquad \forall t$$

Gen Company e

$$\max \sum_{i} \sum_{t \in i} \pi_{i} P_{t} - \sum_{t} v_{t} P_{t}$$

$$0 \le P_{t} \le \bar{P}_{t} \qquad \forall t$$

Gen Company E

$$\max \sum_{i} \sum_{t \in i} \pi_{i} P_{t} - \sum_{t} v_{t} P_{t}$$

$$0 \le P_{t} \le \bar{P}_{t} \qquad \forall t$$

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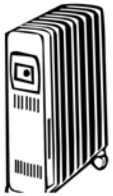
Modeling issues

Challenges for Transmission Expansion Planning (TEP)

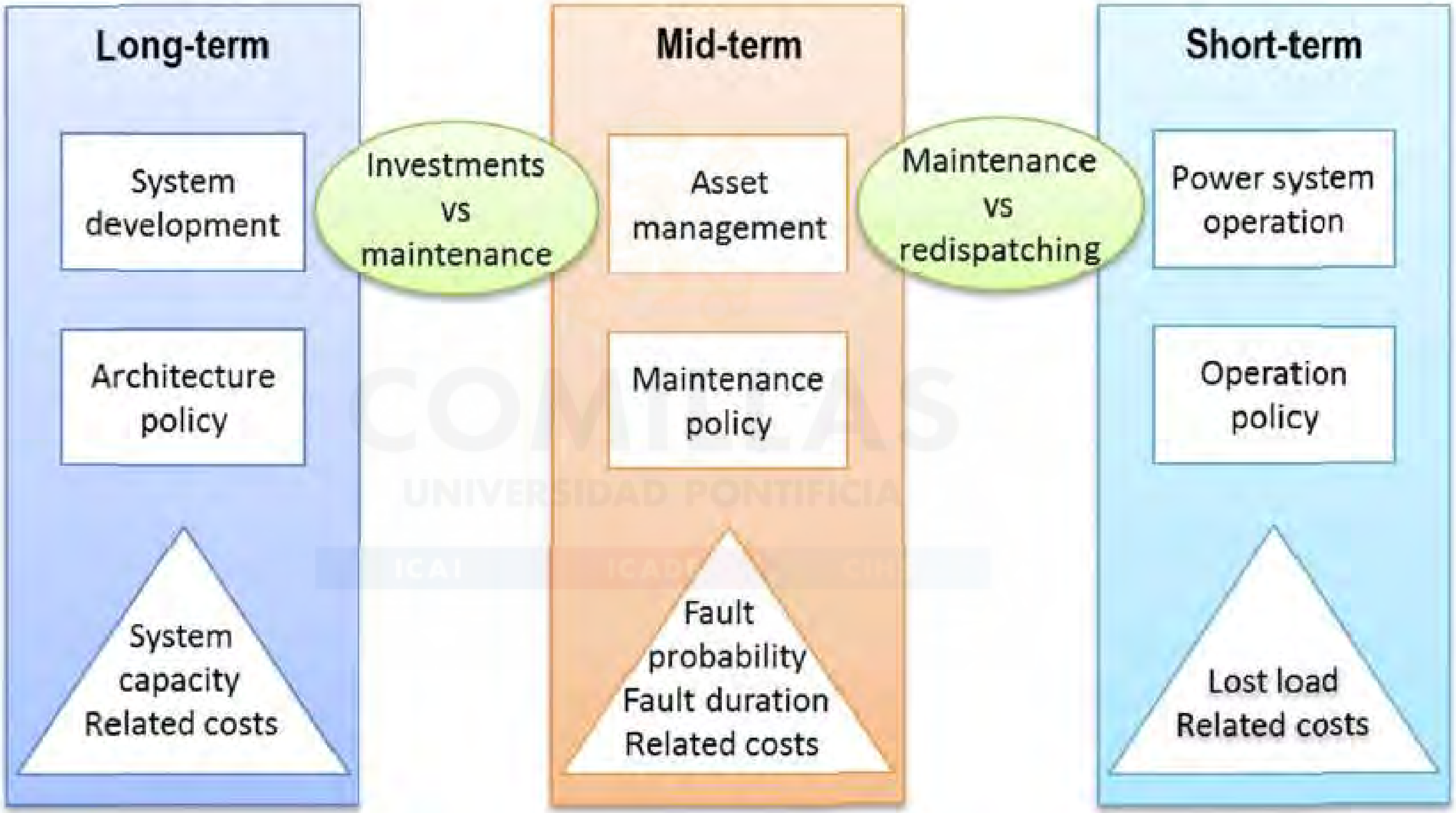
Spatial complexity: *Europe to smart cities*

Temporal complexity: *msec. to decades*

Stochastic complexity: *weather conditions and human behaviors*



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. A 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 transmission expansion planning?

- Independent entities make decisions
  - 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

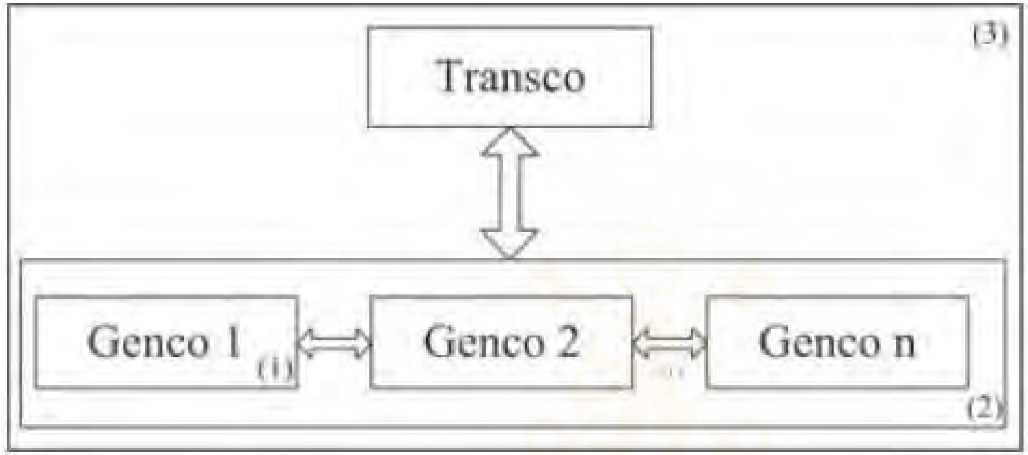


Figure 4.2: The proactive approach for generation-transmission investment game

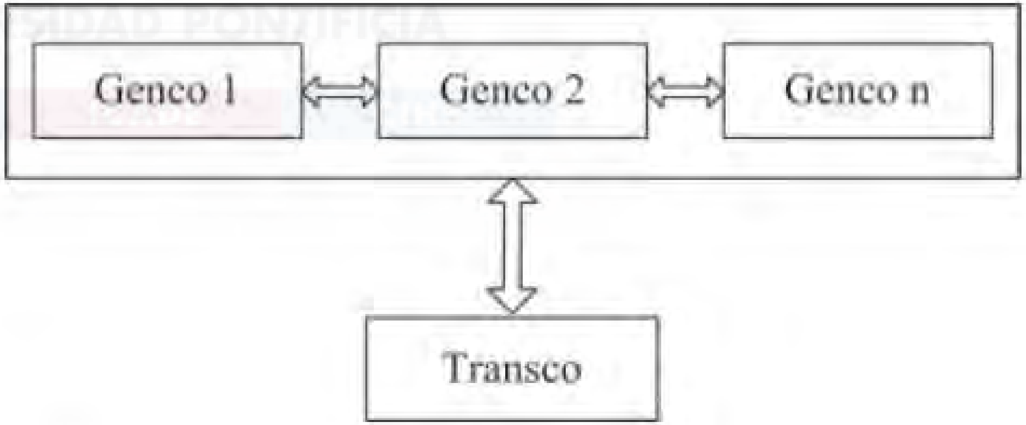


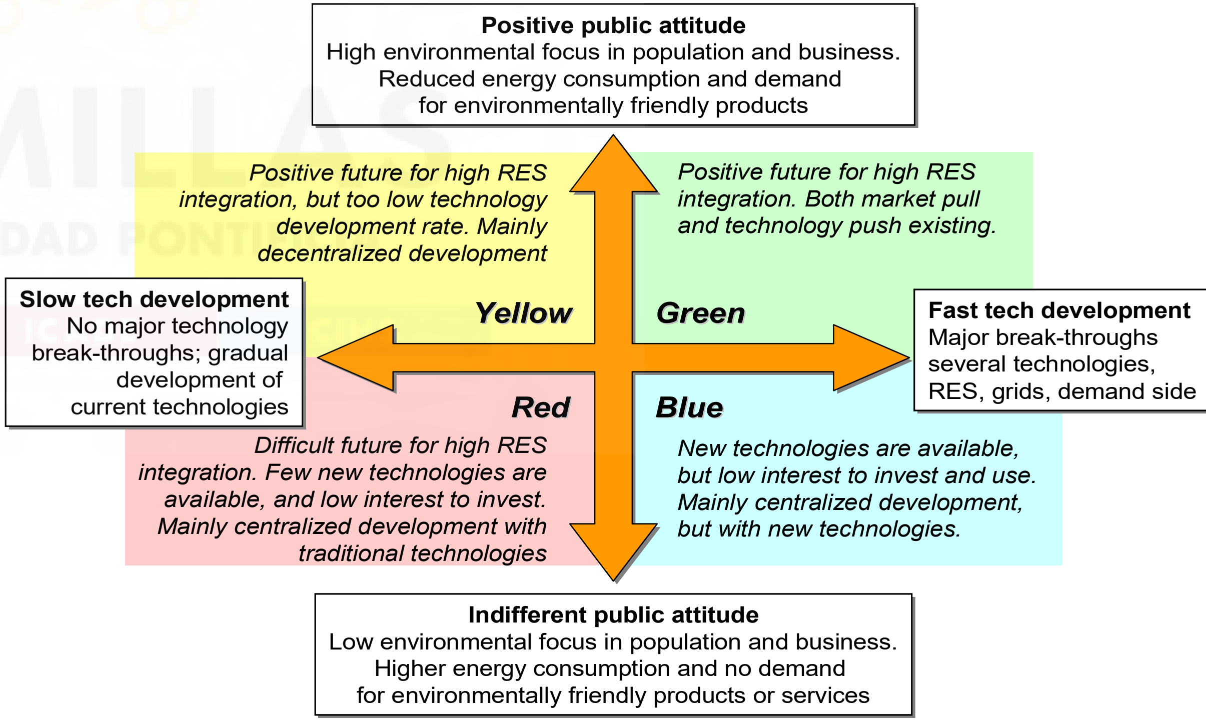
Figure 4.3: The reactive approach for generation-transmission investment game

Y. Tohidi *Optimal Long-Term Generation-transmission Planning in the Context of Multiple TSOs*. PhD Thesis. KTH, 2016

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

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

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

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

Fast tech development
Major break-throughs 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

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

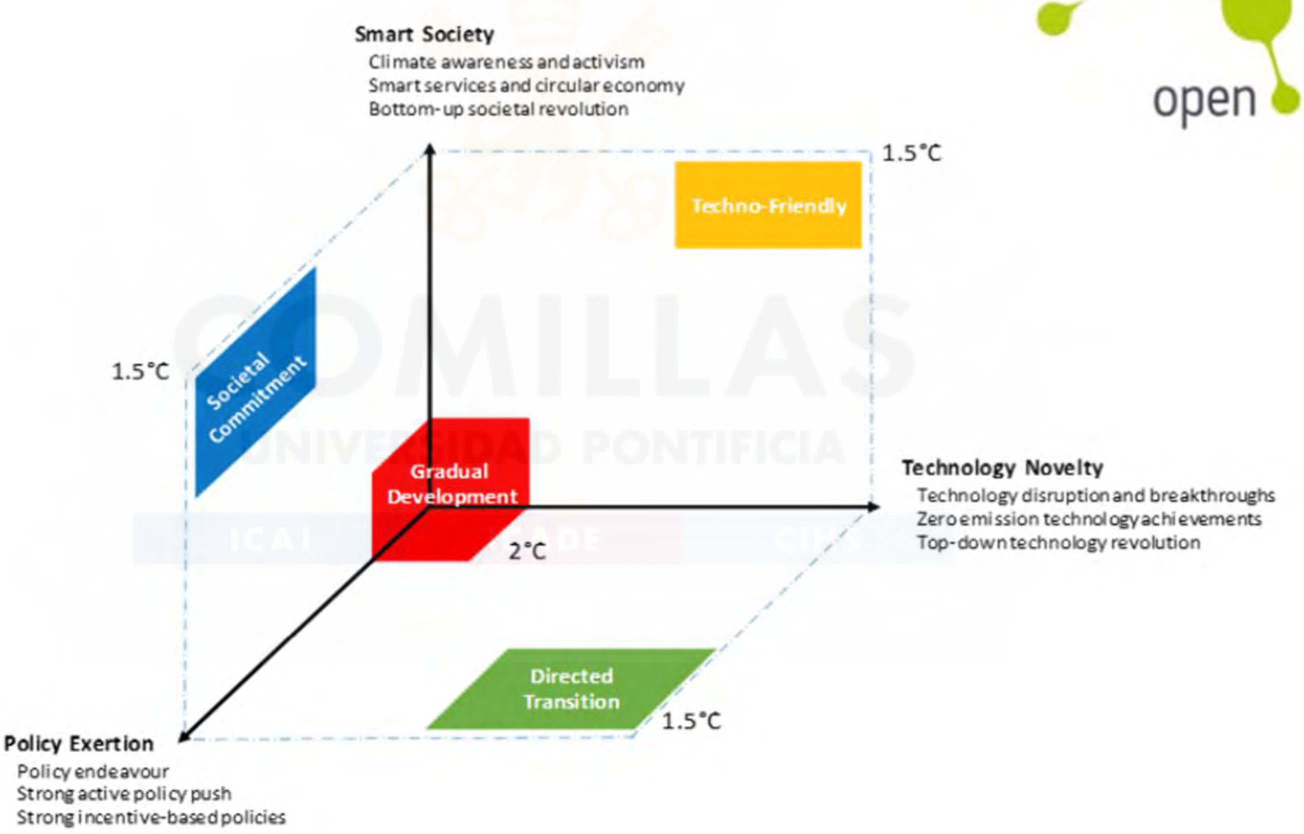
Indifferent public attitude
Low environmental focus in population and business.
Higher energy consumption and no demand
for environmentally friendly products or services

Source: SUSPLAN (http://www.susplan.eu/) Planning for Sustainability

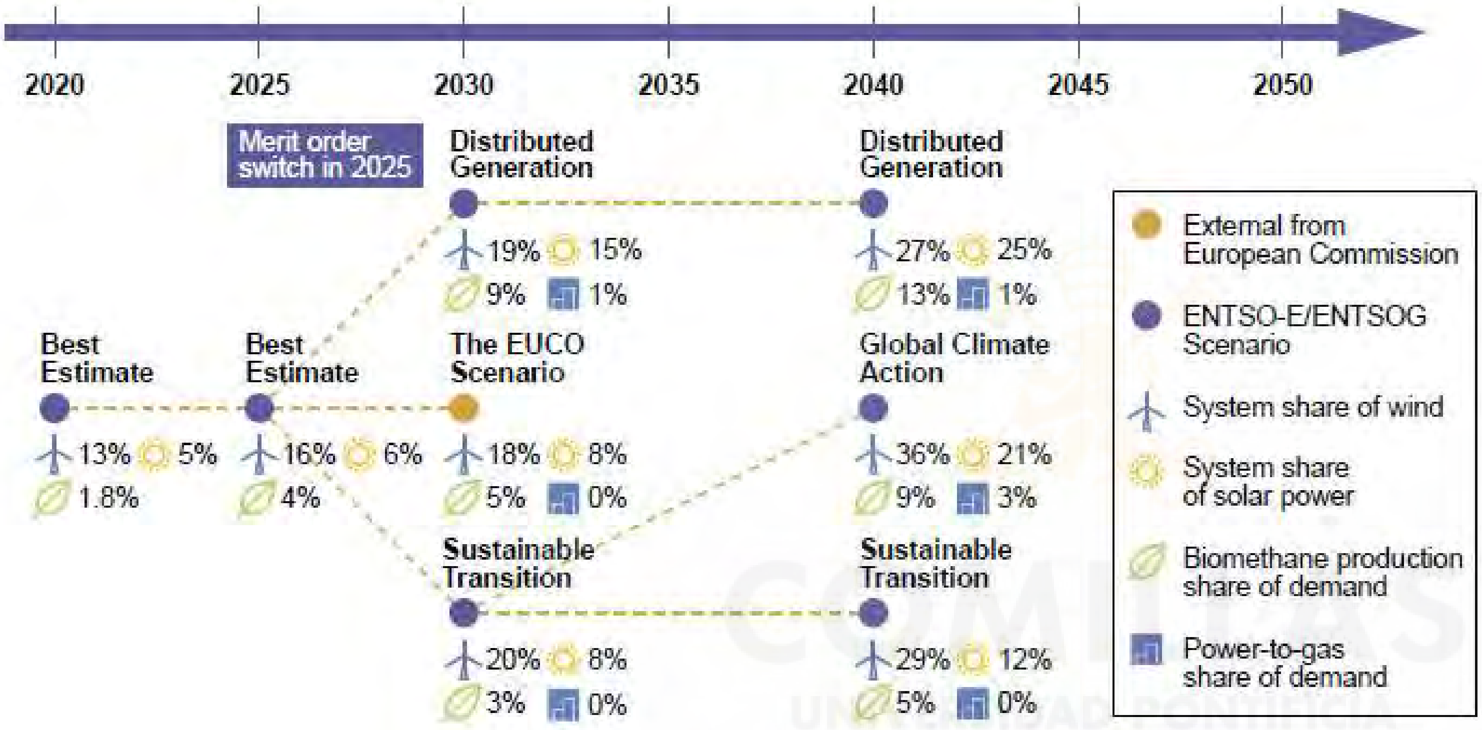
Future storylines for SET-Nav project (http://www.set-nav.eu/)

Future storylines for openENTRANCE project (https://openentrance.eu/)

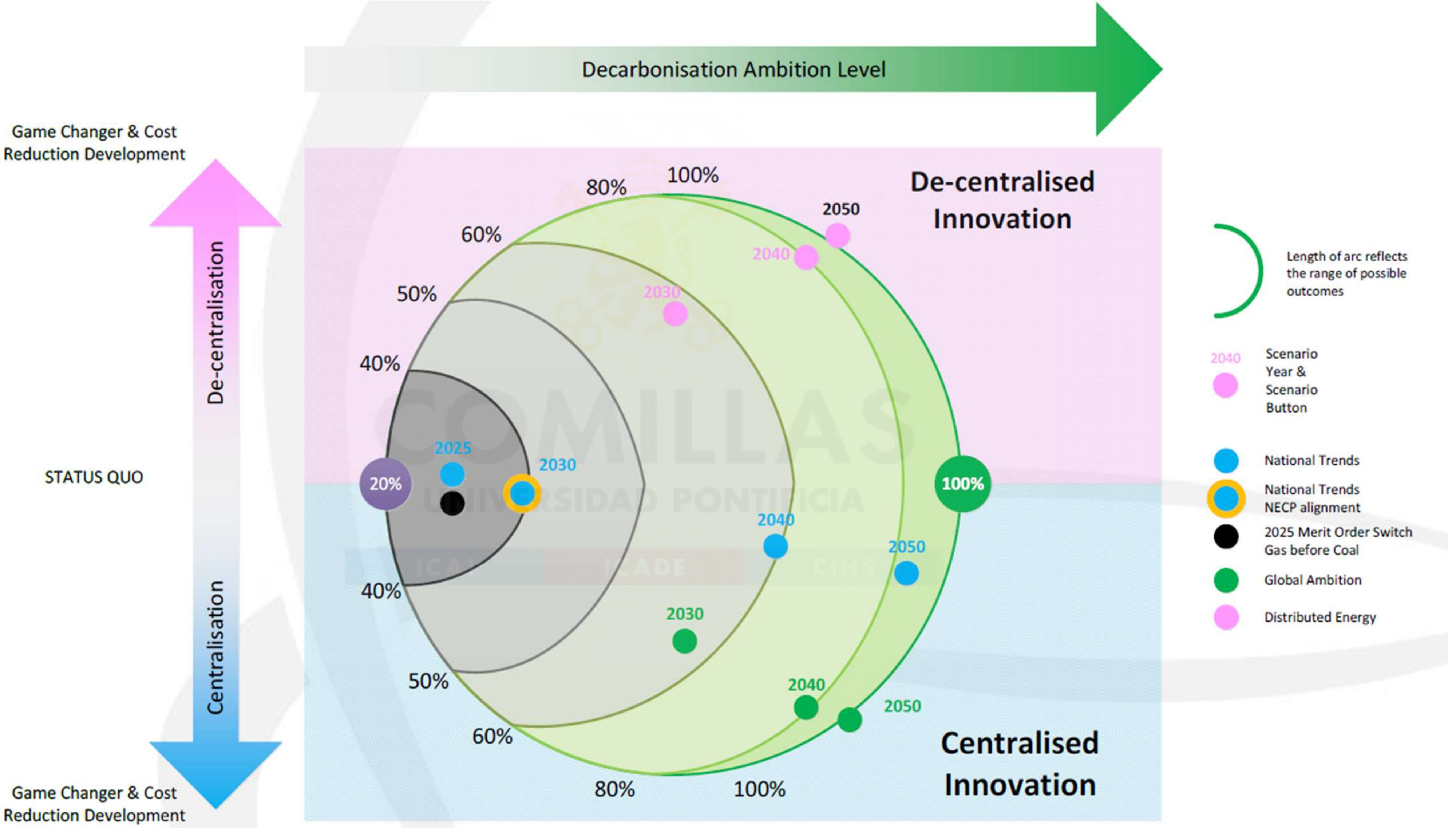
openENTRANCE Storylines



Future storylines for TYNDP 2018



TYNDP. Scenario Report



https://www.entsos-tyndp2020-scenarios.eu/#download

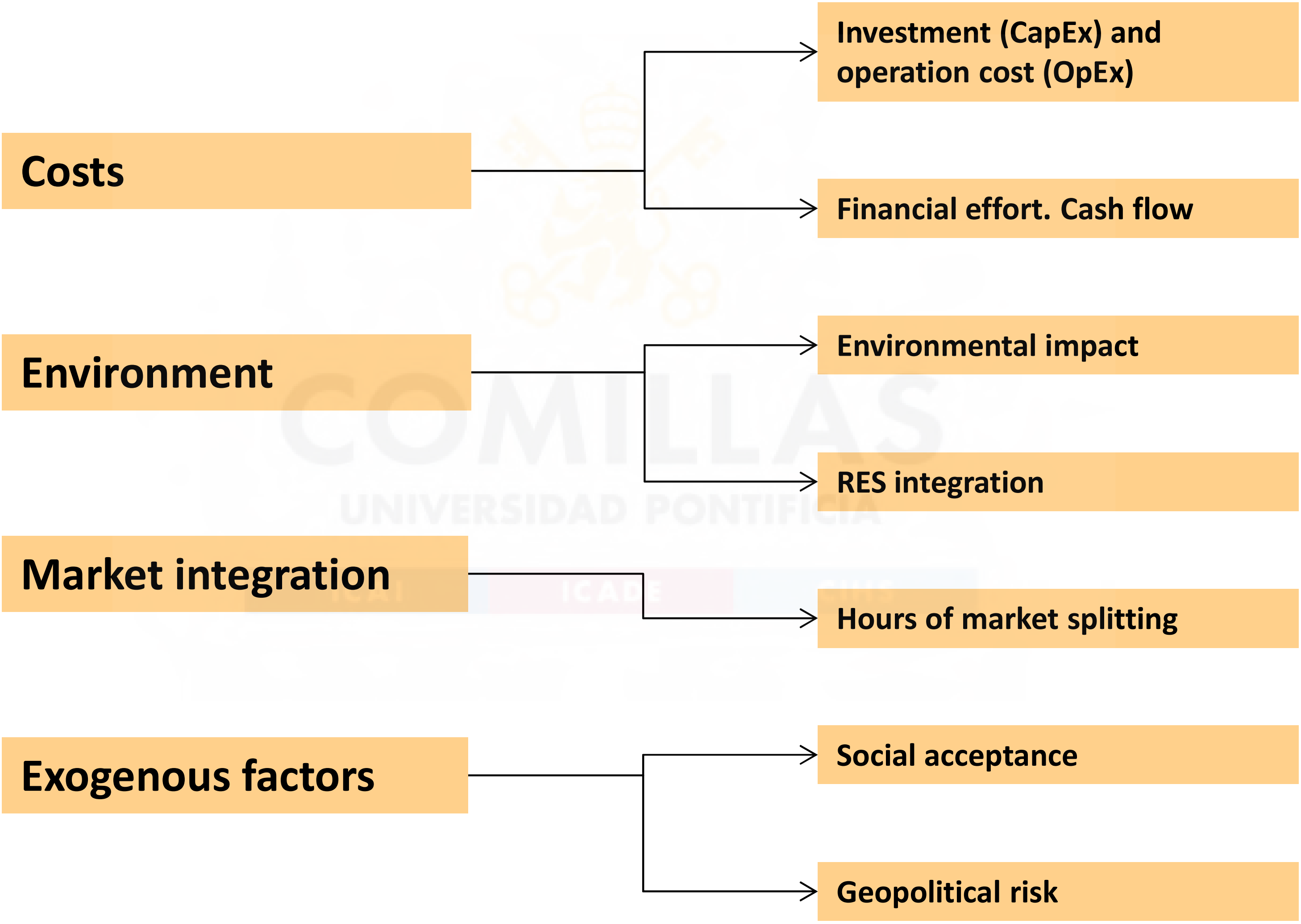
Scenarios of uncertainty

- Long-term (some of them are non-random –nonrepeatable–)
  - 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

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 the energy efficiency of the system

Multicriteria Decision Making (MCDM)



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

- Can run, although less than the cheetah

- Can fly, although less than the peregrine falcon

- Can swim, although less than the sailfish

Weighted-Sum Method of MCDM

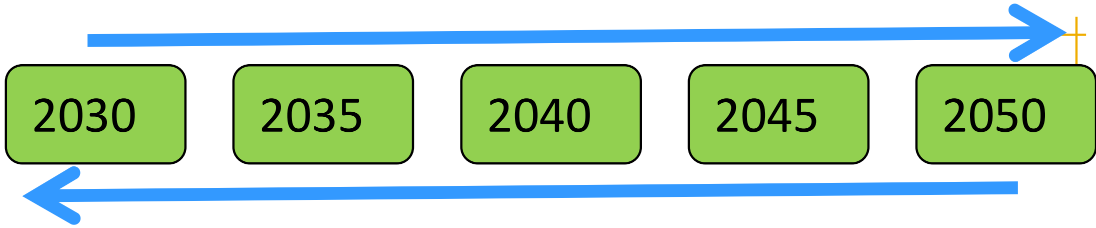
- Combines several quantifiable criteria in a single one by monetizing the criteria

$$min \sum_i \lambda_i z_i(x)$$

  - λ_i the weight of each criterion and z_i the value of the criterion

  - Reliability: not served is 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 with RES curtailment/spillage [€/MWh]
  - Environmental impact: length of the line [km] multiplied by the restoration measures to be taken [€/km]
- No quantifiable criteria are usually analyzed as a post-process for the best decisions under the previous method

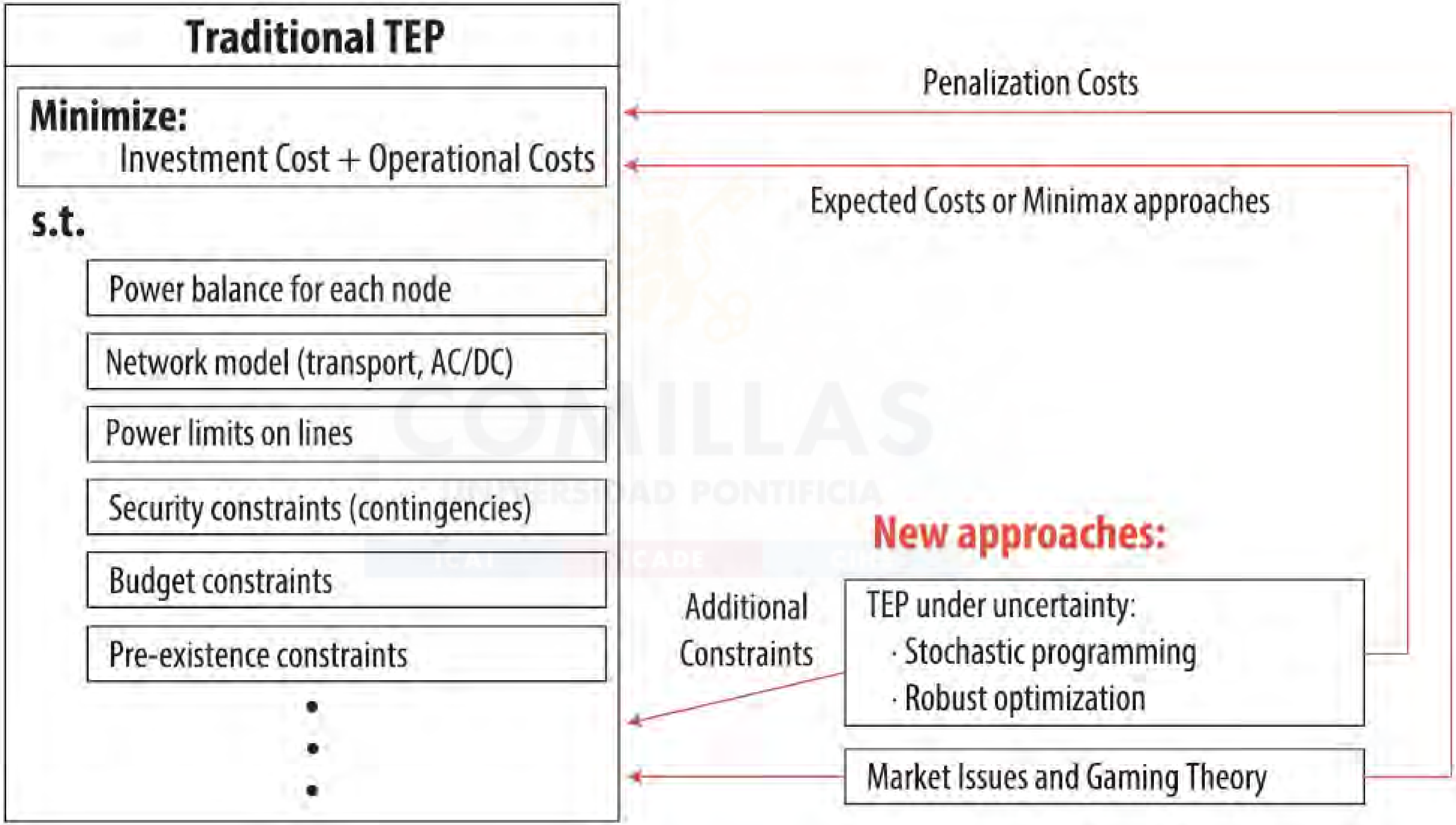
Time scope



Decision dynamics

- Static (myopic or short-sighted)
  - Determine optimal investment decisions for a horizon (the year 2030) without representing how to achieve this optimal solution from now on
  - Can be helpful as an “ideal” reference for very long-time horizons
- Sequential static (forward vs. backward planning)
- Dynamic
  - Determine optimal investment decisions since nowadays, up to a particular horizon
  - More cumbersome to solve

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

Additional Constraints

New approaches:

TEP under uncertainty:
· Stochastic programming
· Robust optimization

Market Issues and Gaming Theory

L. Gacitua, P. Gallegos, R. Henriquez-Auba, Á. Lorca, M. Negrete-Pincetic, D. Olivares, A. Valenzuela, G. Wenzel *A comprehensive review on expansion planning: Models and tools for energy policy analysis* Renewable and Sustainable Energy Reviews 98 (2018) 346–360

Other uses of transmission planning models

- Remuneration based on the 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

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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

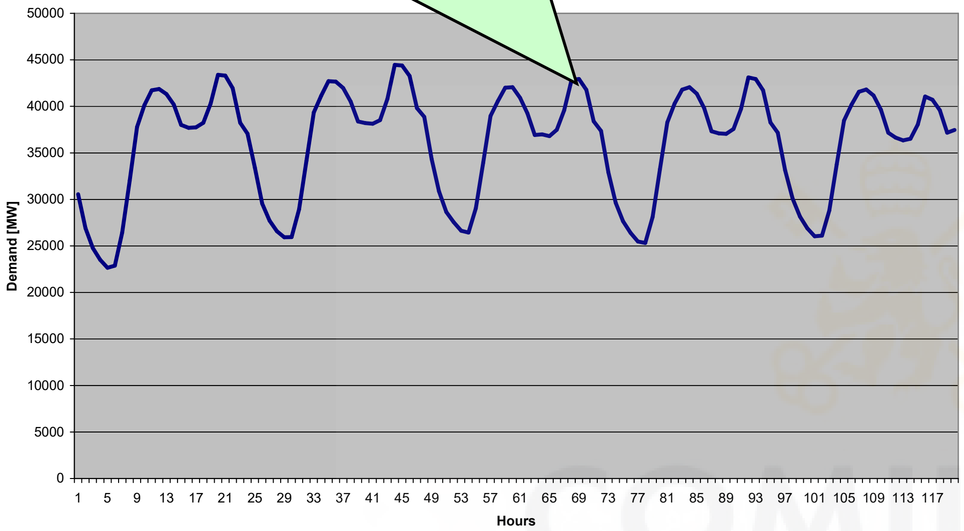
Indices

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

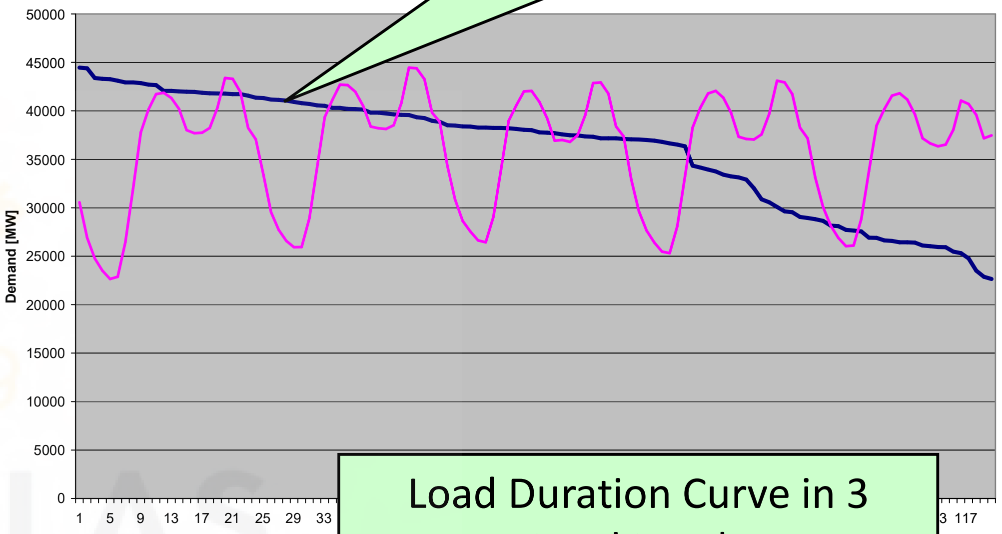
Year	y
Period	p
Subperiod	s
Load level	n
Node	d

Demand (5 weekdays)

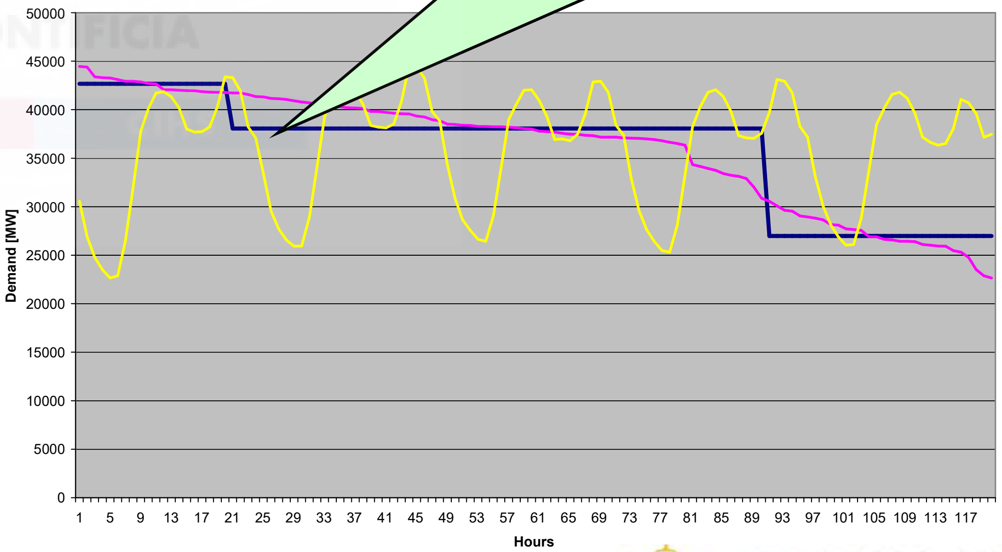
Chronological Load Curve



Load Duration Curve



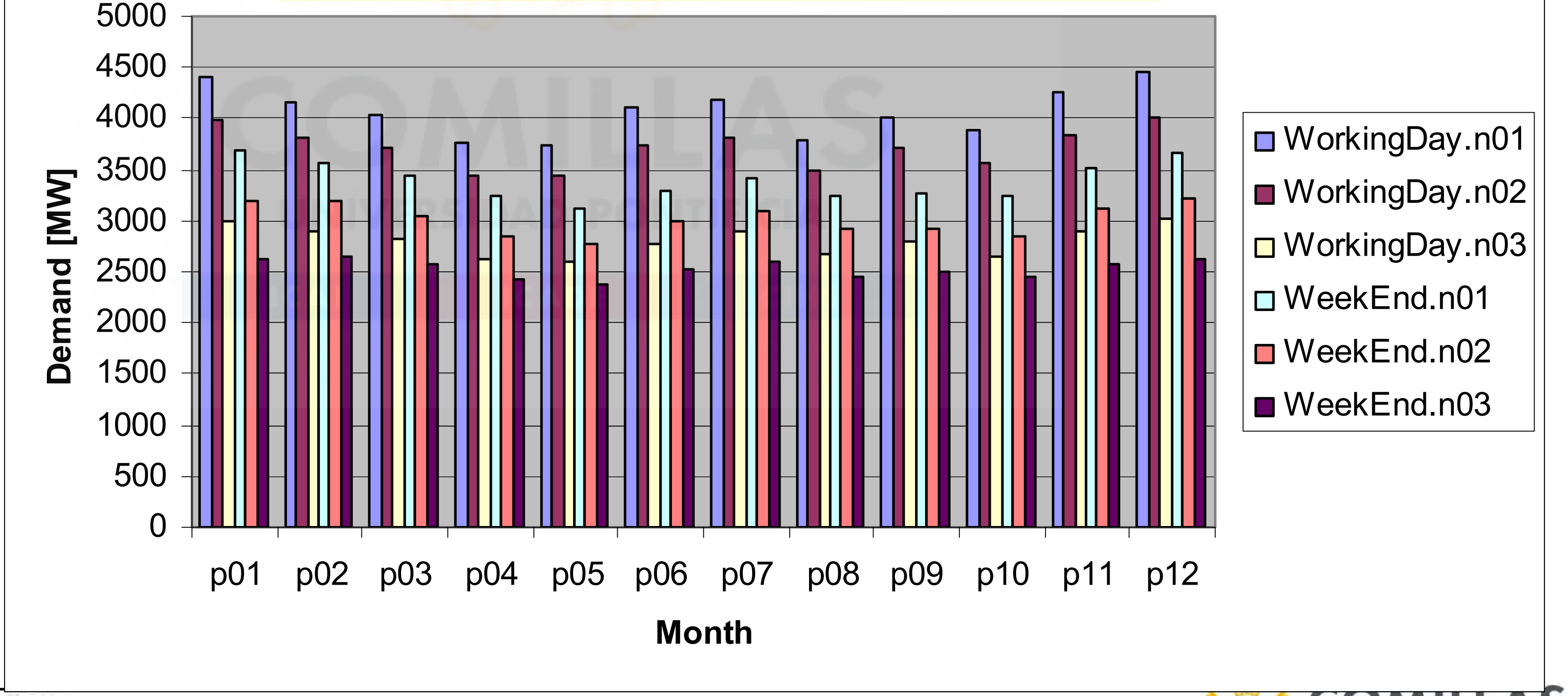
Load Duration Curve in 3 Load Levels



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)

Demand for each node	[MW]	D_{psnd}
Duration	[h]	d_{psn}
Cumm. yearly demand growth	[p.u.]	I_y



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)

Max and min output	[MW]	$\overline{p}_t, \underline{p}_t$
No load cost	[€/h]	f_t
Variable cost	[€/MWh]	v_t
Startup, shutdown cost	[€]	su_t, sd_t
EFOR	[p.u.]	q_t

Technical characteristics of hydro plants (h)

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

$Max\ and\ min\ output$	$[MW]$	$\overline{p}_h, \underline{p}_h$
$Production\ function$	$[kWh/m^3]$	c_h
$Efficiency$	$[p.u.]$	η_h

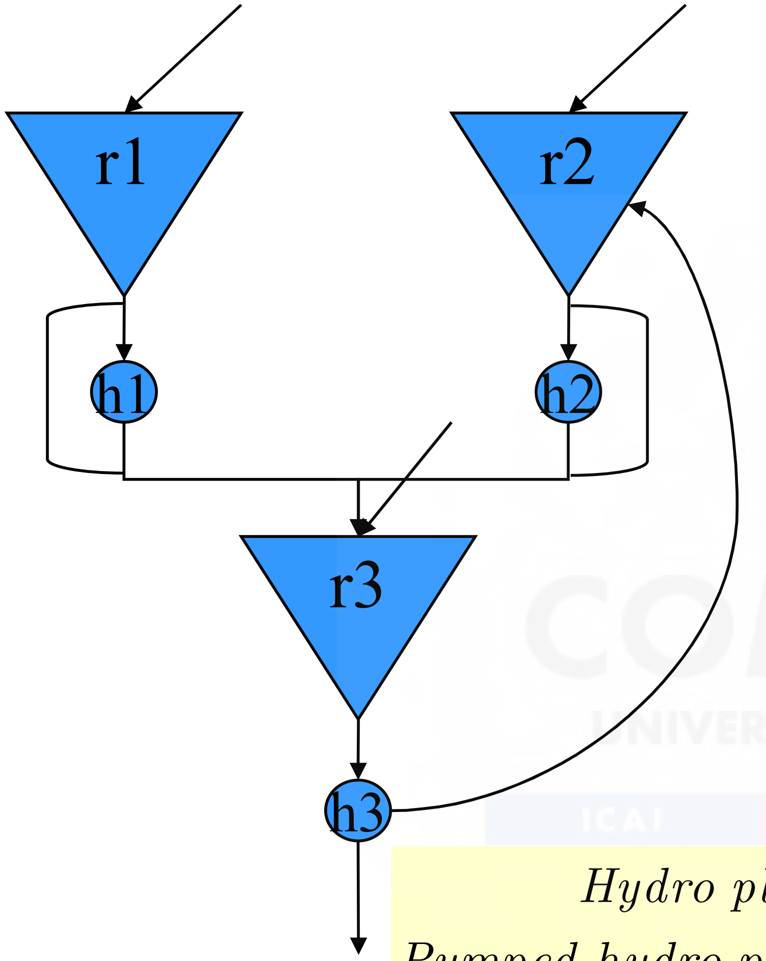
Technical characteristics of hydro reservoirs (r)

- 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

Max and min reserve	$[hm^3]$	$\overline{r}_r, \underline{r}_r$
Initial and final reserve	$[hm^3]$	r'_r
Stochastic inflows	$[m^3/s]$	i^{ω}_{pr}

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	$r' \in up(r)$	$rur(r,r)$	$(r1,r3)$

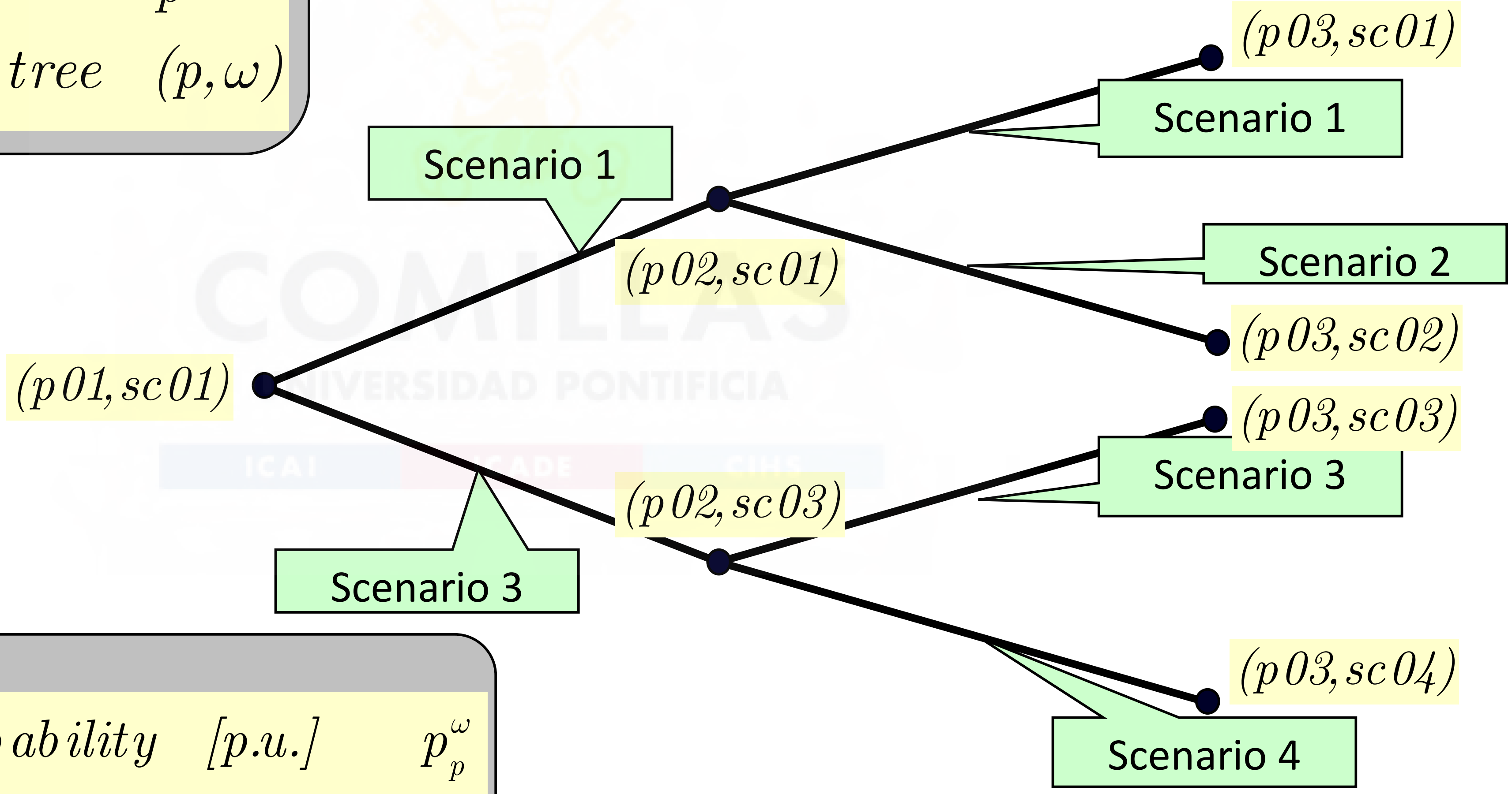
Scenario tree. Ancestor and descendant

Tree structure

Scenario	ω
Period	p
Scenario tree	(p,ω)

Tree relations

$\omega' \in a(\omega) \quad (p02, sc03) \in a\left[(p03, sc03)\right]$



Tree data

Scenario probability	[p.u.]	p_p^ω
Stochastic inflows	$[m^3/s]$	i_{pr}^ω

Technical characteristics of transmission lines (dd')

- Resistance
- Reactance
- Maximum flow

$Resistance$	$[p.u.]$	$R_{dd'}$
$Reactance$	$[p.u.]$	$X_{dd'}$
$Maximum\ flow$	$[MW]$	$\overline{F}_{dd'}$

Technical characteristics of transmission lines (dd')

- Overnight investment cost
- Fixed charge rate
  - – Annual investment cost = Overnight investment cost x Fixed charge rate

$$Annual\ investment\ cost \quad [€] \quad f'_{dd'}$$

Other system parameters

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

Energy not served cost	[€ / MWh]	v'
Power not served cost	[€ / MW]	v''
Operating reserve	[MW]	O_{ps1}
Base power	[MW]	S_B

Investment variables

- Transmission line exists in year y

$$Candidate\ line\ exists\ in\ year\ y \quad \{0,1\} \quad IC_{ydd'}$$

Operation variables for each year

- Commitment, startup, and shutdown of thermal units

$$Commitment,\ startup\ and\ shutdown\quad \{0,1\}\quad UC^{\omega}_{ypst}, SU^{\omega}_{ypst}, SD^{\omega}_{ypst}$$

- Production of thermal and hydro units

$$Production\ of\ a\ thermal\ or\ hydro\ unit\quad [MW]\quad P^{\omega}_{ypsnt}, P^{\omega}_{ypsnh}$$

- Consumption of pumped storage hydro plants

$$Consumption\ of\ a\ hydro\ plant\quad [MW]\quad C^{\omega}_{ypsnh}$$

- Reservoir levels

$$Reservoir\ level\quad [hm^{3}]\quad R^{\omega}_{ypr}$$

- Energy not served for each node, and power not served

$$Energy\ and\ power\ not\ served\quad [MW]\quad ENS^{\omega}_{ypsnd}, PNS^{\omega}_{yps}$$

Operation variables for each year

- Flow for the transmission lines

$$Flow \quad [MW] \quad F^{\omega}_{ypsndd'}$$

- Voltage angle in any node

$$Voltage\ angle \quad [rad] \quad \theta^{\omega}_{ypsnd}$$

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* [*MW*]

$$\sum_t \overline{p}_t UC^{\omega}_{ypst} + \sum_h \overline{p}_h + PNS^{\omega}_{yps} \geq (D_{ps1} + O_{ps1}) I_y \quad \forall \omega yps$$

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*

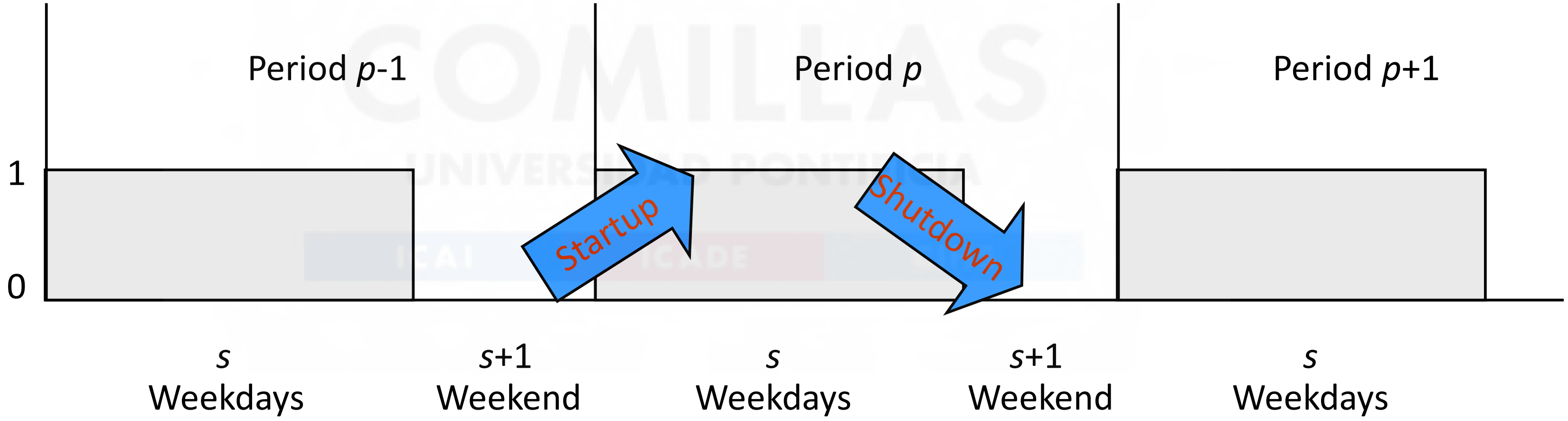
= *Demand* *for each node, load level, subperiod, period, year and scenario* [MW]

$$\sum_{t\in d} P^{\omega}_{ypsnt} + \sum_{h\in d} P^{\omega}_{ypsnh} - \sum_{h\in d} C^{\omega}_{ypsnh} + ENS^{\omega}_{ypsnd} + \sum_{d'} F^{\omega}_{ypsnd'd} - \sum_{d'} F^{\omega}_{ypsndd'} = D_{psnd} I_{y} \qquad \forall \omega ypsnd$$

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 [*p.u.*]

$$UC^{\omega}_{ypst} - UC^{\omega'}_{yp-1s+1t} = SU^{\omega}_{ypst} - SD^{\omega}_{ypst} \quad \forall \omega ypst \quad \omega' \in a(\omega)$$

- 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 [*p.u.*]

$$UC^{\omega}_{yps+1t} - UC^{\omega}_{ypst} = SU^{\omega}_{yps+1t} - SD^{\omega}_{yps+1t} \quad \forall \omega ypst$$

Constraints: Commitment and production

Production of a thermal unit

≥ Commitment of a thermal unit times the minimum output reduced by availability rate [*MW*]

Production of a thermal unit

≤ Commitment of a thermal unit times the maximum output reduced by availability rate [*MW*]

$$UC^{\omega}_{ypst}\underline{p}_t(1-q_t) \le P^{\omega}_{ypsnt} \le UC^{\omega}_{ypst}\overline{p}_t(1-q_t) \quad \forall \omega ypsnt$$

- If the thermal unit is committed ($UC^{\omega}_{ypst} = 1$) it can produce between its minimum and maximum output
- If the thermal unit is not committed ($UC^{\omega}_{ypst} = 0$) 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* [*hm*^{3}]

$$
\begin{aligned}
&R^{\omega'}_{yp-1r} - R^{\omega}_{ypr} + i^{\omega}_{pr} - S^{\omega}_{ypr} + \sum_{r'\in up(r)} S^{\omega}_{ypr'} \\
&+ \sum_{\substack{sn\\ h\in up(r)}} d_{psn} P^{\omega}_{ypsnh} / c_h - \sum_{\substack{sn\\ h\in dw(r)}} d_{psn} P^{\omega}_{ypsnh} / c_h \\
&+ \sum_{\substack{sn\\ h\in up(r)}} d_{psn} C^{\omega}_{ypsnh} \eta_h / c_h - \sum_{\substack{sn\\ h\in dw(r)}} d_{psn} C^{\omega}_{ypsnh} \eta_h / c_h = 0 \qquad \forall \omega ypr \quad \omega' \in a(\omega)
\end{aligned}
$$

Constraints: Operation limits

Reservoir volumes between limits for each hydro reservoir [*hm*^{3}]

$$\underline{r}_r \leq R^{\omega}_{ypr} \leq \overline{r}_r \qquad \forall \omega y p r$$

$$R_{0r} = R^{\omega}_{yPr} = r'_r \quad \forall \omega y r$$

Operation power lower than installed capacity [*MW*]

$$0 \leq P^{\omega}_{ypsnt} \leq \overline{p}_t (1 - q_t) \quad \forall \omega y p s n t$$

$$0 \leq P^{\omega}_{ypsnh}, C^{\omega}_{ypsnh} \leq \overline{p}_h \quad \forall \omega y p s n h$$

Commitment, startup and shutdown for each unit [*MW*]

$$UC^{\omega}_{ypst}, SU^{\omega}_{ypst}, SD^{\omega}_{ypst} \in \left\{0, 1\right\} \quad \forall \omega y p s t$$

Constraints: DC linearized load flow and flow limits

Flow in existing lines as a function of the voltage angles of beginning and ending nodes [MW]

$$F^{\omega}_{ypsndd'} = \frac{\theta^{\omega}_{ypsnd} - \theta^{\omega}_{ypsnd'}}{X_{dd'}} S_B \quad \forall \omega ypsndd'$$

Flow in candidate lines as a function of the voltage angles of beginning and ending nodes [MW]

$$F^{\omega}_{ypsndd'} \le \frac{\theta^{\omega}_{ypsnd} - \theta^{\omega}_{ypsnd'}}{X_{dd'}} S_B + \overline{F}'_{dd'}(1 - IC_{ydd'}) \quad \forall \omega ypsndd'$$

$$F^{\omega}_{ypsndd'} \ge \frac{\theta^{\omega}_{ypsnd} - \theta^{\omega}_{ypsnd'}}{X_{dd'}} S_B - \overline{F}'_{dd'}(1 - IC_{ydd'}) \quad \forall \omega ypsndd'$$

Constraints: Flow limits and voltage angle

Flow of existing lines below limit for every year [*MW*]

$$-\overline{F}_{dd'} \leq F^{\omega}_{ypsndd'} \leq \overline{F}_{dd'} \quad \forall \omega ypsndd'$$

Flow of candidate lines below limit for every year [*MW*]

$$-\overline{F}_{dd'} IC_{ydd'} \leq F^{\omega}_{ypsndd'} \leq \overline{F}_{dd'} IC_{ydd'} \quad \forall \omega ypsndd$$

Reference angle [*rad*]

$$\theta^{\omega}_{ypsnd*} = 0 \quad \forall \omega ypsn$$

Constraints: Installation decision in consecutive years

Existence of an installed line in the following year [*p.u.*]

$$IC_{y-1dd'} \leq IC_{ydd'} \quad \forall ydd'$$

Weighted-sum objective function

- Minimize
  - Transmission investment costs [€]

$$\sum_{y}\sum_{dd'} f'_{dd'} IC_{ydd'}$$

  - Thermal unit expected variable (fuel, O&M, emission) costs [€]

$$\sum_{y\omega pst} p_p^\omega su_t SU_{ypst}^\omega + \sum_{y\omega pst} p_p^\omega sd_t SD_{ypst}^\omega + \sum_{y\omega psnt} p_p^\omega d_{psn} f_t UC_{ypst}^\omega + \sum_{y\omega psnt} p_p^\omega d_{psn} v_t P_{ypsnt}^\omega$$

  - Expected penalties introduced in the objective function for energy not served and power non served [€]

$$\sum_{y\omega psnd} p_p^\omega d_{psn} v' ENS_{ypsnd}^\omega + \sum_{y\omega ps} p_p^\omega v'' PNS_{yps}^\omega$$

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 increase in the demand when binary variables (investment, commitment, startup, and shutdown) are relaxed (LRMC) or binary/fixed (SRMC)

$$\sum_{t \in d} P^{\omega}_{ypsnt} + \sum_{h \in d} P^{\omega}_{ypsnh} - \sum_{h \in d} C^{\omega}_{ypsnh} + ENS^{\omega}_{ypsnd} + \sum_{d'} F^{\omega}_{ypsnd'd} - \sum_{d'} F^{\omega}_{ypsndd'} = D_{psnd} I_{y} \quad : \sigma^{\omega}_{ypsnd} \qquad \forall \omega ypsnd$$

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

$$LRMC \;\; or \; SRMC^{\omega}_{ypsnd} = \sigma^{\omega}_{ypsnd} \,/\, d_{psn} \,/\, p^{\omega}_{p} \qquad \forall \omega ypsnd$$

1. Transmission Expansion Planning
2. Simple TEP models
3. Modeling issues
4. Prototype TEP. Mathematical formulation
5. Prototype TEP. Computer implementation
6. Takeaways

5

Prototype TEP.

Computer implementation

openTEPES Open Generation, Storage, and Transmission Operation and Expansion Planning Model with RES and ESS in Pyomo

(https://pascua.iit.comillas.edu/aramos/openTEPES/index.html) (https://github.com/IIT-EnergySystemModels/openTEPES)

openTEPES

version 4.14.7

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Open Generation, Storage, and **T**ransmission Operation and **E**xpansion **P**lanning Model with RES and **ESS** (**openTEPES**)

"Simplicity and Transparency in Energy Systems Planning"

The **openTEPES** model has been developed at the Instituto de Investigación Tecnológica (IIT) of the Universidad Pontificia Comillas.

It is integrated into the open energy system modelling platform, helping model Europe's energy system.

It has been used by the **Ministry for the Ecological Transition and the Demographic Challenge (MITECO)** to analyze the electricity sector in the latest Spanish National Energy and Climate Plan (NECP) 2023-2030 in June 2023.

Reference: A. Ramos, E. Quispe, S. Lumbreras "OpenTEPES: Open-source Transmission and Generation Expansion Planning" SoftwareX 18: June 2022 10.1016/j.softx.2022.101070

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    - Variable maximum and minimum generation
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    - Variable maximum and minimum storage
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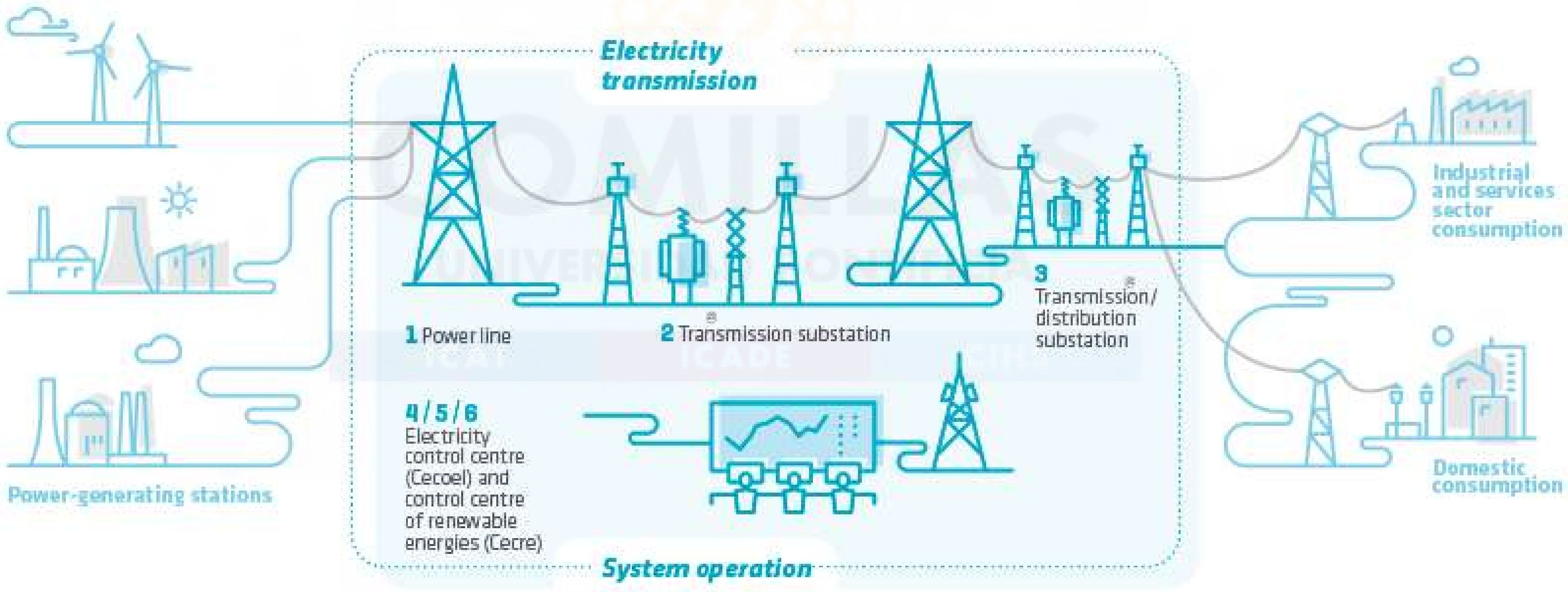
Main modeling features (i)

- Generation and transmission operation and expansion planning
- Network-constrained unit commitment (NCUC)
- DC power flow (DCPF) with losses
- Hourly, bi-hourly, etc. time steps

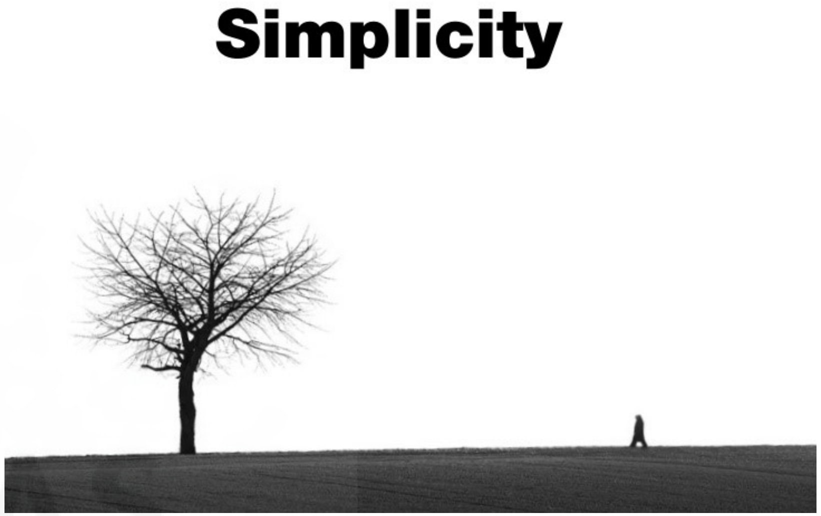


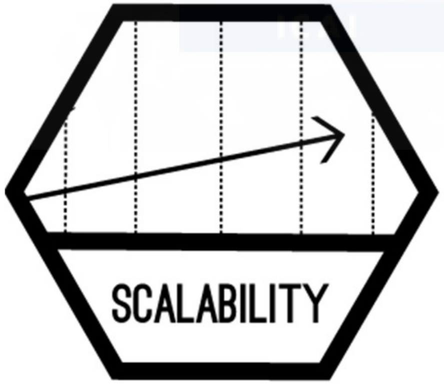
Main modeling features (ii)

- Energy Storage Systems (ESS), e.g., hydropower plants, open- and closed-loop pumped-storage hydro, battery
- Pumped-storage hydro (PSH) or batteries operate shifting energy between different timeframes and represent a small modification of the operation variable cost → a detailed system operation modeling is mandatory
  - Hourly operation
  - Unit-based modeling of energy storage units

Main code features

- Simplicity and transparency
- Code is written to be read by humans
- Tight and compact formulation
- Careful implementation. Numerical stability
- Scalability: from small- to large-scale cases





Sets

ω	Scenario
p	Period
n	Load level
ν	Time step. Duration of each load level (e.g., 2 h, 3 h)
g	Generator (thermal or hydro unit or ESS)
t	Thermal unit
e	Energy Storage System (ESS)
i, j	Node
z	Zone. Each node belongs to a zone $i \in z$
a	Area. Each zone belongs to an area $z \in a$
r	Region. Each area belongs to a region $a \in r$
c	Circuit
ijc	Line (initial node, final node, circuit)
EG, CG	Set of existing and candidate generators
EE, CE	Set of existing and candidate ESS
EL, CL	Set of existing and candidate lines

Demand and operating reserves

- Balance of generation and demand [GW]
- Upward and downward operating reserves [GW] provided by controllable generators (CCGT, storage hydro) and ESS (pumped-storage hydro, batteries), including activation of these reserves [GWh]
- Reserve activation: a proportion (e.g., 25-30 %) of the power provided as operating reserves that are asked to be deployed as energy

Parameters. Demand and operating reserves

They are written in capital letters.

Demand		
$D_{\omega pni}$	Demand in each node	GW
DUR_n	Duration of each load level	h
$CENS$	Cost of energy not served. Value of Lost Load (VoLL)	€/MWh

Scenarios		
P_ω	Probability of each scenario	p.u.

Operating reserves		
URA, DRA	Upward and downward reserve activation	p.u.
$UR_{\omega pna}, DR_{\omega pna}$	Upward and downward operating reserves for each area	GW

Thermal subsystem

- Maximum and minimum output of the second block of a committed unit (all except the VRES units) [p.u.]
- Total output of a committed unit [GW]
- Logical relation between commitment, startup, and shutdown status of a committed unit [p.u.]
- Maximum ramp up and down for the second block of a thermal unit [p.u.]
- Minimum up time and down time of a thermal unit [h]

Hydro and storage subsystems

- Power plants: hydro, open-loop pumped-storage hydro (PSH) aggregated in management units, closed-loop PSH treated individually, and system battery storage
- ESS energy inventory (only for load levels multiple of 24 or 168 h depending on the ESS type) [TWh]
- Total charge of an ESS unit [GW]
- Maximum and minimum charge of an ESS [p.u.]
- Incompatibility between charge and discharge of an ESS [p.u.]

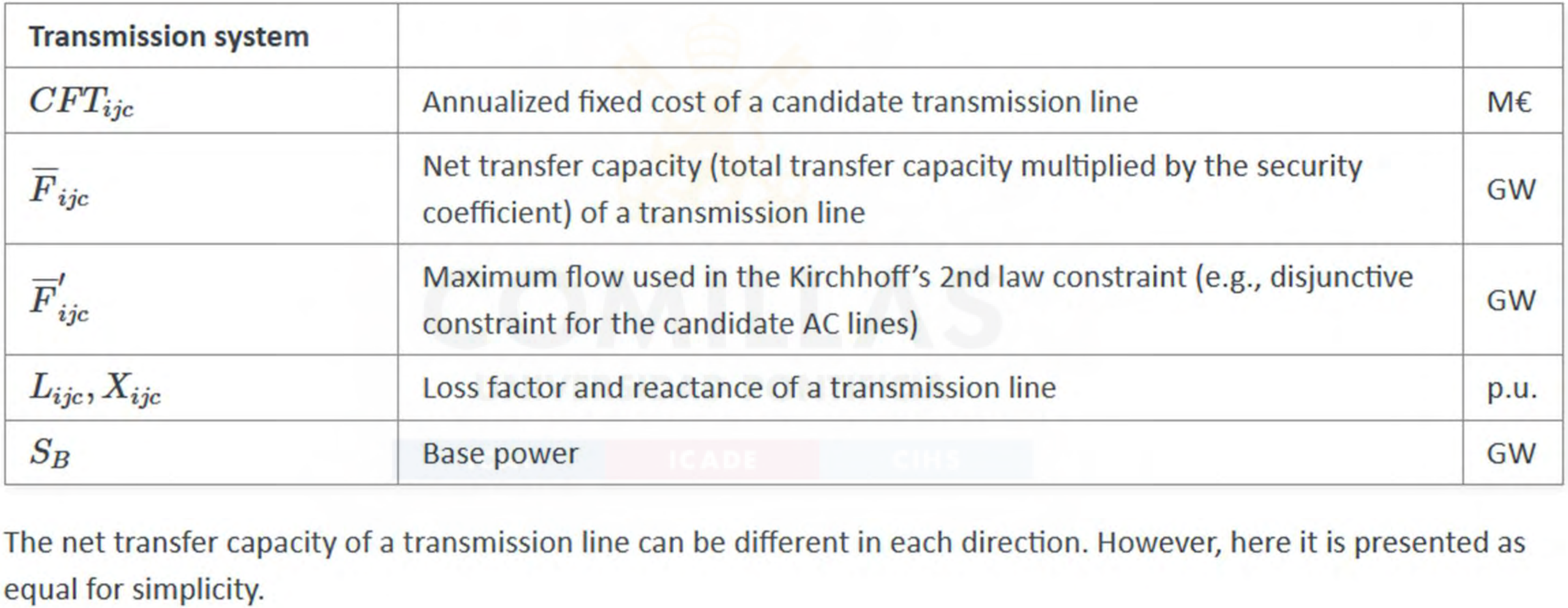
Variable renewable energy sources (VRES)

- Power plants: solar PV, solar thermal, onshore wind, biomass
- Distinction between existing onshore wind and a new one
- Maximum and minimum hourly variable generation

Parameters. Generation

Generation system		
CFG_g	Annualized fixed cost of a candidate generator	M€
$\underline{GP}_g, \overline{GP}_g$	Minimum load and maximum output of a generator	GW
$\overline{GC}_e$	Maximum consumption of an ESS	GW
CF_g, CV_g	Fixed and variable cost of a generator. Variable cost includes fuel, O&M and emission cost	€/h, €/MWh
CV_e	Variable cost of an ESS when charging	€/MWh
RU_t, RD_t	Ramp up and ramp down of a thermal unit	MW/h
TU_t, TD_t	Minimum uptime and downtime of a thermal unit	h
CSU_g, CSD_g	Startup and shutdown cost of a committed unit	M€
τ_e	Characteristic duration of the ESS (e.g., 24 h, 168 h, 672 h -for daily, weekly, monthly-)	h
EF_e	Efficiency of the pump/turbine cycle of a hydro power plant or charge/discharge of a battery	p.u.
I_e	Capacity of an ESS (e.g., hydro power plant)	GWh
EI_{wpng}	Energy inflows of an ESS (e.g., hydro power plant)	GWh

Parameters. Transmission network



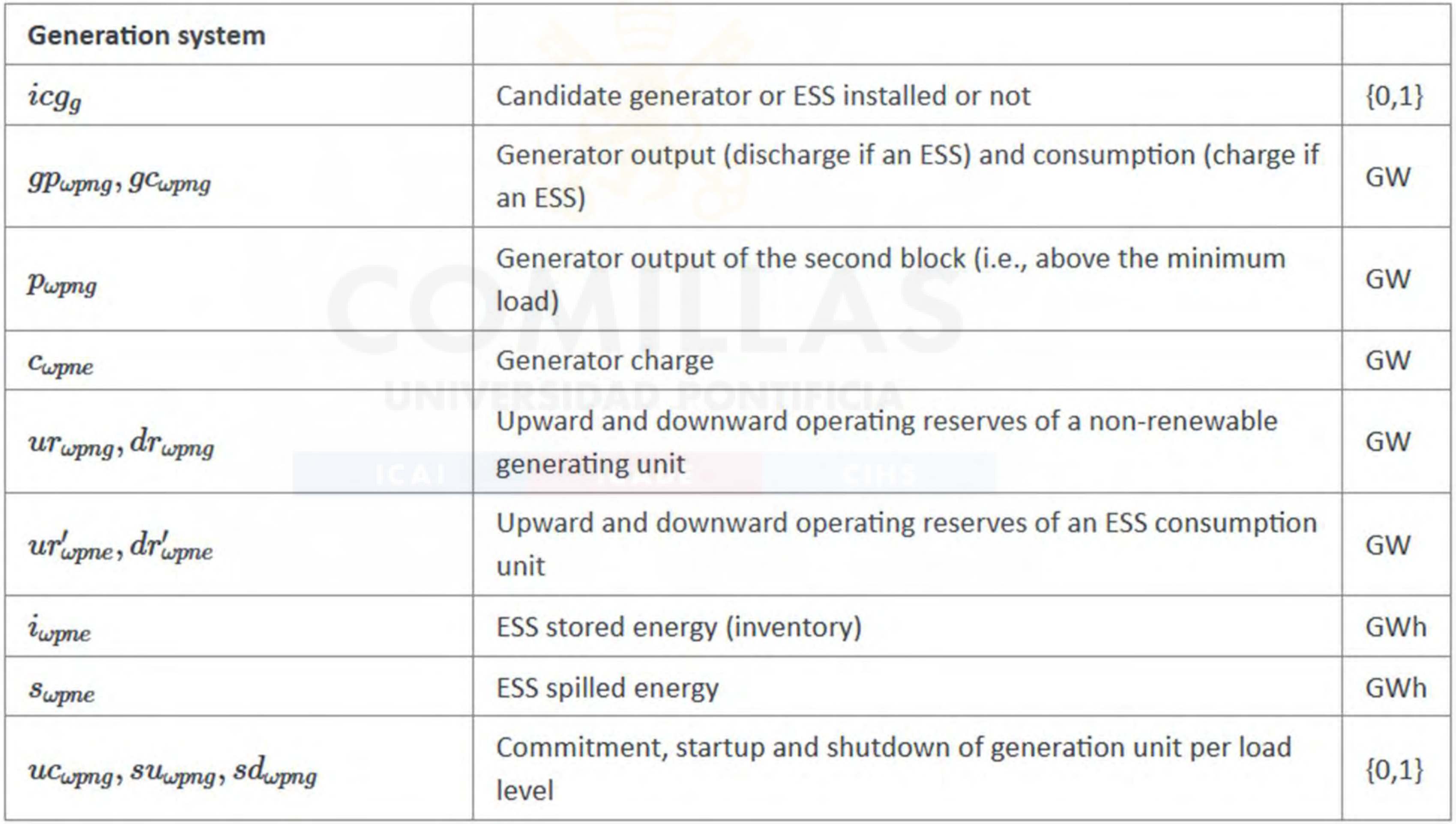
Transmission system		
CFT_{ijc}	Annualized fixed cost of a candidate transmission line	M€
$\overline{F}_{ijc}$	Net transfer capacity (total transfer capacity multiplied by the security coefficient) of a transmission line	GW
$\overline{F}'_{ijc}$	Maximum flow used in the Kirchhoff's 2nd law constraint (e.g., disjunctive constraint for the candidate AC lines)	GW
L_{ijc}, X_{ijc}	Loss factor and reactance of a transmission line	p.u.
S_B	Base power	GW

The net transfer capacity of a transmission line can be different in each direction. However, here it is presented as equal for simplicity.

Variables. ENS and generation

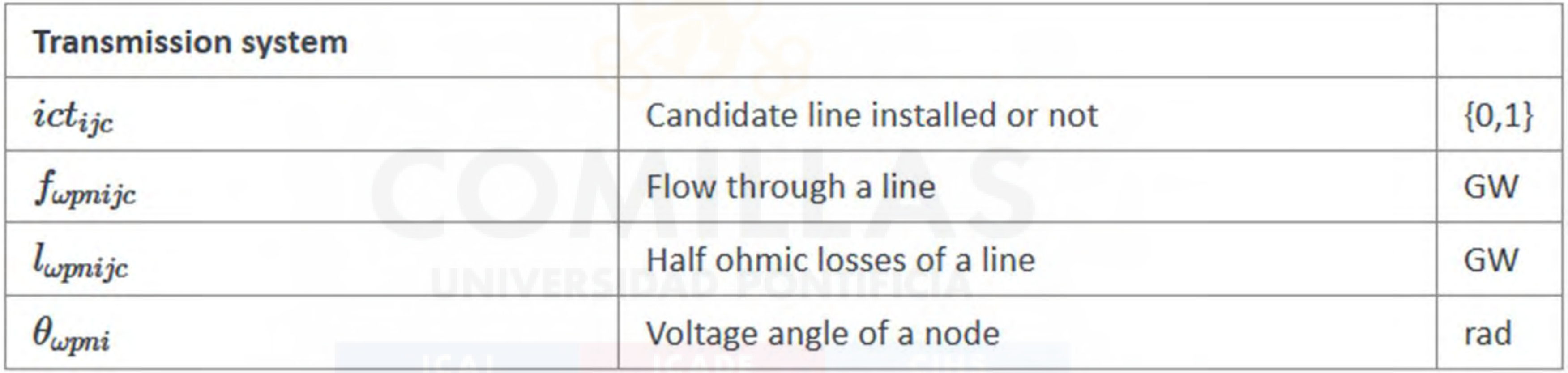
They are written in lower letters.

Demand		
$ens_{\omega pni}$	Energy not served	GW



Generation system		
icg_g	Candidate generator or ESS installed or not	{0,1}
$gp_{\omega png}, gc_{\omega png}$	Generator output (discharge if an ESS) and consumption (charge if an ESS)	GW
$p_{\omega png}$	Generator output of the second block (i.e., above the minimum load)	GW
$c_{\omega pne}$	Generator charge	GW
$ur_{\omega png}, dr_{\omega png}$	Upward and downward operating reserves of a non-renewable generating unit	GW
$ur'_{\omega pne}, dr'_{\omega pne}$	Upward and downward operating reserves of an ESS consumption unit	GW
$i_{\omega pne}$	ESS stored energy (inventory)	GWh
$s_{\omega pne}$	ESS spilled energy	GWh
$uc_{\omega png}, su_{\omega png}, sd_{\omega png}$	Commitment, startup and shutdown of generation unit per load level	{0,1}

Variables. Transmission network



Transmission system		
ict_{ijc}	Candidate line installed or not	{0,1}
$f_{\omega pnijc}$	Flow through a line	GW
$l_{\omega pnijc}$	Half ohmic losses of a line	GW
$\theta_{\omega pni}$	Voltage angle of a node	rad

Objective function

Objective function: minimization of total (investment and operation) cost for the scope of the model

Generation, storage and network investment cost [M€]

$$\sum_g CFG_g icg_g + \sum_{ijc} CFT_{ijc} ict_{ijc} +$$

Generation operation cost [M€]

$$\sum_{\omega png} [P_\omega DUR_n (CV_g gp_{\omega png} + CF_g uc_{\omega png}) + CSU_g su_{\omega png} + CSD_g sd_{\omega png}] +$$

Variable consumption operation cost [M€]

$$\sum_{\omega pne} [P_\omega DUR_n CV_e gc_{\omega pne}] +$$

Reliability cost [M€]

$$\sum_{\omega pni} P_\omega DUR_n CENS ens_{\omega pni}$$

Constraints. Operation bounded by investment

Commitment decision bounded by investment decision for candidate committed units (all except the VRES units) [p.u.]

$$uc_{\omega png} \leq icg_g \quad \forall \omega png, g \in CG$$

Output and consumption bounded by investment decision for candidate ESS [p.u.]

$$\frac{gp_{\omega pne}}{\overline{GP}_e} \leq icg_e \quad \forall \omega pne, e \in CE$$

$$\frac{gc_{\omega pne}}{\overline{GC}_e} \leq icg_e \quad \forall \omega pne, e \in CE$$

Constraints. Balance and operating reserves

Balance of generation and demand at each node with ohmic losses [GW]

$$\sum_{g\in i} gp_{\omega png} - \sum_{e\in i} gc_{\omega pne} + ens_{\omega pni} = D_{\omega pni} + \sum_{jc} l_{\omega pnijc} + \sum_{jc} l_{\omega pnjic} + \sum_{jc} f_{\omega pnijc} - \sum_{jc} f_{\omega pnjic} \quad \forall \omega pni$$

Upward and downward operating reserves provided by non-renewable generators, and ESS when charging for each area [GW]

$$\sum_{g\in a} ur_{\omega png} + \sum_{e\in a} ur'_{\omega pne} = UR_{\omega pna} \quad \forall \omega pna$$

$$\sum_{g\in a} dr_{\omega png} + \sum_{e\in a} dr'_{\omega pne} = DR_{\omega pna} \quad \forall \omega pna$$

VRES units (i.e., those with linear variable cost equal to 0 and no storage capacity) do not contribute to the the operating reserves.

Operating reserves from ESS can only be provided if enough energy is available for producing

$$ur_{\omega pne} \leq \frac{i_{\omega pne}}{DUR_n} \quad \forall \omega pne$$

$$dr_{\omega pne} \leq \frac{I_e - i_{\omega pne}}{DUR_n} \quad \forall \omega pne$$

or for storing

$$ur'_{\omega pne} \leq \frac{I_e - i_{\omega pne}}{DUR_n} \quad \forall \omega pne$$

$$dr'_{\omega pne} \leq \frac{i_{\omega pne}}{DUR_n} \quad \forall \omega pne$$

Constraints. ESS Inventory. Total output

ESS energy inventory (only for load levels multiple of 24, 168 or 672 h depending on the ESS type) [GWh]

$$i_{\omega p,n-\tau_e,e} + \sum_{n'=n+\nu-\tau_e}^{n} DUR_n(EI_{\omega pne} - gp_{\omega pne} + EF_e gc_{\omega pne}) = i_{\omega pne} + s_{\omega pne} \quad \forall \omega pne$$

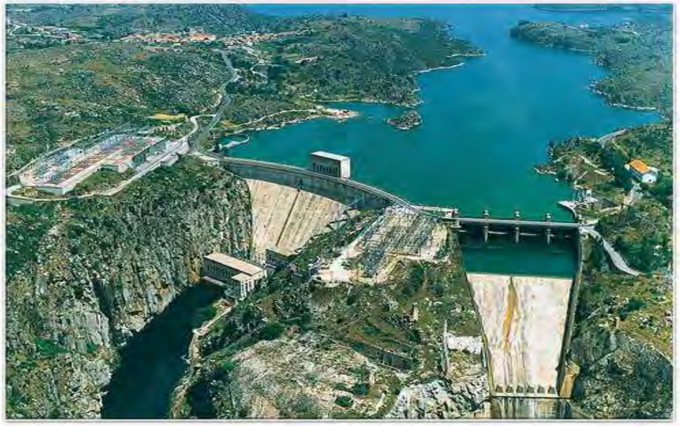
Maximum and minimum output of the second block of a committed unit (all except the VRES units) [p.u.]

- D.A. Tejada-Arango, S. Lumbreras, P. Sánchez-Martín, and A. Ramos "Which Unit-Commitment Formulation is Best? A Systematic Comparison" IEEE Transactions on Power Systems 35 (4): 2926-2936, Jul 2020 10.1109/TPWRS.2019.2962024
- C. Gentile, G. Morales-España, and A. Ramos "A tight MIP formulation of the unit commitment problem with start-up and shut-down constraints" EURO Journal on Computational Optimization 5 (1), 177-201, Mar 2017. 10.1007/s13675-016-0066-y
- G. Morales-España, A. Ramos, and J. Garcia-Gonzalez "An MIP Formulation for Joint Market-Clearing of Energy and Reserves Based on Ramp Scheduling" IEEE Transactions on Power Systems 29 (1): 476-488, Jan 2014. 10.1109/TPWRS.2013.2259601
- G. Morales-España, J.M. Latorre, and A. Ramos "Tight and Compact MILP Formulation for the Thermal Unit Commitment Problem" IEEE Transactions on Power Systems 28 (4): 4897-4908, Nov 2013. 10.1109/TPWRS.2013.2251373

$$\frac{p_{\omega png} + URA\, ur_{\omega png} + ur_{\omega png}}{\overline{GP}_g - \underline{GP}_g} \leq uc_{\omega png} \quad \forall \omega png$$

$$\frac{p_{\omega png} - DRA\, dr_{\omega png} - dr_{\omega png}}{\overline{GP}_g - \underline{GP}_g} \geq 0 \quad \forall \omega png$$

Ricobayo
hydroelectric
power plant



Constraints. Charge/discharge of ESS. Commitment, startup, shutdown

Maximum and minimum charge of an ESS [p.u.]

$$\frac{c_{\omega pne}+URA\,dr'_{\omega pne}+dr'_{\omega pne}}{\overline{GC}_e} \leq 1 \quad \forall \omega pne$$

$$\frac{c_{\omega pne}-DRA\,ur'_{\omega pne}-ur'_{\omega pne}}{\overline{GC}_e} \geq 0 \quad \forall \omega pne$$

Source: Wikipedia

Incompatibility between charge and discharge of an ESS [p.u.]

$$\frac{p_{\omega pne}+URA\,ur'_{\omega pne}+ur_{\omega png}}{\overline{GP}_e-\underline{GP}_e} + \frac{c_{\omega pne}+URA\,dr'_{\omega pne}+dr'_{\omega pne}}{\overline{GC}_e} \leq 1 \quad \forall \omega pne, e \in CE$$

Total output of a committed unit (all except the VRES units) [GW]

$$\frac{gp_{\omega png}}{\underline{GP}_g} = uc_{\omega png} + \frac{p_{\omega png}+URA\,ur_{\omega png}-DRA\,dr_{\omega png}}{\underline{GP}_g} \quad \forall \omega png$$

Total charge of an ESS unit [GW]

$$gc_{\omega pne} = c_{\omega pne} + URA\,dr'_{\omega pne} - DRA\,ur'_{\omega pne} \quad \forall \omega pne, e \in CE$$

Logical relation between commitment, startup and shutdown status of committed unit (all except the VRES units) [p.u.]

$$uc_{\omega png} - uc_{\omega p,n-\nu,g} = su_{\omega png} - sd_{\omega png} \quad \forall \omega png$$

Initial commitment of the units is determined by the model based on the merit order loading, including the VRES and ESS units.

Constraints. Ramps, minimum up- and downtime

Maximum ramp up and ramp down for the second block of a thermal unit [p.u.]

- P. Damcı-Kurt, S. Küçükyavuz, D. Rajan, and A. Atamtürk, “A polyhedral study of production ramping,” Math. Program., vol. 158, no. 1–2, pp. 175–205, Jul. 2016. 10.1007/s10107-015-0919-9

$$\frac{-p_{\omega p,n-\nu,t} - URA\ ur_{\omega p,n-\nu,t} + p_{\omega pnt} + URA\ ur_{\omega pnt} + ur_{\omega pnt}}{DUR_n RU_t} \leq uc_{\omega pnt} - su_{\omega pnt} \quad \forall \omega pnt$$

$$\frac{-p_{\omega p,n-\nu,t} + DRA\ dr_{\omega p,n-\nu,t} + p_{\omega pnt} - DRA\ dr_{\omega pnt} - dr_{\omega pnt}}{DUR_n RD_t} \geq -uc_{\omega p,n-\nu,t} + sd_{\omega pnt} \quad \forall \omega pnt$$

Minimum up time and down time of thermal unit [h]

- D. Rajan and S. Takriti, “Minimum up/down polytopes of the unit commitment problem with start-up costs,” IBM, New York, Technical Report RC23628, 2005. https://pdfs.semanticscholar.org/b886/42e36b414d5929fed48593d0ac46ae3e2070.pdf

$$\textstyle\sum_{n'=n+\nu-TU_t}^{n} su_{\omega pn't} \leq uc_{\omega pnt} \quad \forall \omega pnt$$

$$\textstyle\sum_{n'=n+\nu-TD_t}^{n} sd_{\omega pn't} \leq 1 - uc_{\omega pnt} \quad \forall \omega pnt$$

Constraints. Transmission network. DC power flow

Transfer capacity in candidate transmission lines [p.u.]

$$-ict_{ijc} \leq \frac{f_{\omega pnijc}}{\overline{F}'_{ijc}} \leq ict_{ijc} \quad \forall \omega pnijc, ijc \in CL$$

DC Power flow for existing and candidate AC-type lines (Kirchhoff's second law) [rad]

$$\frac{f_{\omega pnijc}}{\overline{F}'_{ijc}} = (\theta_{\omega pni} - \theta_{\omega pnj})\frac{S_B}{X_{ijc}\overline{F}'_{ijc}} \quad \forall \omega pnijc, ijc \in EL$$

$$-1 + ict_{ijc} \leq \frac{f_{\omega pnijc}}{\overline{F}'_{ijc}} - (\theta_{\omega pni} - \theta_{\omega pnj})\frac{S_B}{X_{ijc}\overline{F}'_{ijc}} \leq 1 - ict_{ijc} \quad \forall \omega pnijc, ijc \in CL$$

Half ohmic losses are linearly approximated as a function of the flow [GW]

$$-\frac{L_{ijc}}{2} f_{\omega pnijc} \leq l_{\omega pnijc} \geq \frac{L_{ijc}}{2} f_{\omega pnijc} \quad \forall \omega pnijc$$

Source: REE

Constraints. Bounds

Bounds on generation variables [GW]

$$0 \leq gp_{\omega png} \leq \overline{GP}_g \quad \forall \omega png$$

$$0 \leq qc_{\omega pne} \leq \overline{GC}_e \quad \forall \omega pne$$

$$0 \leq ur_{\omega png} \leq \overline{CP}_g - \underline{GP}_g \quad \forall \omega png$$

$$0 \leq ur'_{\omega pne} \leq \overline{CP}_e - \underline{GP}_e \quad \forall \omega pne$$

$$0 \leq dr_{\omega png} \leq \overline{CP}_g - \underline{GP}_g \quad \forall \omega png$$

$$0 \leq dr'_{\omega pne} \leq \overline{CP}_e - \underline{GP}_e \quad \forall \omega pne$$

$$0 \leq p_{\omega png} \leq \overline{GP}_g - \underline{GP}_g \quad \forall \omega png$$

$$0 \leq c_{\omega pne} \leq \overline{GC}_e \quad \forall \omega pne$$

$$0 \leq i_{\omega pne} \leq I_e \quad \forall \omega pne$$

$$0 \leq s_{\omega pne} \quad \forall \omega pne$$

$$0 \leq ens_{\omega pni} \leq D_{\omega pni} \quad \forall \omega pni$$

Bounds on network variables [GW]

$$0 \leq l_{\omega pnijc} \leq \frac{L_{ijc}}{2} \overline{F}_{ijc} \quad \forall \omega pnijc$$

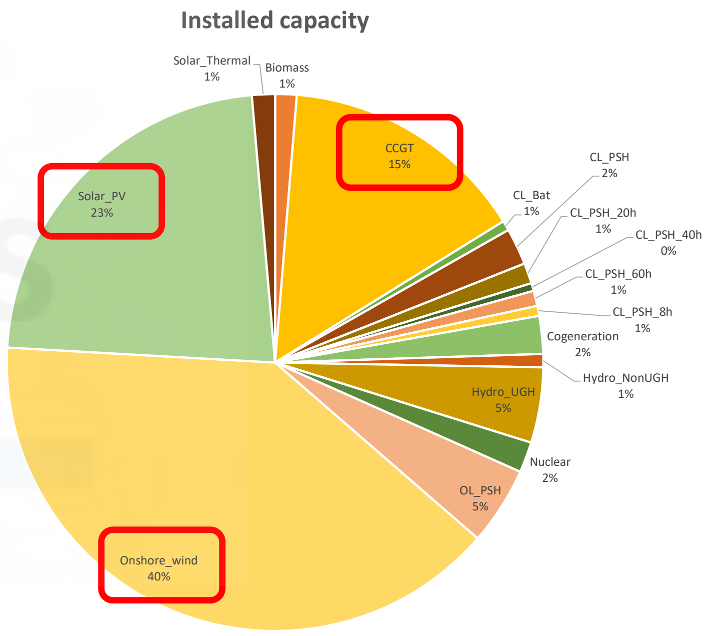
$$-\overline{F}_{ijc} \leq f_{\omega pnijc} \leq \overline{F}_{ijc} \quad \forall \omega pnijc, ijc \in EL$$

Voltage angle of the reference node fixed to 0 for each scenario, period, and load level [rad]

$$\theta_{\omega pn, node_{ref}} = 0$$

Case study: Spain 2030

- 10-year Integrated National Energy and Climate Plan (NECP)
- Installed capacity: 165,000 MW
- Half of the nuclear units phased out (3,100 MW), no coal units, existing CCGT (24,500 MW)
- Significant investments in solar PV (37,500 MW) and onshore wind (65,200 MW)
- Existing (11,500 MW) and additional pumped-storage hydro (5,300 MW)
- Batteries forced to be installed (1,000 MW)



Why flexibility will be needed in future electric systems?

1. Conventional generation is being phased out
2. VRES introduce additional flexibility requirements
    – Flexibility mechanisms:

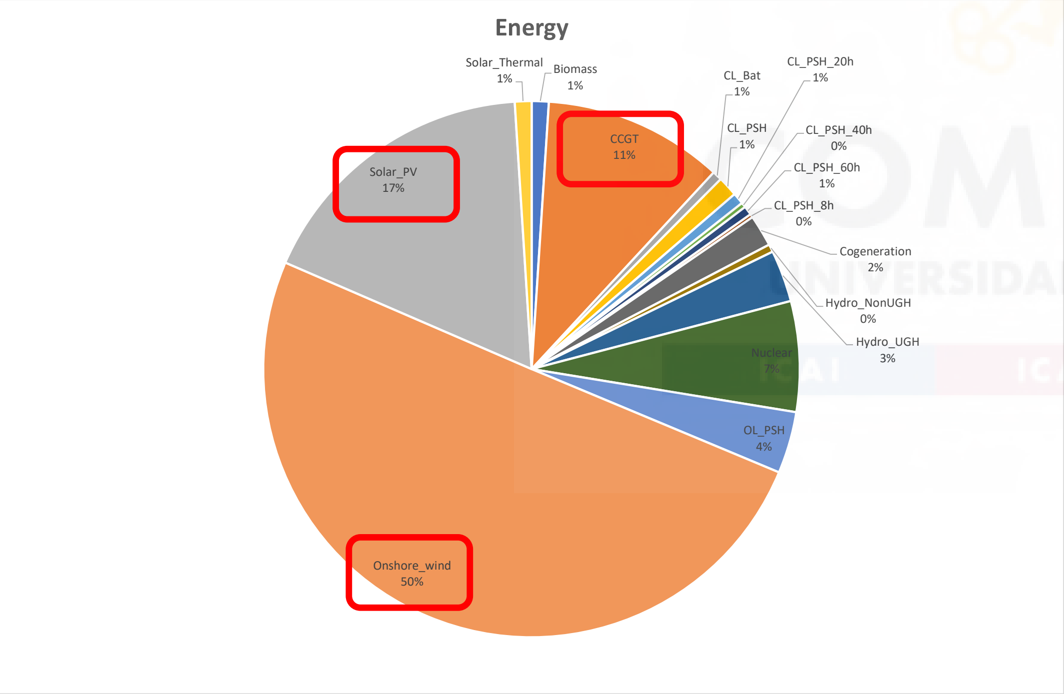
- ESS (Energy Storage Systems) (PSH, batteries)
- Flexible electricity generation (CCGT, hydro)
- Solar Thermal
- Flexible demand (DSM)
- Electric Vehicle (EV)
- Grid expansion

Operational flexibility

- Ability of the system to withstand the uncertainty and variability in generation and electricity demand while maintaining the desired reliability at an affordable cost
- Measure: the contribution of each dispatchable technology to the variation of the (net) demand at different time horizons (monthly, weekly, daily)

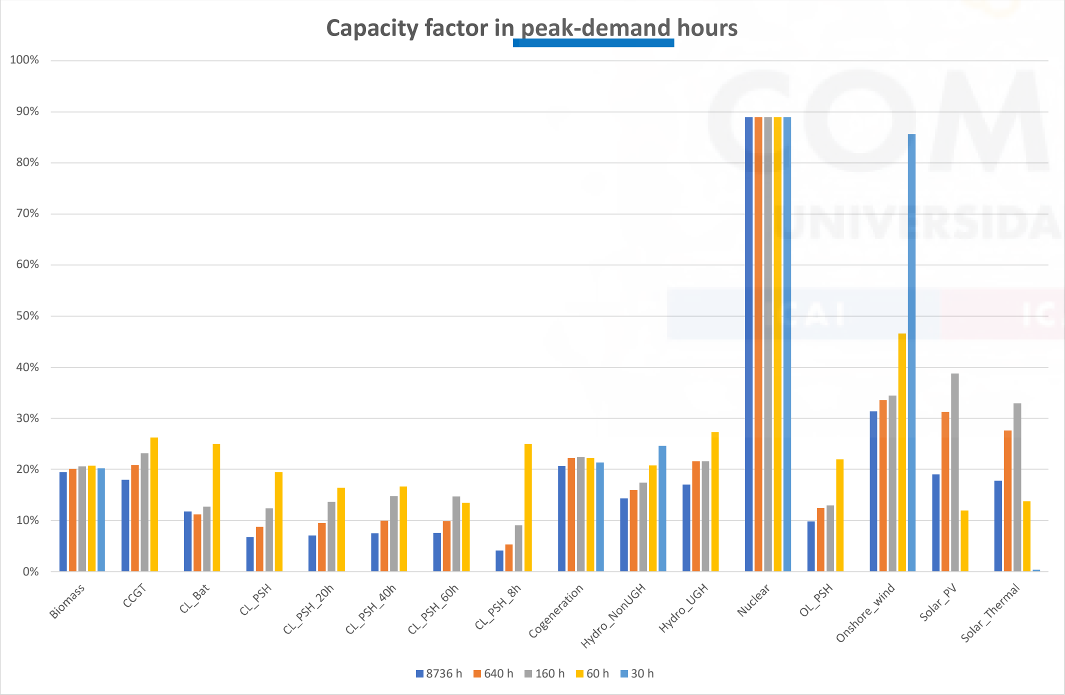
System operation

Energy demand: 334,270 GWh

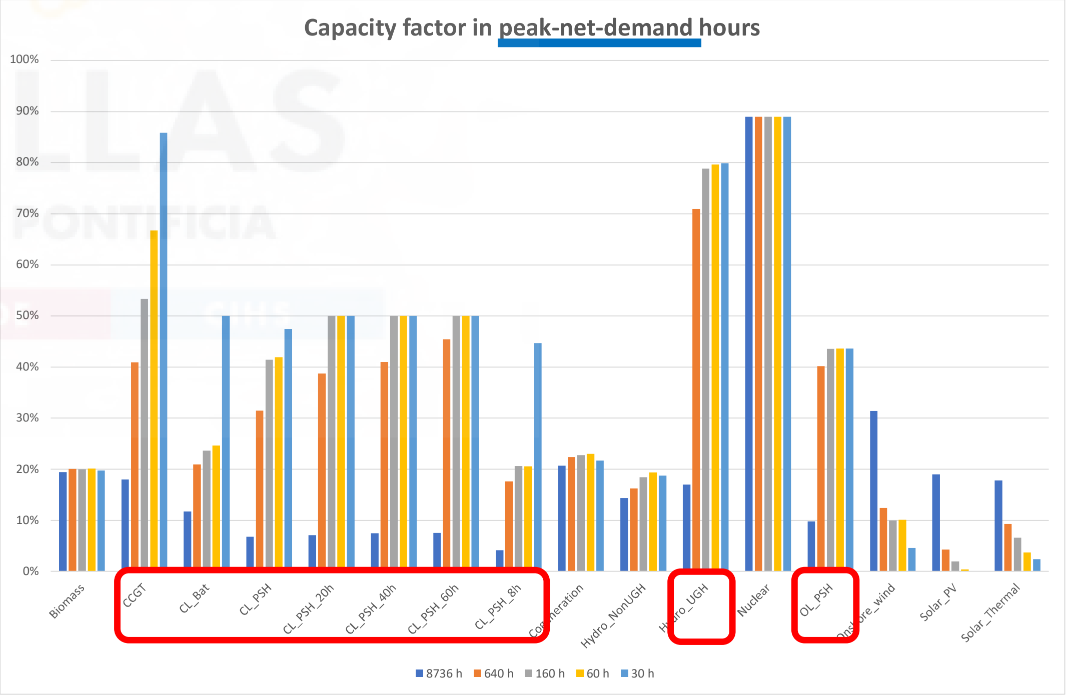


Firmness/Electric Load Carrying Capability (ELCC)

- Capacity factors of the different technologies at peak hours of demand and net demand



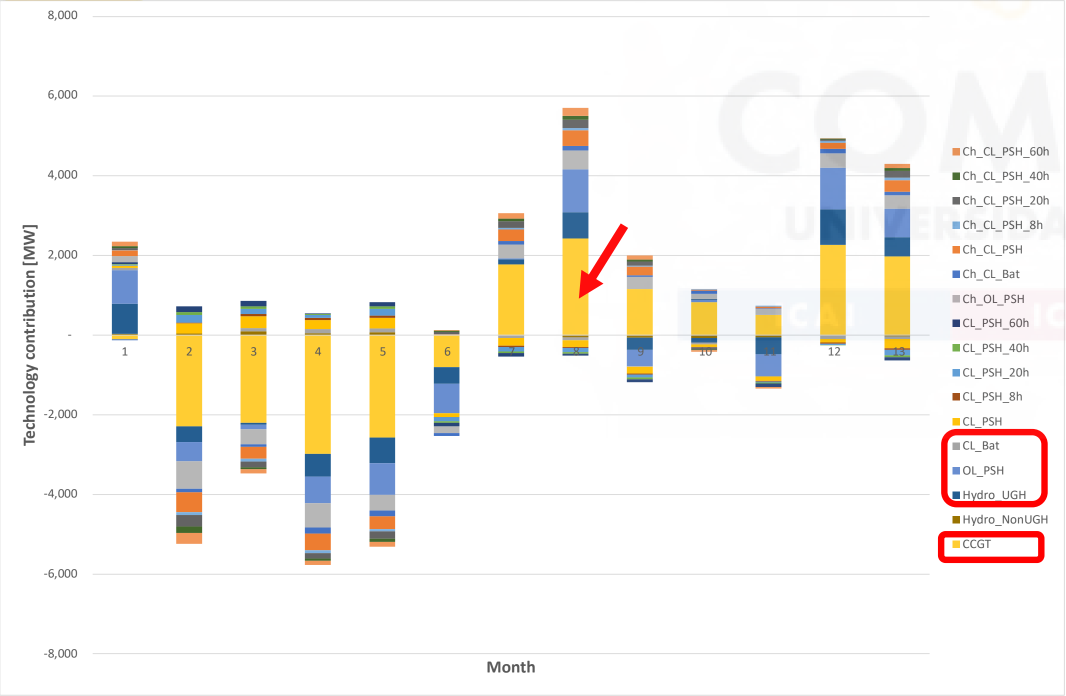
Capacity factor in peak-demand hours

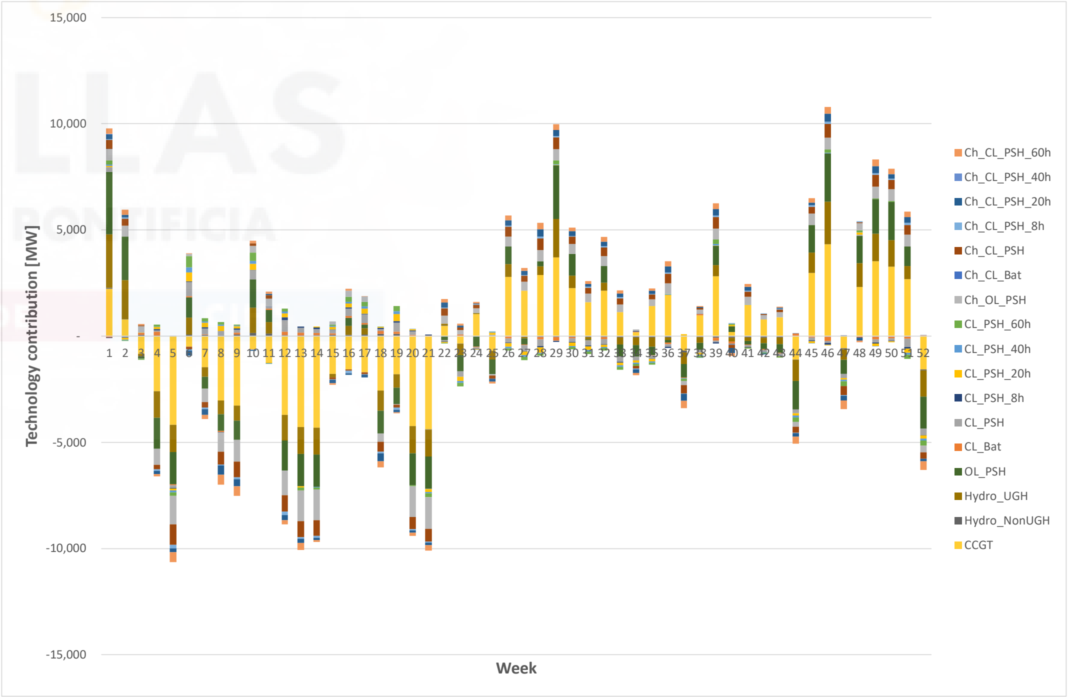


Capacity factor in peak-net-demand hours

Flexibility

Technology contribution to the monthly/weekly variation of the net demand (difference between the value and its mean)





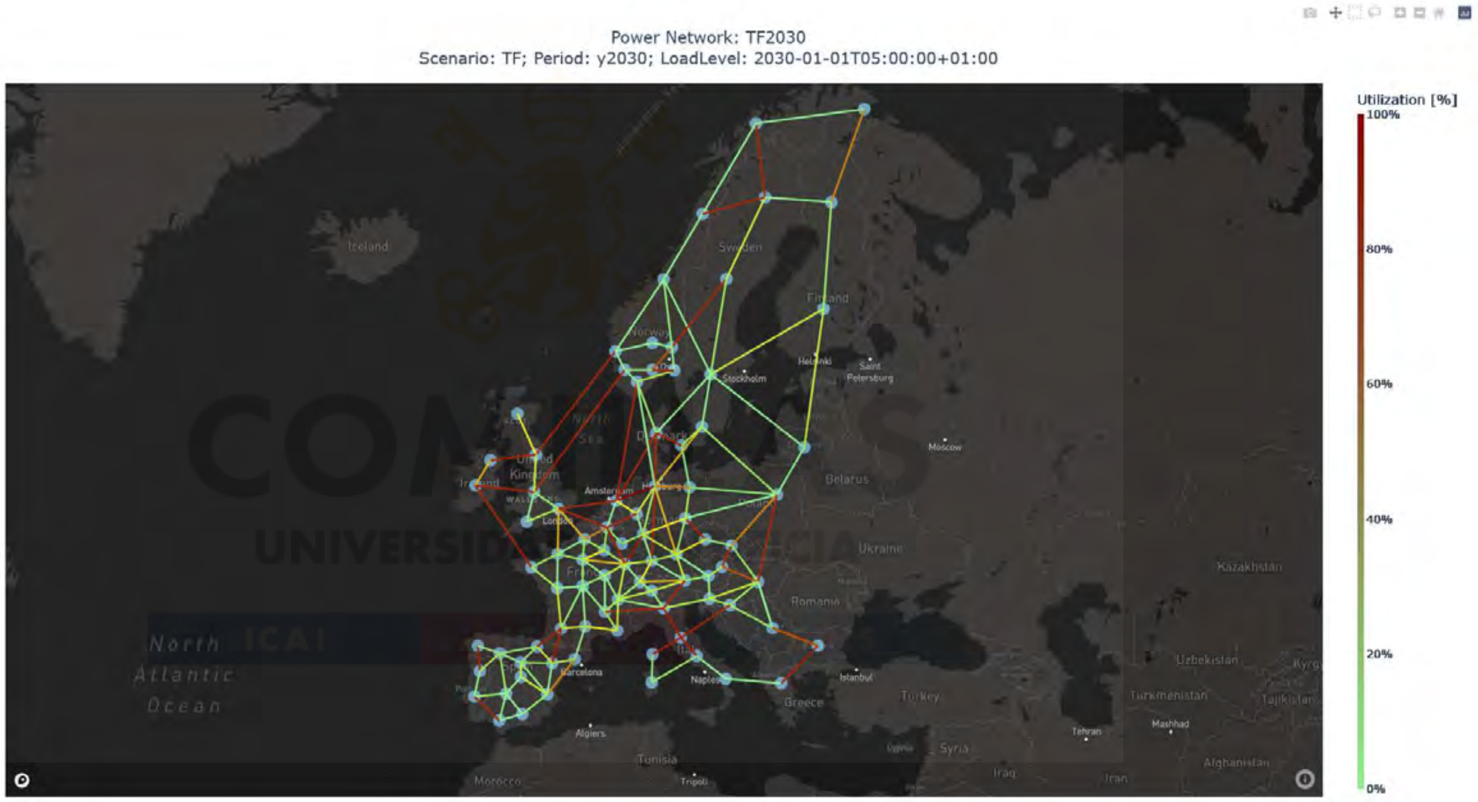
Conclusions

- Future electric systems with a high share of VRES will require flexible generation and ESS
- A detailed operation model is mandatory and suitable for capturing the operation of ESS
- At peak net-demand hours, CCGT, hydro, open- and closed-loop PSH have larger capacity factors while VRES decrease their capacity factor
- Flexibility provided by CCGT, hydro, PSH, and batteries
- The higher the storage capacity the more ESS is used (PSH with large reservoirs preferred over smaller ones). Batteries compete with the PSH with small size (8 h)

MAF (Mid Term Adequacy Forecast) 2020

(https://www.entsoe.eu/outlooks/maf/Pages/default.aspx)

- How is the European system going to be in 2025 and 2030 from an adequacy point of view?

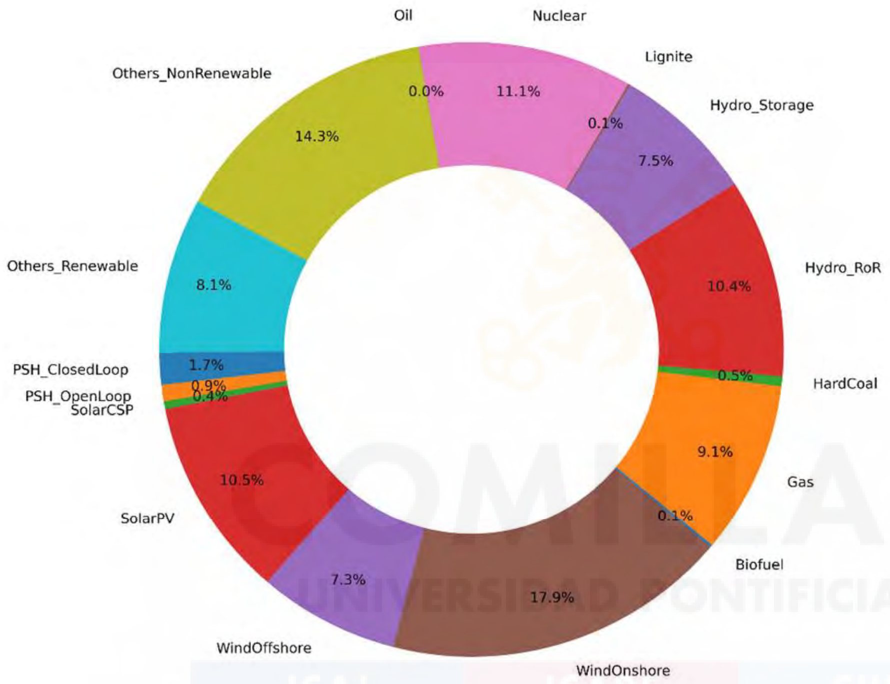


Power Network: TF2030
Scenario: TF; Period: y2030; LoadLevel: 2030-01-01T05:00:00+01:00

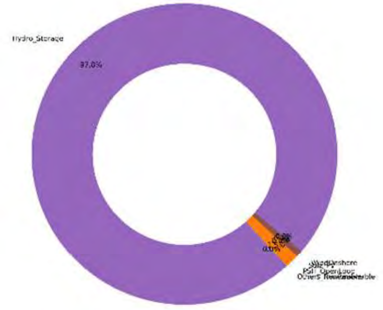
- Like Reliability Assessment and Performance Analysis done by NERC in the USA

Energy generation mix

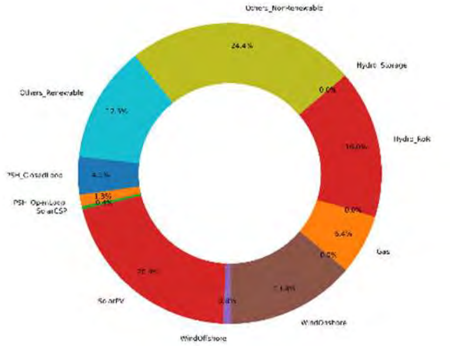
Europe



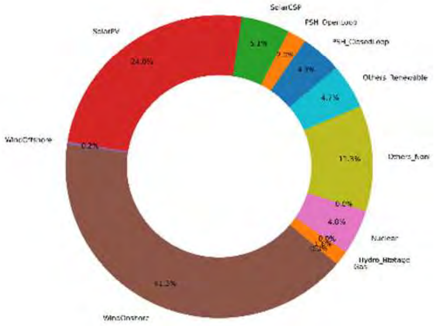
Norway



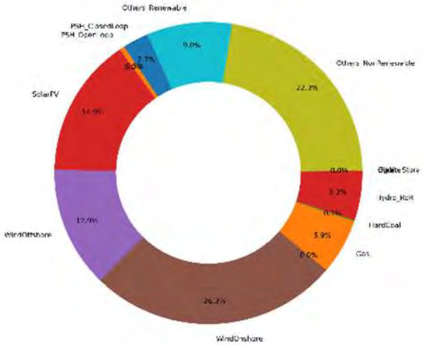
Italy



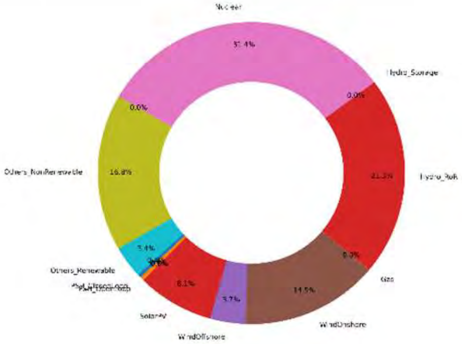
Spain



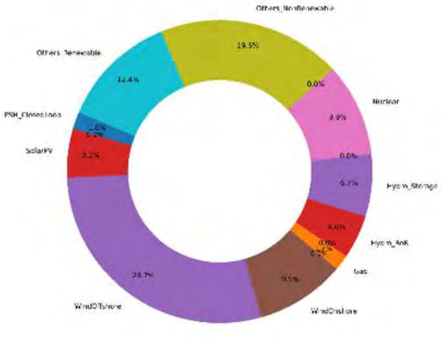
Germany



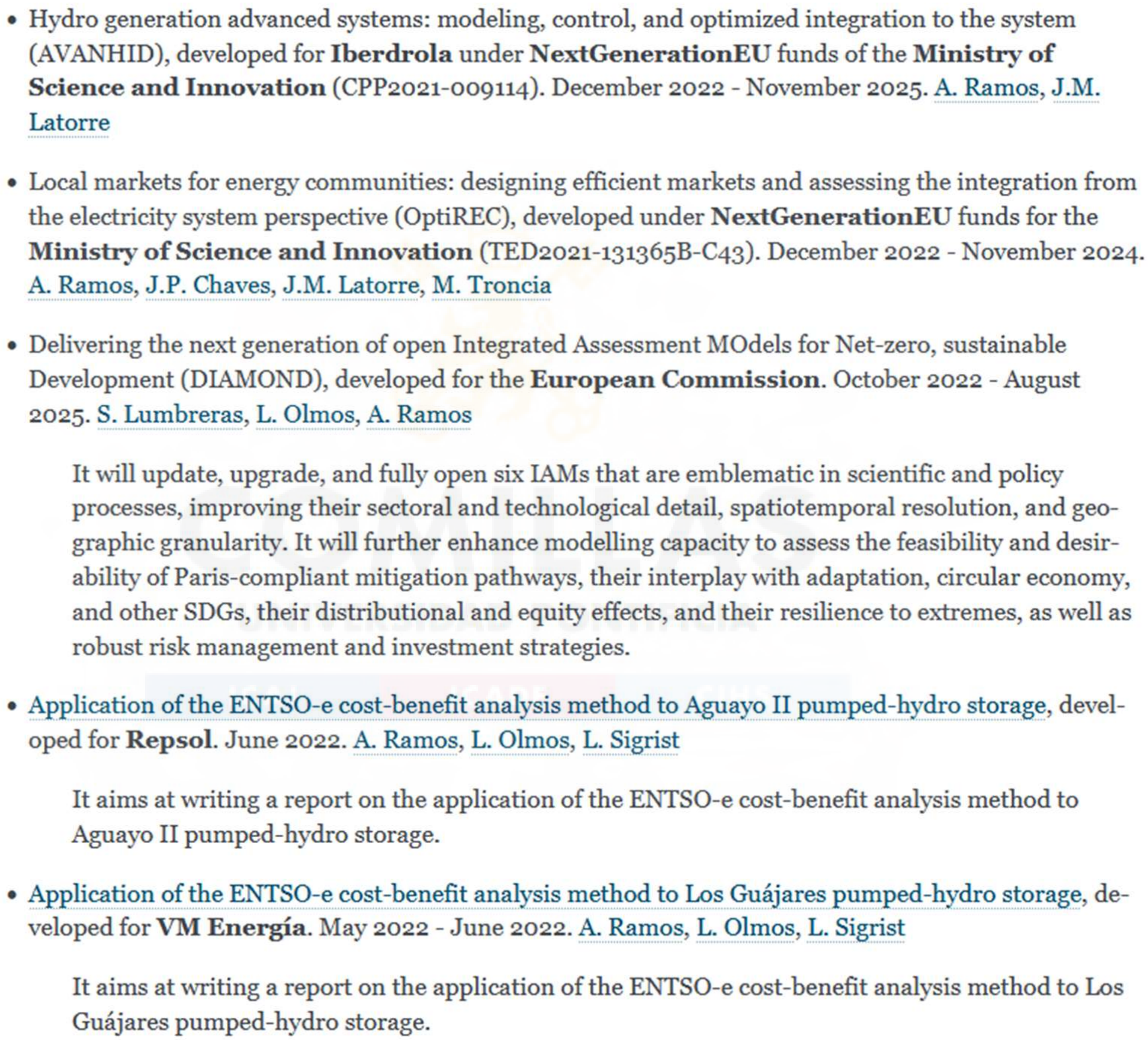
France



UK



Research projects (i)



- Hydro generation advanced systems: modeling, control, and optimized integration to the system (AVANHID), developed for **Iberdrola** under **NextGenerationEU** funds of the **Ministry of Science and Innovation** (CPP2021-009114). December 2022 - November 2025. A. Ramos, J.M. Latorre
- Local markets for energy communities: designing efficient markets and assessing the integration from the electricity system perspective (OptiREC), developed under **NextGenerationEU** funds for the **Ministry of Science and Innovation** (TED2021-131365B-C43). December 2022 - November 2024. A. Ramos, J.P. Chaves, J.M. Latorre, M. Troncia
- Delivering the next generation of open Integrated Assessment MOdels for Net-zero, sustainable Development (DIAMOND), developed for the **European Commission**. October 2022 - August 2025. S. Lumbreras, L. Olmos, A. Ramos

  It will update, upgrade, and fully open six IAMs that are emblematic in scientific and policy processes, improving their sectoral and technological detail, spatiotemporal resolution, and geographic granularity. It will further enhance modelling capacity to assess the feasibility and desirability of Paris-compliant mitigation pathways, their interplay with adaptation, circular economy, and other SDGs, their distributional and equity effects, and their resilience to extremes, as well as robust risk management and investment strategies.
- Application of the ENTSO-e cost-benefit analysis method to Aguayo II pumped-hydro storage, developed for **Repsol**. June 2022. A. Ramos, L. Olmos, L. Sigrist

  It aims at writing a report on the application of the ENTSO-e cost-benefit analysis method to Aguayo II pumped-hydro storage.
- Application of the ENTSO-e cost-benefit analysis method to Los Guájares pumped-hydro storage, developed for **VM Energía**. May 2022 - June 2022. A. Ramos, L. Olmos, L. Sigrist

  It aims at writing a report on the application of the ENTSO-e cost-benefit analysis method to Los Guájares pumped-hydro storage.

Research projects (ii)

- Impact of the electric vehicle in the electricity markets in 2030, developed for **Repsol**. November 2021 - February 2022. A. Ramos, P. Frías, J.P. Chaves, P. Linares, J.J. Valentín

  It aims at analyzing the impact on the electricity markets of the mainland Spanish system of the high penetration of electric vehicles in a 2030 scenario.

- European Climate and Energy Modelling Forum (ECEMF), developed for the **European Commission**. May 2021 - December 2024. S. Lumbreras, A. Ramos, L. Olmos, C. Mateo, D. Santos Oliveira

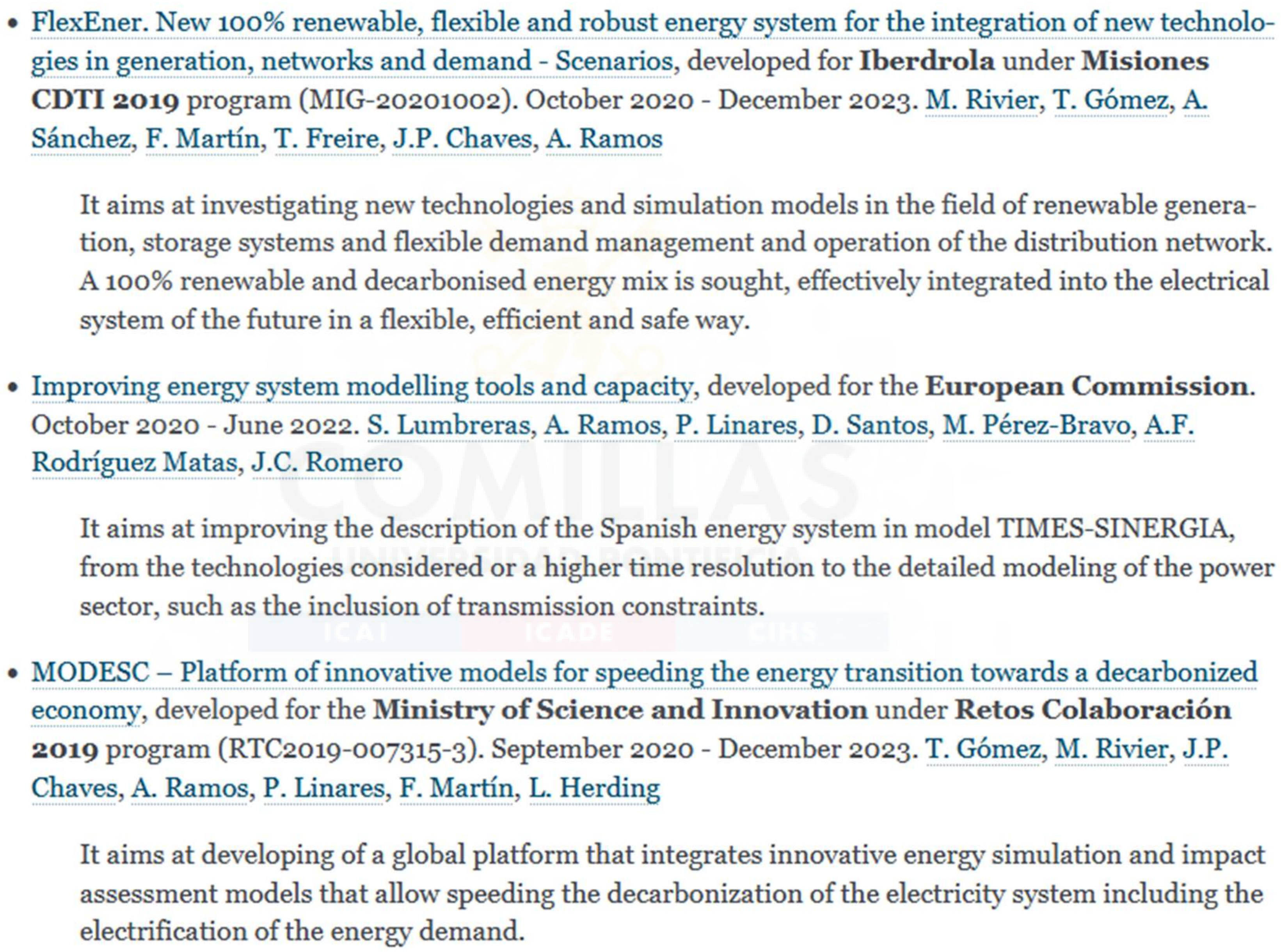
  It aims at providing the knowledge to inform the development of future energy and climate policies at national and European levels. In support of this aim, ECEMF proposes a range of activities to achieve five objectives and meet the four challenges set out in the call text. ECEMF's programme of events and novel IT-based communications channel will enable researchers to identify and co-develop the most pressing policy-relevant research questions with a range of stakeholders to meet ambitious European energy and climate policy goals, in particular the European Green Deal and the transformation to a climate neutral society.

  EUROPEAN
  CLIMATE+ENERGY
  MODELLING
  FORUM

- Assessment of the storage needs for the Spanish electric system in a horizon 2020-2050 with large share of renewables, developed for the **Instituto para la Diversificación y Ahorro de la Energía (IDAE)**. January 2021 - June 2022. A. Ramos, P. Linares, J.P. Chaves, J. García, S. Wogrin, J.J. Valentín

  It aims at assessing, from a technical and economic point of view, the daily, weekly, and seasonal storage needs for the Spanish electricity system in the 2020-2050 horizon.

Research projects (iii)



- FlexEner. New 100% renewable, flexible and robust energy system for the integration of new technologies in generation, networks and demand - Scenarios, developed for **Iberdrola** under **Misiones CDTI 2019** program (MIG-20201002). October 2020 - December 2023. M. Rivier, T. Gómez, A. Sánchez, F. Martín, T. Freire, J.P. Chaves, A. Ramos

  It aims at investigating new technologies and simulation models in the field of renewable generation, storage systems and flexible demand management and operation of the distribution network. A 100% renewable and decarbonised energy mix is sought, effectively integrated into the electrical system of the future in a flexible, efficient and safe way.

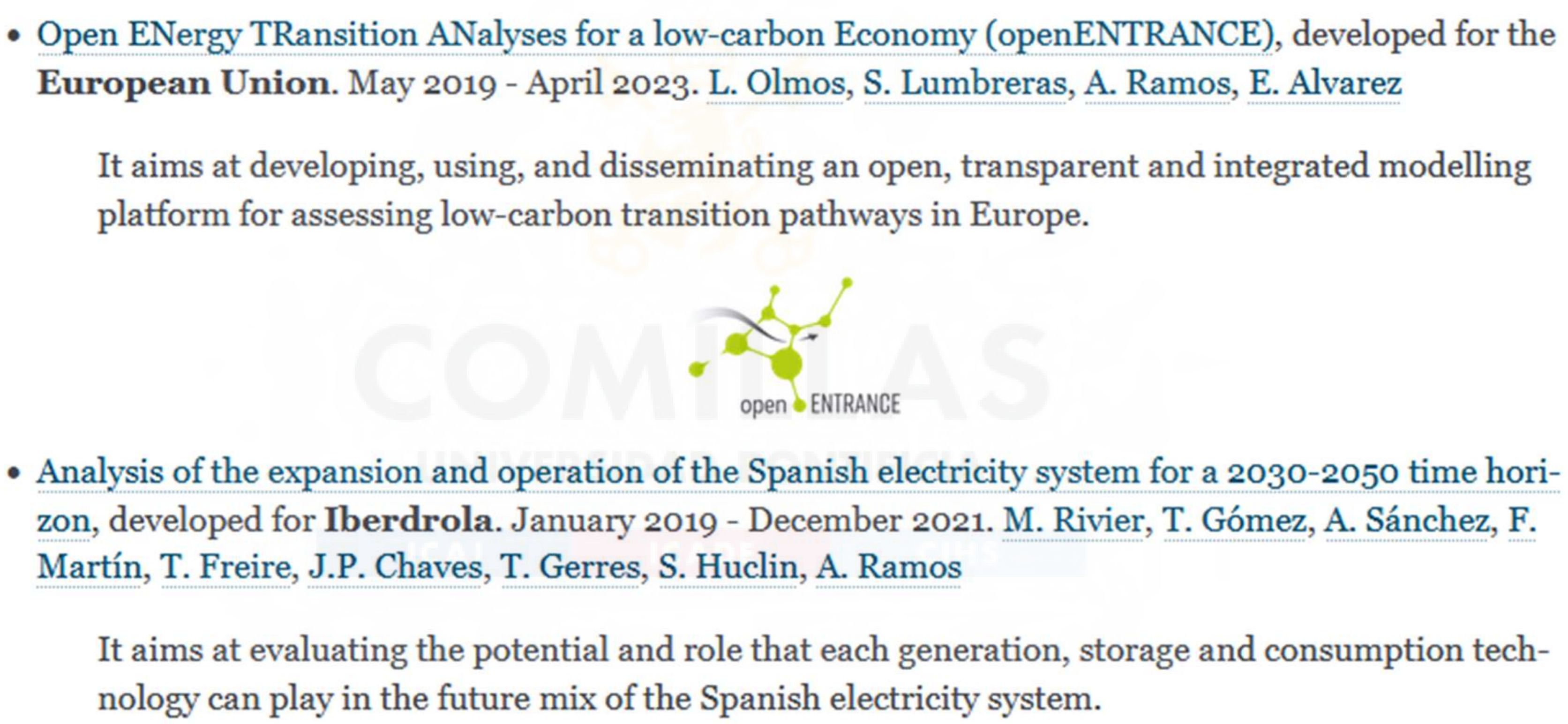
- Improving energy system modelling tools and capacity, developed for the **European Commission**. October 2020 - June 2022. S. Lumbreras, A. Ramos, P. Linares, D. Santos, M. Pérez-Bravo, A.F. Rodríguez Matas, J.C. Romero

  It aims at improving the description of the Spanish energy system in model TIMES-SINERGIA, from the technologies considered or a higher time resolution to the detailed modeling of the power sector, such as the inclusion of transmission constraints.

- MODESC – Platform of innovative models for speeding the energy transition towards a decarbonized economy, developed for the **Ministry of Science and Innovation** under **Retos Colaboración 2019** program (RTC2019-007315-3). September 2020 - December 2023. T. Gómez, M. Rivier, J.P. Chaves, A. Ramos, P. Linares, F. Martín, L. Herding

  It aims at developing of a global platform that integrates innovative energy simulation and impact assessment models that allow speeding the decarbonization of the electricity system including the electrification of the energy demand.

Research projects (iv)



- Open ENergy TRansition ANalyses for a low-carbon Economy (openENTRANCE), developed for the **European Union**. May 2019 - April 2023. L. Olmos, S. Lumbreras, A. Ramos, E. Alvarez

  It aims at developing, using, and disseminating an open, transparent and integrated modelling platform for assessing low-carbon transition pathways in Europe.

- Analysis of the expansion and operation of the Spanish electricity system for a 2030-2050 time horizon, developed for **Iberdrola**. January 2019 - December 2021. M. Rivier, T. Gómez, A. Sánchez, F. Martín, T. Freire, J.P. Chaves, T. Gerres, S. Huclin, A. Ramos

  It aims at evaluating the potential and role that each generation, storage and consumption technology can play in the future mix of the Spanish electricity system.

StarNetLite_TEPM Long-Term Transmission Expansion Model (https://pascua.iit.comillas.edu/aramos/StarNetLite_TEPM.zip)

- Files
  - Microsoft Excel interface for input data and output results StarNetLite_TEPM.xlsm
  - GAMS file StarNetLite_TEPM.gms
- How to run it from Windows
  - Save the Excel workbook if data have changed
  - Run the model

    Run

  - The model creates
    - tmp_ StarNetLite_TEPM.xlsx with the output results
    - tmp_ StarNetLite_TEPM.gdx with the output results
    - StarNetLite_TEPM.lst as the listing file of the GAMS execution
  - Load the results into the Excel interface

    Load results

StarNetLite_TEPM Long-Term Transmission Expansion Model (https://pascua.iit.comillas.edu/aramos/StarNetLite_TEPM.zip)

- Files
  - – Text files for input data
  - – GAMS file StarNetLite_TEPM.gms

- How to run it from MacOS
  - – Run the model from GAMS Studio with these parameters
    - u1= StarNetLite_TEPM u2=1 u3=1
  - – The model creates
    - tmp_ StarNetLite_TEPM.gdx with the output results
    - StarNetLite_TEPM.lst as the listing file of the GAMS execution

Menu

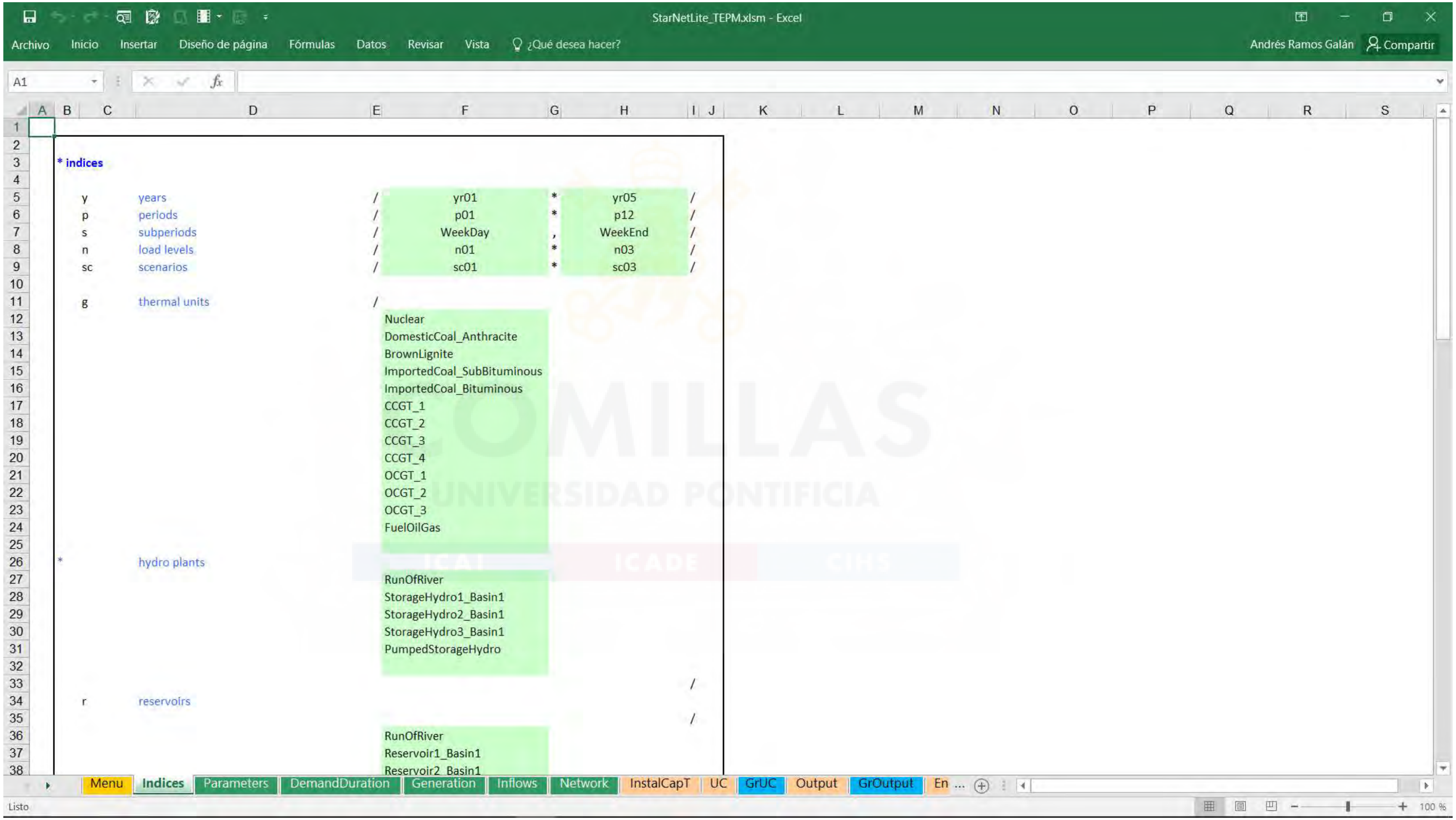
StarNet Lite *Long Term Transmission Expansion Planning Model*

Andrés Ramos

https://www.iit.comillas.edu/aramos/

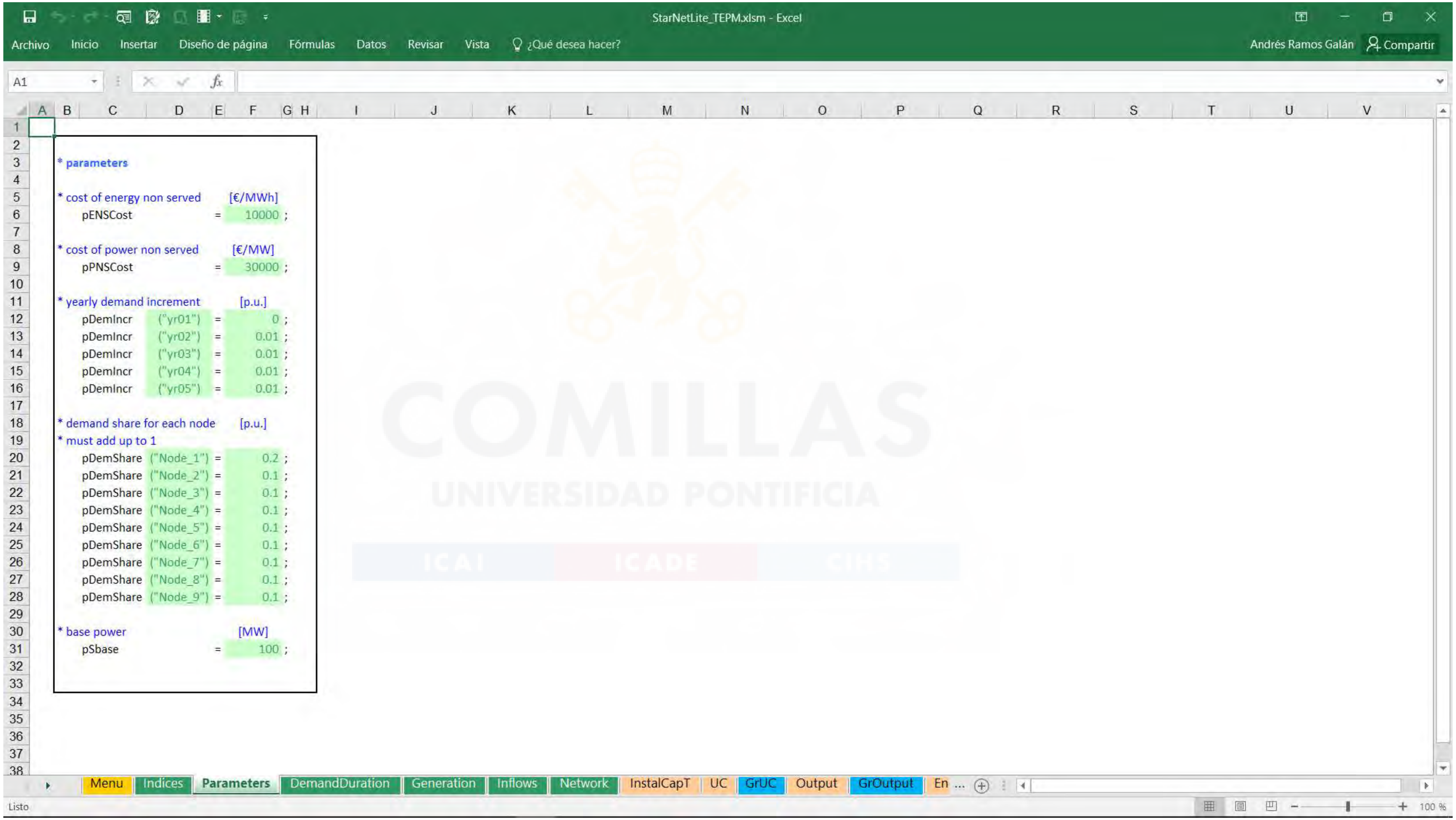
andres.ramos@comillas.edu

Input Data. Indices



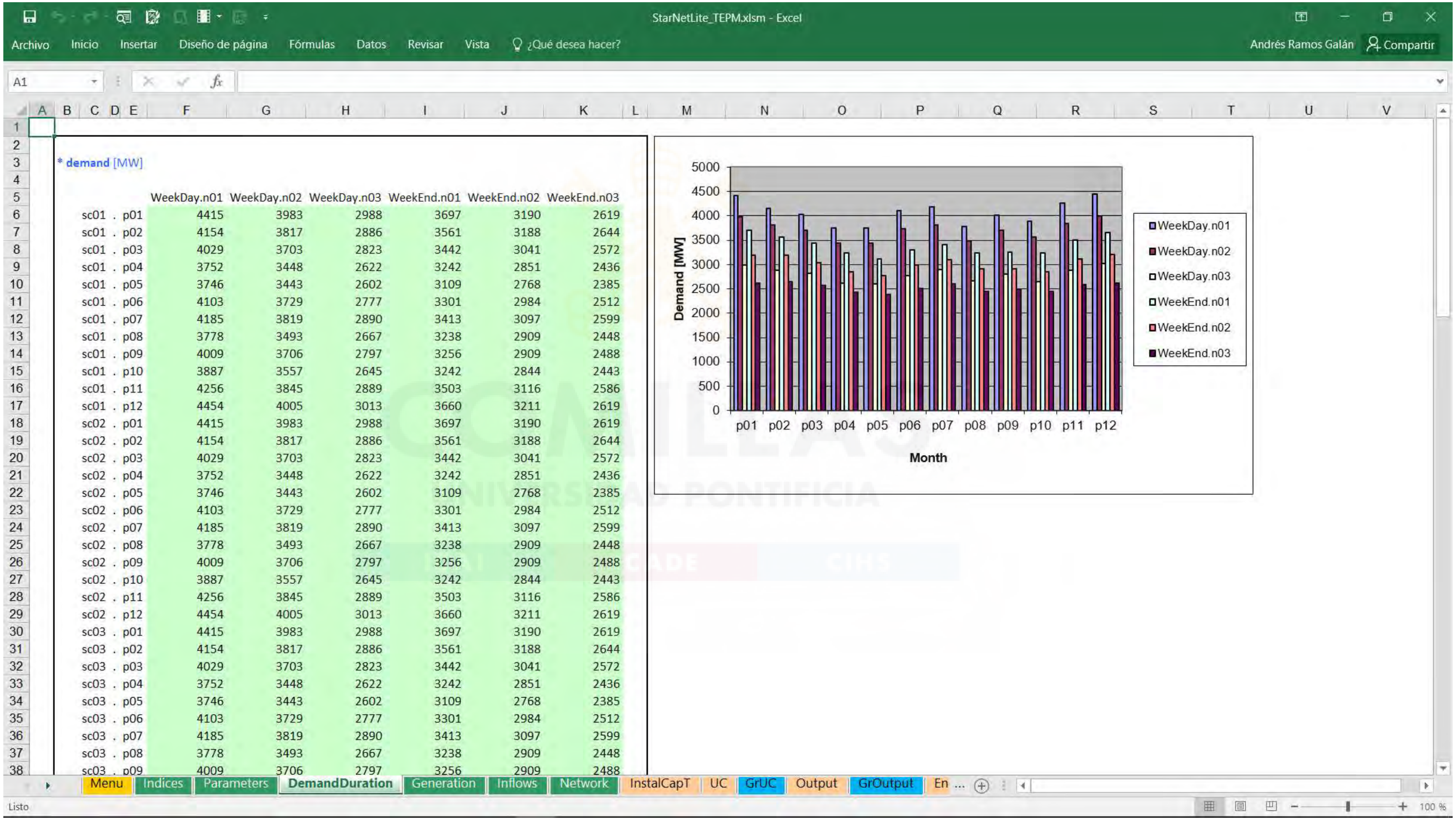
	A	B	C	D	E	F	G	H	I
1									
2									
3		* indices							
4									
5			y	years	/	yr01	*	yr05	/
6			p	periods	/	p01	*	p12	/
7			s	subperiods	/	WeekDay	,	WeekEnd	/
8			n	load levels	/	n01	*	n03	/
9			sc	scenarios	/	sc01	*	sc03	/
10									
11			g	thermal units	/				
12						Nuclear			
13						DomesticCoal_Anthracite			
14						BrownLignite			
15						ImportedCoal_SubBituminous			
16						ImportedCoal_Bituminous			
17						CCGT_1			
18						CCGT_2			
19						CCGT_3			
20						CCGT_4			
21						OCGT_1			
22						OCGT_2			
23						OCGT_3			
24						FuelOilGas			
25									
26		*		hydro plants					
27						RunOfRiver			
28						StorageHydro1_Basin1			
29						StorageHydro2_Basin1			
30						StorageHydro3_Basin1			
31						PumpedStorageHydro			
32									
33									/
34			r	reservoirs					
35									/
36						RunOfRiver			
37						Reservoir1_Basin1			
38						Reservoir2_Basin1			

Input Data. Cost of energy or power not served. Demand growth. Base power



```
* parameters

* cost of energy non served        [€/MWh]
    pENSCost                  =    10000 ;

* cost of power non served          [€/MW]
    pPNSCost                  =    30000 ;

* yearly demand increment            [p.u.]
    pDemIncr    ("yr01")      =        0 ;
    pDemIncr    ("yr02")      =     0.01 ;
    pDemIncr    ("yr03")      =     0.01 ;
    pDemIncr    ("yr04")      =     0.01 ;
    pDemIncr    ("yr05")      =     0.01 ;

* demand share for each node         [p.u.]
* must add up to 1
    pDemShare ("Node_1")      =      0.2 ;
    pDemShare ("Node_2")      =      0.1 ;
    pDemShare ("Node_3")      =      0.1 ;
    pDemShare ("Node_4")      =      0.1 ;
    pDemShare ("Node_5")      =      0.1 ;
    pDemShare ("Node_6")      =      0.1 ;
    pDemShare ("Node_7")      =      0.1 ;
    pDemShare ("Node_8")      =      0.1 ;
    pDemShare ("Node_9")      =      0.1 ;

* base power                          [MW]
    pSbase                    =      100 ;
```

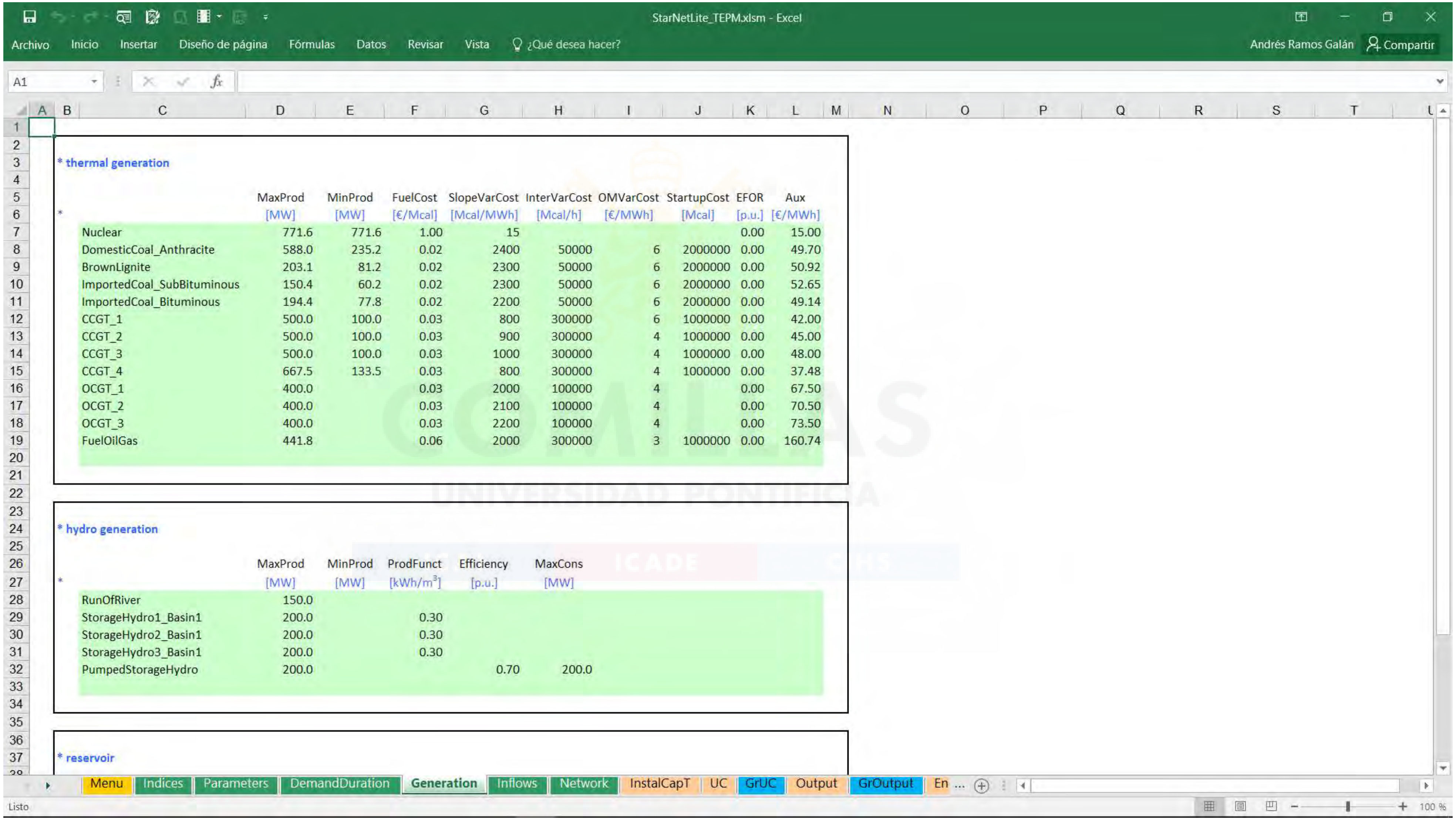
Input Data. Demand, operating reserve and duration



* **demand** [MW]

	WeekDay.n01	WeekDay.n02	WeekDay.n03	WeekEnd.n01	WeekEnd.n02	WeekEnd.n03
sc01 . p01	4415	3983	2988	3697	3190	2619
sc01 . p02	4154	3817	2886	3561	3188	2644
sc01 . p03	4029	3703	2823	3442	3041	2572
sc01 . p04	3752	3448	2622	3242	2851	2436
sc01 . p05	3746	3443	2602	3109	2768	2385
sc01 . p06	4103	3729	2777	3301	2984	2512
sc01 . p07	4185	3819	2890	3413	3097	2599
sc01 . p08	3778	3493	2667	3238	2909	2448
sc01 . p09	4009	3706	2797	3256	2909	2488
sc01 . p10	3887	3557	2645	3242	2844	2443
sc01 . p11	4256	3845	2889	3503	3116	2586
sc01 . p12	4454	4005	3013	3660	3211	2619
sc02 . p01	4415	3983	2988	3697	3190	2619
sc02 . p02	4154	3817	2886	3561	3188	2644
sc02 . p03	4029	3703	2823	3442	3041	2572
sc02 . p04	3752	3448	2622	3242	2851	2436
sc02 . p05	3746	3443	2602	3109	2768	2385
sc02 . p06	4103	3729	2777	3301	2984	2512
sc02 . p07	4185	3819	2890	3413	3097	2599
sc02 . p08	3778	3493	2667	3238	2909	2448
sc02 . p09	4009	3706	2797	3256	2909	2488
sc02 . p10	3887	3557	2645	3242	2844	2443
sc02 . p11	4256	3845	2889	3503	3116	2586
sc02 . p12	4454	4005	3013	3660	3211	2619
sc03 . p01	4415	3983	2988	3697	3190	2619
sc03 . p02	4154	3817	2886	3561	3188	2644
sc03 . p03	4029	3703	2823	3442	3041	2572
sc03 . p04	3752	3448	2622	3242	2851	2436
sc03 . p05	3746	3443	2602	3109	2768	2385
sc03 . p06	4103	3729	2777	3301	2984	2512
sc03 . p07	4185	3819	2890	3413	3097	2599
sc03 . p08	3778	3493	2667	3238	2909	2448
sc03 . p09	4009	3706	2797	3256	2909	2488

Input Data. Thermal and hydro parameters



* thermal generation

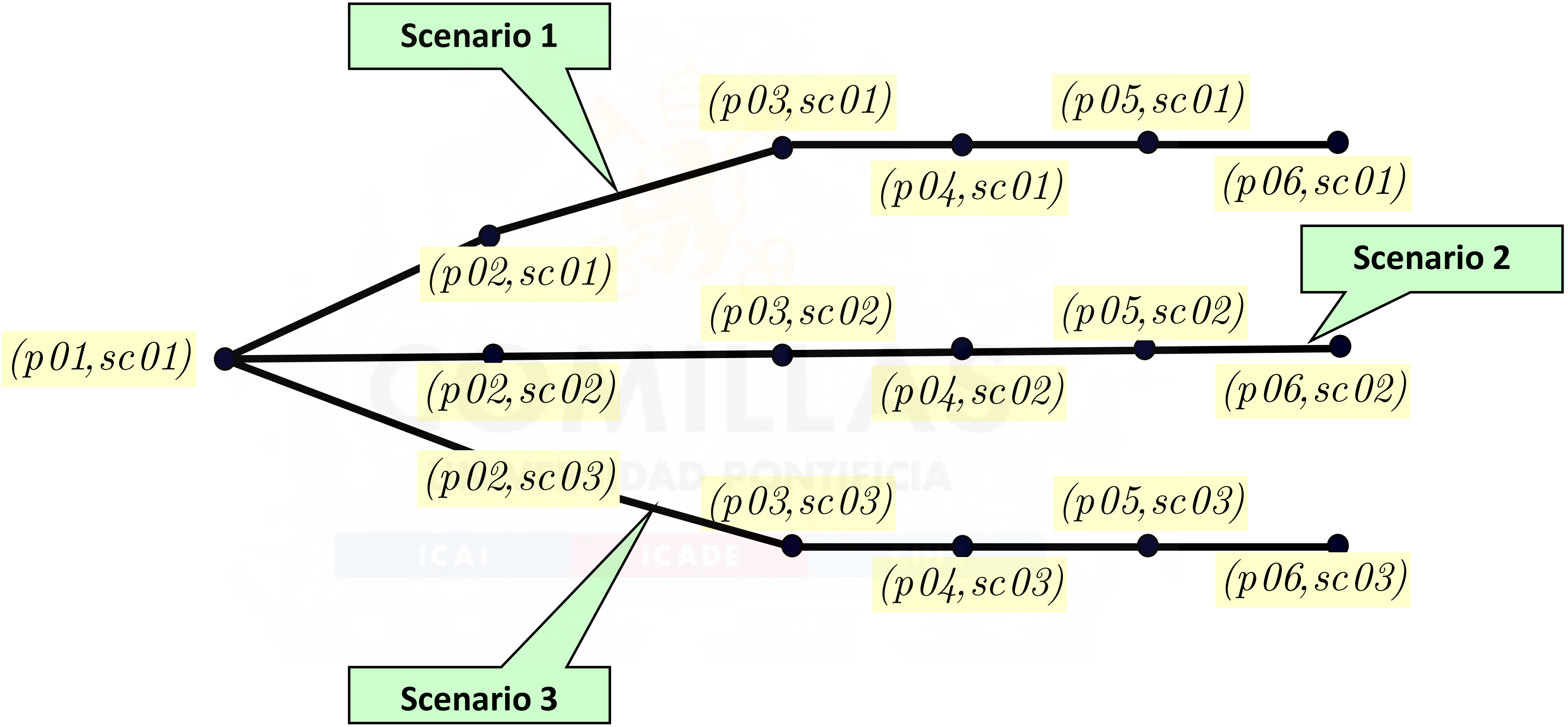
*	MaxProd [MW]	MinProd [MW]	FuelCost [€/Mcal]	SlopeVarCost [Mcal/MWh]	InterVarCost [Mcal/h]	OMVarCost [€/MWh]	StartupCost [Mcal]	EFOR [p.u.]	Aux [€/MWh]
Nuclear	771.6	771.6	1.00	15				0.00	15.00
DomesticCoal_Anthracite	588.0	235.2	0.02	2400	50000	6	2000000	0.00	49.70
BrownLignite	203.1	81.2	0.02	2300	50000	6	2000000	0.00	50.92
ImportedCoal_SubBituminous	150.4	60.2	0.02	2300	50000	6	2000000	0.00	52.65
ImportedCoal_Bituminous	194.4	77.8	0.02	2200	50000	6	2000000	0.00	49.14
CCGT_1	500.0	100.0	0.03	800	300000	6	1000000	0.00	42.00
CCGT_2	500.0	100.0	0.03	900	300000	4	1000000	0.00	45.00
CCGT_3	500.0	100.0	0.03	1000	300000	4	1000000	0.00	48.00
CCGT_4	667.5	133.5	0.03	800	300000	4	1000000	0.00	37.48
OCGT_1	400.0		0.03	2000	100000	4		0.00	67.50
OCGT_2	400.0		0.03	2100	100000	4		0.00	70.50
OCGT_3	400.0		0.03	2200	100000	4		0.00	73.50
FuelOilGas	441.8		0.06	2000	300000	3	1000000	0.00	160.74

* hydro generation

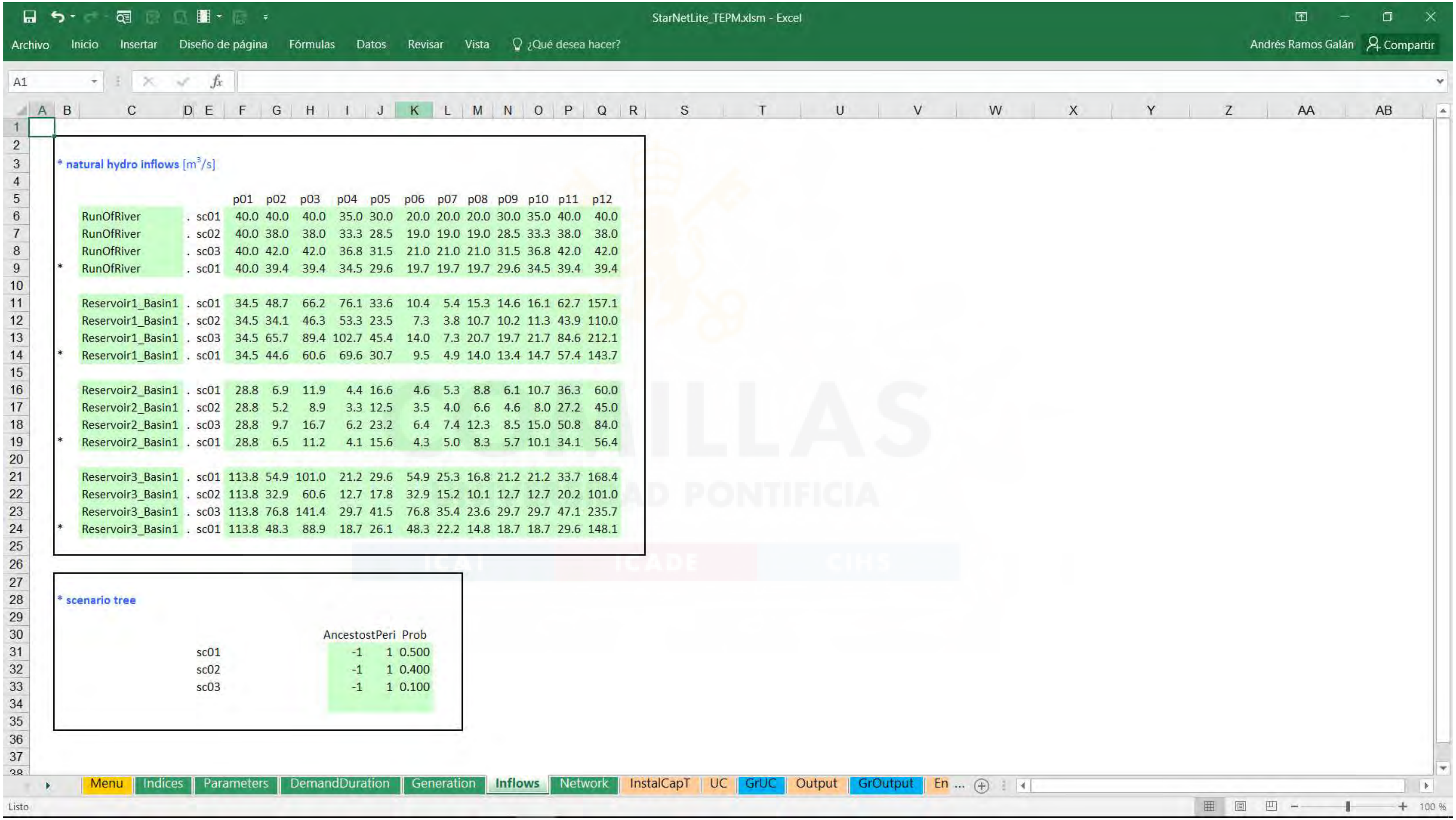
*	MaxProd [MW]	MinProd [MW]	ProdFunct [kWh/m^3]	Efficiency [p.u.]	MaxCons [MW]
RunOfRiver	150.0				
StorageHydro1_Basin1	200.0		0.30		
StorageHydro2_Basin1	200.0		0.30		
StorageHydro3_Basin1	200.0		0.30		
PumpedStorageHydro	200.0			0.70	200.0

* reservoir

Scenario tree



Input Data. Inflows



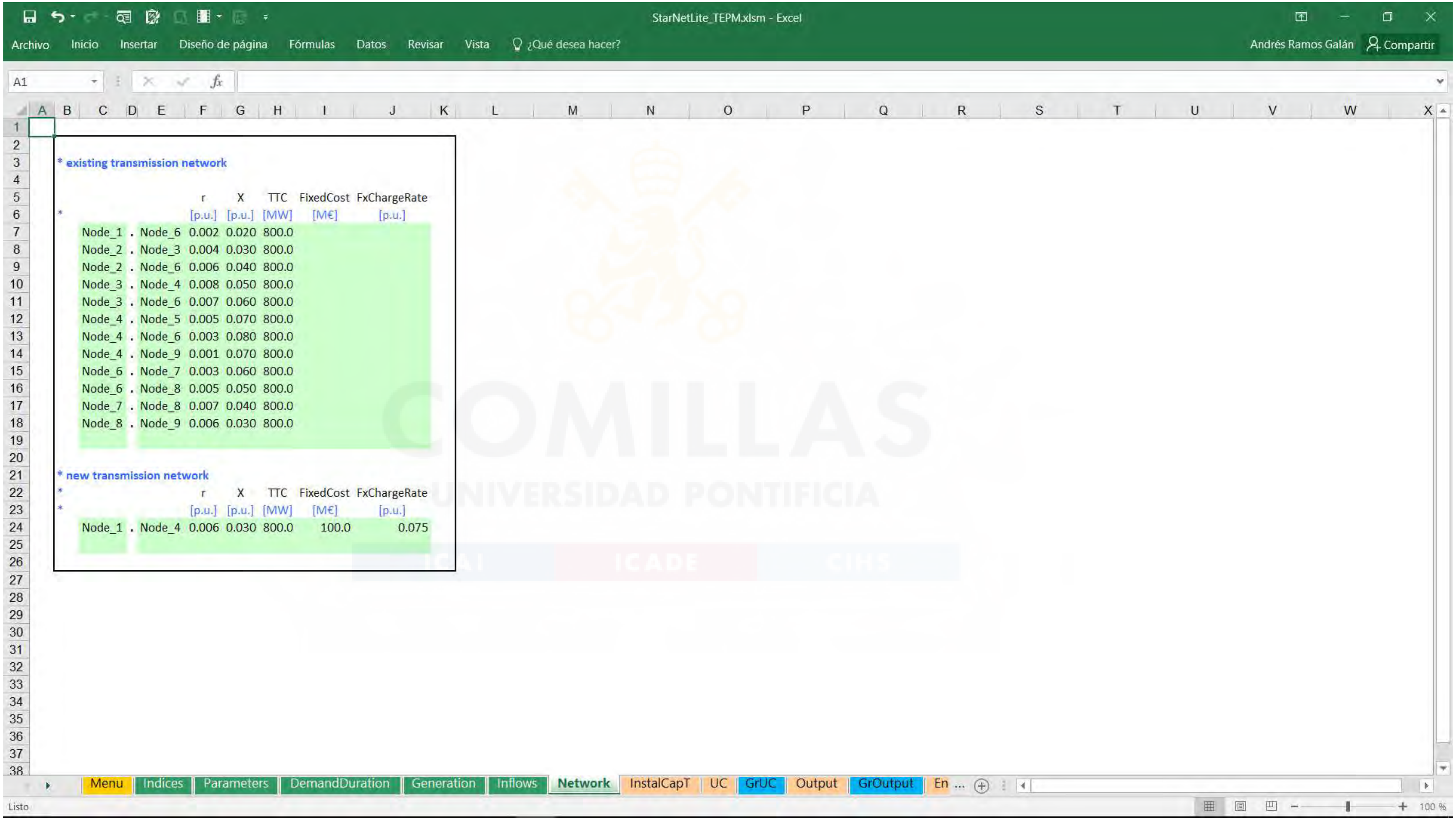
*** natural hydro inflows** [m³/s]

				p01	p02	p03	p04	p05	p06	p07	p08	p09	p10	p11	p12
	RunOfRiver	.	sc01	40.0	40.0	40.0	35.0	30.0	20.0	20.0	20.0	30.0	35.0	40.0	40.0
	RunOfRiver	.	sc02	40.0	38.0	38.0	33.3	28.5	19.0	19.0	19.0	28.5	33.3	38.0	38.0
	RunOfRiver	.	sc03	40.0	42.0	42.0	36.8	31.5	21.0	21.0	21.0	31.5	36.8	42.0	42.0
*	RunOfRiver	.	sc01	40.0	39.4	39.4	34.5	29.6	19.7	19.7	19.7	29.6	34.5	39.4	39.4
	Reservoir1_Basin1	.	sc01	34.5	48.7	66.2	76.1	33.6	10.4	5.4	15.3	14.6	16.1	62.7	157.1
	Reservoir1_Basin1	.	sc02	34.5	34.1	46.3	53.3	23.5	7.3	3.8	10.7	10.2	11.3	43.9	110.0
	Reservoir1_Basin1	.	sc03	34.5	65.7	89.4	102.7	45.4	14.0	7.3	20.7	19.7	21.7	84.6	212.1
*	Reservoir1_Basin1	.	sc01	34.5	44.6	60.6	69.6	30.7	9.5	4.9	14.0	13.4	14.7	57.4	143.7
	Reservoir2_Basin1	.	sc01	28.8	6.9	11.9	4.4	16.6	4.6	5.3	8.8	6.1	10.7	36.3	60.0
	Reservoir2_Basin1	.	sc02	28.8	5.2	8.9	3.3	12.5	3.5	4.0	6.6	4.6	8.0	27.2	45.0
	Reservoir2_Basin1	.	sc03	28.8	9.7	16.7	6.2	23.2	6.4	7.4	12.3	8.5	15.0	50.8	84.0
*	Reservoir2_Basin1	.	sc01	28.8	6.5	11.2	4.1	15.6	4.3	5.0	8.3	5.7	10.1	34.1	56.4
	Reservoir3_Basin1	.	sc01	113.8	54.9	101.0	21.2	29.6	54.9	25.3	16.8	21.2	21.2	33.7	168.4
	Reservoir3_Basin1	.	sc02	113.8	32.9	60.6	12.7	17.8	32.9	15.2	10.1	12.7	12.7	20.2	101.0
	Reservoir3_Basin1	.	sc03	113.8	76.8	141.4	29.7	41.5	76.8	35.4	23.6	29.7	29.7	47.1	235.7
*	Reservoir3_Basin1	.	sc01	113.8	48.3	88.9	18.7	26.1	48.3	22.2	14.8	18.7	18.7	29.6	148.1

*** scenario tree**

	AncestostPeri		Prob
sc01	-1	1	0.500
sc02	-1	1	0.400
sc03	-1	1	0.100

Input Data. Existing and candidate lines



* existing transmission network

			r	X	TTC	FixedCost	FxChargeRate
*			[p.u.]	[p.u.]	[MW]	[M€]	[p.u.]
Node_1	.	Node_6	0.002	0.020	800.0		
Node_2	.	Node_3	0.004	0.030	800.0		
Node_2	.	Node_6	0.006	0.040	800.0		
Node_3	.	Node_4	0.008	0.050	800.0		
Node_3	.	Node_6	0.007	0.060	800.0		
Node_4	.	Node_5	0.005	0.070	800.0		
Node_4	.	Node_6	0.003	0.080	800.0		
Node_4	.	Node_9	0.001	0.070	800.0		
Node_6	.	Node_7	0.003	0.060	800.0		
Node_6	.	Node_8	0.005	0.050	800.0		
Node_7	.	Node_8	0.007	0.040	800.0		
Node_8	.	Node_9	0.006	0.030	800.0		

* new transmission network

			r	X	TTC	FixedCost	FxChargeRate
*							
*			[p.u.]	[p.u.]	[MW]	[M€]	[p.u.]
Node_1	.	Node_4	0.006	0.030	800.0	100.0	0.075

StarNetLite_TEPM (i)

```
$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
   scp  (sc,p   ) tree defined as scenario and period
   scscp(sc,p,sc) ancestor        sc2    of node (sc1 p)
   scsch(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
   rur(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,ni,nf)
```

StarNetLite_TEPM (iii)

```
parameters
   pDemand     (  sc,      p,s,n) hourly load by node            [GW]
   pDemShare   (     nd         ) demand share                   [p.u.]
   pOperReserve(  sc,      p,s,n) hourly operating reserve       [GW]
   pDuration   (           p,s,n) duration                       [h]
   pCommitt    (y,sc,g,    p,s  ) commitment of the unit         [0-1]
   pProduct    (y,sc,g,    p,s,n) production of the unit         [MW]
   pEnergy     (y,sc,g,    p,s,n) energy     of the unit         [MWh]
   pLRMC       (y,sc,nd,   p,s,n) long run marginal cost         [€ per MWh]
   pReserve    (y,sc,r,    p    ) reservoir level                [hm3]
   pWValue     (y,sc,r,    p    ) water value                    [M€ per hm3]
   pFlow       (y,sc,nd,nd,p,s,n) flow                           [MW]
   pTheta      (y,sc,nd,   p,s,n) voltage angle                  [rad]

   pInstalCapT (nd,nd,y)          TEP investment decision        [0-1]

   pDemIncr     (y)                   yearly demand increase     [p.u.]
   pCumDemIncr  (y)               cum yearly demand increase     [p.u.]
   pOrder       (y)               ordinal of the year

   pEFOR        (g)               EFOR                           [p.u.]
   pMaxProd     (g)               maximum output                 [GW]
   pMinProd     (g)               minimum output                 [GW]
   pMaxCons     (g)               maximum consumption            [GW]
   pSlopeVarCost(g)               slope     variable cost        [M€ per GWh]
   pInterVarCost(g)               intercept variable cost        [M€ per   h]
   pStartupCost (g)               startup            cost        [M€]
   pMaxReserve  (r)               maximum reserve                [km3]
   pMinReserve  (r)               minimum reserve                [km3]
   pIniReserve  (r)               initial reserve                [km3]
   pProdFunct   (g)               production function            [GWh per km3]
   pEffic       (g)               pumping efficiency             [p.u.]
   pInflows     (r,sc,p)          inflows                        [km3]
   pENSCost                       energy non-served cost         [M€ per GWh]
   pPNSCost                       power  non-served cost         [M€ per GW ]

   pProbsc        (sc,p)          probability of a given period

   pR           (nd,nd)           line resistance                [p.u.]
   pX           (nd,nd)           line reactance                 [p.u.]
   pTTC         (nd,nd)           total transfer capacity        [GW]
   pFixedCost   (nd,nd)                     fixed     cost       [M€]

   pSbase                         base power                     [GW]

   lag(p)                         backward counting of period
   scaux                          scenario number
```

StarNetLite_TEPM (iv)

```
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)   installation decision in year y  [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]
   vWtReserve(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   )   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,nd)   max flow by installed capacity   [GW]
   eInstlCap2(y,sc,p,s,n,nd,nd)   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]
   eStrtUpPer(y,sc,p,s,  g)       unit startup    in same period
   eStrtUpNxt(y,sc,p,s,  g)       unit startup    in next period
   eWtReserve(y,sc,p,     r)      water reserve                    [km3] ;
```

StarNetLite_TEPM (v)

```
* mathematical formulation

eTotalTCost    .. vTotalTCost =e= vTotalFCost + vTotalVCost ;

eTotalFCost    .. vTotalFCost =e= sum[(y,lc), pFixedCost(lc)*vCumInstDc(y,lc)] ;

eTotalVCost    .. vTotalVCost =e= sum[(y,spsn(sc,p ,s,n),nd), pProbSc(sc,p)*pDuration(p,s,n)*pENSCost        *vENS    (y,sc,p,s,n,nd)] +
                                  sum[(y,scp (sc,p),s      ), pProbSc(sc,p)                 *pPNSCost        *vPNS    (y,sc,p,s     )] +
                                  sum[(y,scp (sc,p),s,   t ), pProbSc(sc,p)                 *pStartupCost (t)*vStartup(y,sc,p,s,  t )] +
                                  sum[(y,spsn(sc,p ,s,n),t ), pProbSc(sc,p)*pDuration(p,s,n)*pInterVarCost(t)*vCommitt(y,sc,p,s,  t )] +
                                  sum[(y,spsn(sc,p ,s,n),t ), pProbSc(sc,p)*pDuration(p,s,n)*pSlopeVarCost(t)*vProduct(y,sc,p,s,n,t )] ;

eOpReserve(y,spsn(sc,p,s,n1(n)         )) $pOperReserve(sc,p,s,n) .. sum[t,   pMaxProd(t)*vCommitt(y,sc,p,s,  t)] + sum[h,         pMaxProd(           h)] + vPNS(y,sc,p,s     ) =g= [pDemand(sc,p,s,n) + pOperReserve(sc,p,s,n)] *
pCumDemIncr(y) ;
eBalance  (y,spsn(sc,p,s,   n),   nd    )                         .. sum[gnd(g,nd),       vProduct(y,sc,p,s,n,g)] - sum[gnd(h,nd), vConsump(y,sc,p,s,n,h)] + vENS(y,sc,p,s,n,nd) =e=  pDemand(sc,p,s,n) * pDemShare(nd)           *
pCumDemIncr(y) +
                                                                     sum[la(nd,nf), vFlow(y,sc,p,s,n,nd,nf)] - sum[la(ni,nd), vFlow(y,sc,p,s,n,ni,nd)] + vLosses(y,spsn,nd) ;

eInstlCapC(ly(y),lc          )            .. vCumInstDc(y,lc) =l= vCumInstDc(y+1,lc) ;

eInstlCap1(y,spsn(sc,p,s,   n),lc(ni,nf)) .. vFlow(y,sc,p,s,n,ni,nf) /     pTTC(ni,nf) =g=                                                                                             - vCumInstDc(y,ni,nf) ;
eInstlCap2(y,spsn(sc,p,s,   n),lc(ni,nf)) .. vFlow(y,sc,p,s,n,ni,nf) /     pTTC(ni,nf) =l=                                                                                               vCumInstDc(y,ni,nf) ;
eFlowNetN1(y,spsn(sc,p,s,   n),lc(ni,nf)) .. vFlow(y,sc,p,s,n,ni,nf) / 1e3*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,spsn(sc,p,s,   n),lc(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) ;
eFlowNetEx(y,spsn(sc,p,s,   n),le(ni,nf)) .. vFlow(y,sc,p,s,n,ni,nf)                   =e= [vTheta(y,sc,p,s,n,ni) - vTheta(y,sc,p,s,n,nf)] * pSbase / pX(ni,nf)                                               ;

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

eMaxOutput(y,spsn(sc,p,s,n),t) $pMaxProd(t) .. vProduct(y,sc,p,s,n,t) / pMaxProd(t) =l= vCommitt(y,sc,p,s,t) ;
eMinOutput(y,spsn(sc,p,s,n),t) $pMinProd(t) .. vProduct(y,sc,p,s,n,t) / pMinProd(t) =g= vCommitt(y,sc,p,s,t) ;

eProdctPer(y,spsn(sc,p,s1(s),n),g) .. vProduct(y,sc,p,s+1,n,g) =l= vProduct(y,sc,p,s,n,g) ;

eStrtUpPer(y,scp(sc,p),s1(s),t) $[card(s) > 1              ] .. vCommitt(y,sc,p,s+1,t) =g=                      vCommitt(y,sc ,p  ,s  ,t)  + vStartup(y,sc,p,s+1,t) - vShutdown(y,sc,p,s+1,t) ;
eStrtUpNxt(y,scp(sc,p),s1(s),t) $[card(s) > 1 and not p1(p)] .. vCommitt(y,sc,p,s  ,t) =g= sum[scscp(sc,p,scc), vCommitt(y,scc,p-1,s+1,t)] + vStartup(y,sc,p,s  ,t) - vShutdown(y,sc,p,s  ,t) ;

eWtReserve(y,scp(sc,p),      r) .. sum[scscp(sc,p,scc), vWtReserve(y,scc,p-1,r)] + pIniReserve(r) $p1(p) - vWtReserve(y,sc,p,r) +
                                   pInflows(r,sc,p) - vSpillage(y,sc,p,r) + sum[rur(rr,r), vSpillage(y,sc,p,rr)]  +
                                   sum{(s,n), pDuration(p,s,n)*sum[hur(h,r), vProduct(y,sc,p,s,n,h)/pProdFunct(h)]} -
                                   sum{(s,n), pDuration(p,s,n)*sum[ruh(r,h), vProduct(y,sc,p,s,n,h)/pProdFunct(h)]} +
                                   sum{(s,n), pDuration(p,s,n)*sum[hpr(h,r), vConsump(y,sc,p,s,n,h)/pProdFunct(h)*pEffic(h)]} -
                                   sum{(s,n), pDuration(p,s,n)*sum[rph(r,h), vConsump(y,sc,p,s,n,h)/pProdFunct(h)*pEffic(h)]} =e= 0 ;

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

StarNetLite_TEPM (vi)

```
* read input data from Excel and include into the model

file TMP / tmp_%gams.user1%.txt /
$OnEcho  > tmp_%gams.user1%.txt
   r1=    indices
   o1=tmp_indices.txt
   r2=    param
   o2=tmp_param.txt
   r3=    demand
   o3=tmp_demand.txt
   r4=    oprres
   o4=tmp_oprres.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 m i="%gams.user1%.xlsm" @"tmp_%gams.user1%.txt"
$else.OptSkipExcelInput
$  log Excel input skipped
$endif.OptSkipExcelInput

sets
$include tmp_indices.txt
;
$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
;

* 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_oprres.txt tmp_duration.txt tmp_thermalgen.txt tmp_hydrogen.txt tmp_reservoir.txt tmp_inflows.txt tmp_tree.txt
tmp_network.txt' ;
```

StarNetLite_TEPM (vii)

```
* determine the first and last period and the first subperiod

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

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

t (g) $[pThermalGen(g,'MaxProd'   ) and pThermalGen(g,'FuelCost')] = yes ;
h (g) $[pHydroGen  (g,'MaxProd'   )                              ] = yes ;
rs(r) $[pReservoir (r,'MaxReserve') > 0                          ] = yes ;

* compute the cumulative yearly demand growth

ly(y) $[ord(y) < card(y)] = yes ;
z          (y)            = yes ;
pOrder     (y) = ord(y) ;
pCumDemIncr(y) = prod[z $[pOrder(z) <= ord(y)], 1+pDemIncr(z)] ;
```

StarNetLite_TEPM (viii)

```
* scaling of parameters

pDemand     (sc,p,s,n) = pDemand     (sc,p,s,n)       * 1e-3 ;
pOperReserve(sc,p,s,n) = pOperReserve(sc,p,s,n)       * 1e-3 ;
pENSCost               = pENSCost                     * 1e-3 ;
pPNSCost               = pPNSCost                     * 1e-3 ;

pEFOR        (t)    = pThermalGen(t,'EFOR'         )        ;
pMaxProd     (t)    = pThermalGen(t,'MaxProd'      ) * 1e-3 * [1-pEFOR(t)] ;
pMinProd     (t)    = pThermalGen(t,'MinProd'      ) * 1e-3 * [1-pEFOR(t)] ;
pSlopeVarCost(t)    = pThermalGen(t,'OMVarCost'    ) * 1e-3 +
                      pThermalGen(t,'SlopeVarCost' ) * 1e-3 * pThermalGen(t,'FuelCost') ;
pInterVarCost(t)    = pThermalGen(t,'InterVarCost' ) * 1e-6 * pThermalGen(t,'FuelCost') ;
pStartupCost (t)    = pThermalGen(t,'StartupCost'  ) * 1e-6 * pThermalGen(t,'FuelCost') ;

pMaxProd     (h)    = pHydroGen  (h,'MaxProd'      ) * 1e-3 ;
pMinProd     (h)    = pHydroGen  (h,'MinProd'      ) * 1e-3 ;
pMaxCons     (h)    = pHydroGen  (h,'MaxCons'      ) * 1e-3 ;
pProdFunct   (h)    = pHydroGen  (h,'ProdFunct'    ) * 1e+3 ;
pEffic       (h)    = pHydroGen  (h,'Efficiency'   )        ;
pMaxReserve  (r)    = pReservoir (r,'MaxReserve'   ) * 1e-3 ;
pMinReserve  (r)    = pReservoir (r,'MinReserve'   ) * 1e-3 ;
pIniReserve  (r)    = pReservoir (r,'IniReserve'   ) * 1e-3 ;

pInflows(r,sc,p)    = pInflows   (r,sc,p            ) * 1e-6 * 3.6*sum[(s,n), pDuration(p,s,n)] ;

pR        (ni,nf)   = pNetwork   (ni,nf,'R'         )        ;
pX        (ni,nf)   = pNetwork   (ni,nf,'X'         )        ;
pTTC      (ni,nf)   = pNetwork   (ni,nf,'TTC'       ) * 1e-3 ;
pFixedCost(ni,nf)   = pNetwork   (ni,nf,'FixedCost') * pNetwork(ni,nf,'FxChargeRate') ;

pSbase              = pSbase                          * 1e-3 ;

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

la(   ni,nf ) $pX        (ni,nf)  = yes ;
lc(   ni,nf ) $pFixedCost(ni,nf)  = yes ;
le(la(ni,nf)) $[not    lc(ni,nf)] = yes ;

* 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

pProdFunct(h) $[pProdFunct(h) = 0] = 1e3 ;
pEffic    (h) $[pEffic    (h) = 0] =   1 ;
```

StarNetLite_TEPM (ix)

```
* bounds on variables

vProduct.up  (y,sc,p,s,n,g)    = pMaxProd(g)    ;
vConsump.up  (y,sc,p,s,n,g)    = pMaxCons(g)    ;

vPNS.up      (y,sc,p,s     )   = sum[n1(n), [pDemand(sc,p,s,n) + pOperReserve(sc,p,s,n)] * pCumDemIncr(y)] ;
vENS.up      (y,sc,p,s,n,nd)   =             pDemand(sc,p,s,n) * pDemShare(nd)          * pCumDemIncr(y)  ;

vWtReserve.up(y,sc,p,r)        = pMaxReserve(r) ;
vWtReserve.lo(y,sc,p,r)        = pMinReserve(r) ;
vWtReserve.fx(y,sc,p,r) $pn(p) = pIniReserve(r) ;

vFlow.lo     (y,sc,p,s,n,la)   = - pTTC(la) ;
vFlow.up     (y,sc,p,s,n,la)   =   pTTC(la) ;

* voltage angle of the reference node is fixed to 0

vTheta.fx  (y,sc,p,s,n,nd) $[ord(nd) = 1] = 0 ;
```

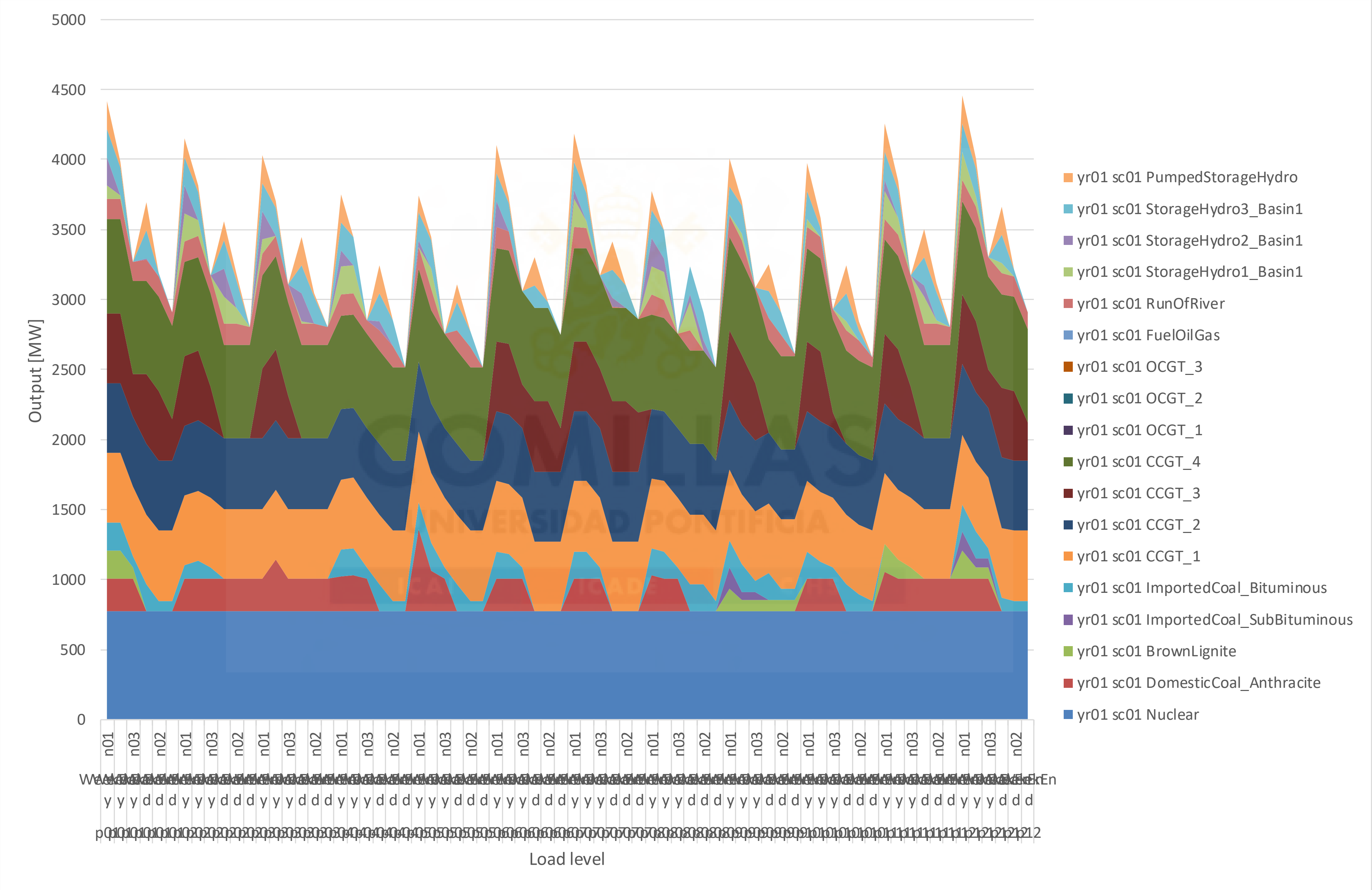
StarNetLite_TEPM (x)

```
* 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 ;
scscp(scp(sc,p),scc) $[ord(p) >  pScnTree(sc,'FirstPeriod') and ord(scc) = ord(sc)                ] = yes ;
scscp(scp(sc,p),scc) $[ord(p)  = pScnTree(sc,'FirstPeriod') and ord(scc) = pScnTree(sc,'Ancestor')] = yes ;
scsch(sc,scp(scc,p)) $scscp(scc,p,sc)                                                               = yes ;

pProbSc(sc,pn(p)) = pScnTree(sc,'Prob')/sum[scc, pScnTree(scc,'Prob')] ;
loop (p $[not p1(p)],
   pProbSc(scp(sc,p+lag(p))) = sum[scsch(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 ;
scscp(    sc,p ,scc) $[pProbSc(sc,p) = 0 or pProbSc(scc,p-1) = 0] =  no ;
scsch(sc,scc,p     )                                              = yes $scscp(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

loop (sc $sum[p, pProbSc(sc,p)],
   scaux = ord(sc) ;
   loop (p,
      scscr(sc,p+lag(p),scc) $[ord(scc) = scaux] = yes ;
      SCA(scc)               $[ord(scc) = scaux] = yes ;
      scaux = sum[scscp(sca,p+lag(p),scc), ord(scc)] ;
      SCA(scc)                                   =  no ;
   ) ;
) ;
SCA(sc) $sum[p, pProbSc(sc,p)] = yes ;
```

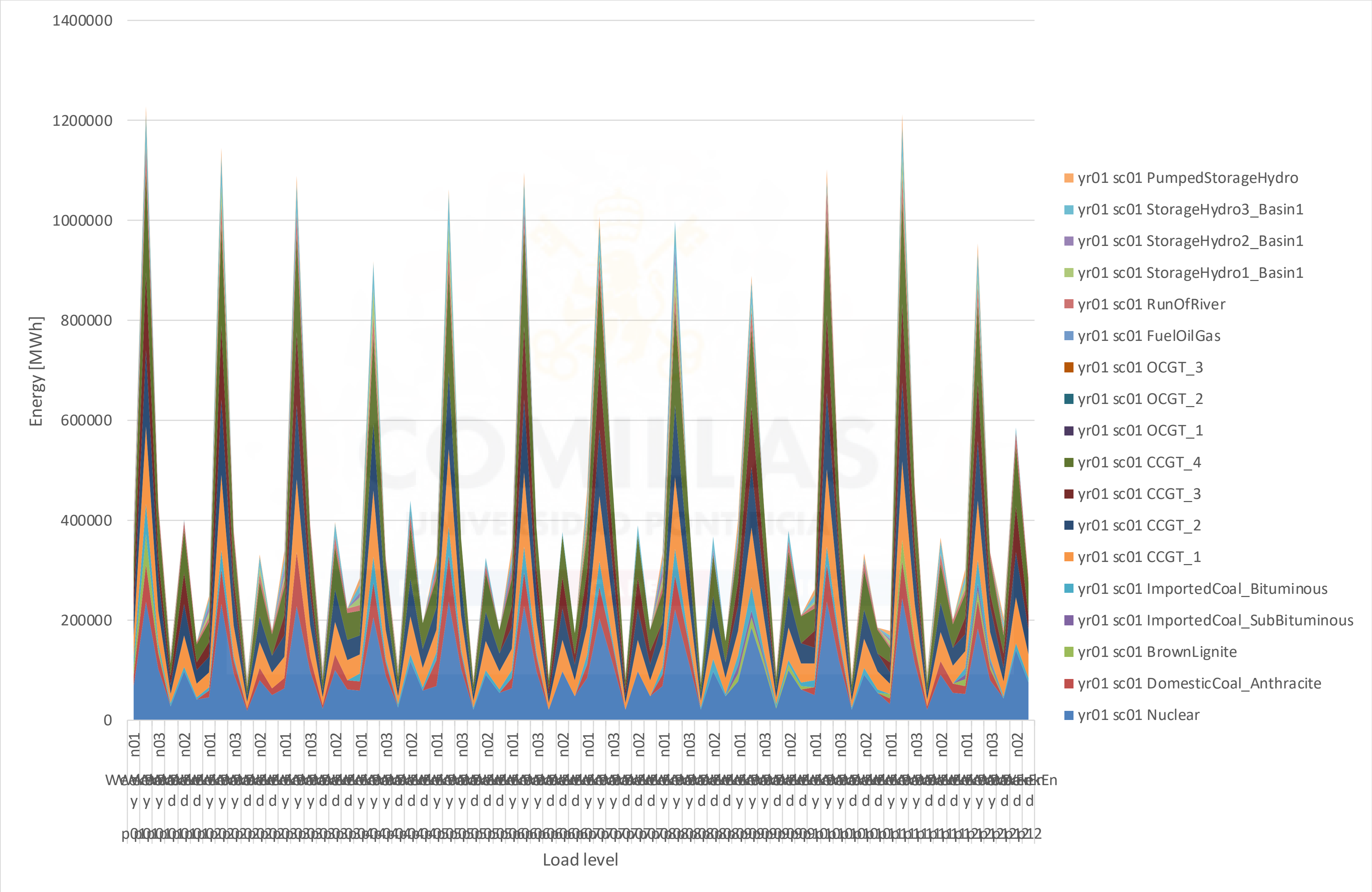
StarNetLite_TEPM (xi)

```
* solve transmission expansion planning model

solve mTEPM using MINLP minimizing vTotalTCost ;

* scaling of the results

pInstalCapT(lc,y)             =                                       vCumInstDc.l(y,          lc)                                                       + eps ;

pCommitt(y,sca,t,    p,s    ) = sum[scscr(sca,p,scc)                , vCommitt.l  (y,scc,p,s,  t )                                                 ]     + eps ;
pProduct(y,sca,g,psn(p,s,n) ) = sum[scscr(sca,p,scc)                , vProduct.l  (y,scc,p,s,n,g )                                                 ]*1e3 + eps ;
pEnergy (y,sca,g,psn(p,s,n) ) = sum[scscr(sca,p,scc)                , vProduct.l  (y,scc,p,s,n,g )                *pDuration(p,s,n)                ]*1e3 + eps ;
pReserve(y,sca,rs(r),p      ) = sum[scscr(sca,p,scc)                , vWtReserve.l(y,scc,p,    r )                                                 ]*1e3 + eps ;
pWValue (y,sca,rs(r),p      ) = sum[scscr(sca,p,scc) $pProbSc(scc,p), eWtReserve.m(y,scc,p,    r )/sum[psn(p,s,n), pDuration(p,s,n)]/pProbSc(scc,p)]*1e3 + eps ;
pFlow   (y,sca,la,psn(p,s,n)) = sum[scscr(sca,p,scc)                , vFlow.l     (y,scc,p,s,n,la)                                                 ]*1e3 + eps ;
pTheta  (y,sca,nd,psn(p,s,n)) = sum[scscr(sca,p,scc)                , vTheta.l    (y,scc,p,s,n,nd)                                                 ]     + eps ;
pLRMC   (y,sca,nd,psn(p,s,n)) = sum[scscr(sca,p,scc) $pProbSc(scc,p), eBalance.m  (y,scc,p,s,n,nd)                /pDuration(p,s,n) /pProbSc(scc,p)]*1e3 + eps ;

* data output to xls 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=pCommitt 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="Year"         rng=Output!a1' / 'text="Year"        rng=Energy!a1' / 'text="Year"         rng=WtrReserve!a1' / 'text="Year"        rng=WtrValue!a1' / 'text="Year"
rng=LRMC!a1' / 'text="Year"         rng=UC!a1' / 'text="Node"            rng=InstalCapT!a1' / 'text="Year"      rng=Flow!a1' / 'text="Year"       rng=Angle!a1' /
                 'text="Scen"         rng=Output!b1' / 'text="Scen"        rng=Energy!b1' / 'text="Scen"         rng=WtrReserve!b1' / 'text="Scen"        rng=WtrValue!b1' / 'text="Scen"
rng=LRMC!b1' / 'text="Scen"         rng=UC!b1' / 'text="Node"            rng=InstalCapT!b1' / 'text="Scen"      rng=Flow!b1' / 'text="Scen"       rng=Angle!b1' /
                 'text="Unit"         rng=Output!c1' / 'text="Unit"        rng=Energy!c1' / 'text="Reservoir"    rng=WtrReserve!c1' / 'text="Reservoir"   rng=WtrValue!c1' / 'text="Node"
rng=LRMC!c1' / 'text="Unit"         rng=UC!c1' /                                              'text="Node"      rng=Flow!c1' / 'text="Node"       rng=Angle!c1' /

'text="Node"      rng=Flow!d1' /
execute_unload   'tmp_%gams.user1%.gdx' pProduct pEnergy pReserve pWValue pLRMC pCommitt pInstalCapT pFlow pTheta
*$ifthen.OptSkipExcelOutput '%OptSkipExcelOutput%' == 0
execute          'gdxxrw tmp_"%gams.user1%".gdx SQ=n EpsOut=0 O=tmp_"%gams.user1%".xlsx @tmp_"%gams.user1%".txt'
execute          'del    tmp_"%gams.user1%".gdx                                                                '
*$else.OptSkipExcelOutput
*$  log Excel output skipped
*$endif.OptSkipExcelOutput
execute          'del                                                                    tmp_"%gams.user1%".txt'

$OnListing
```

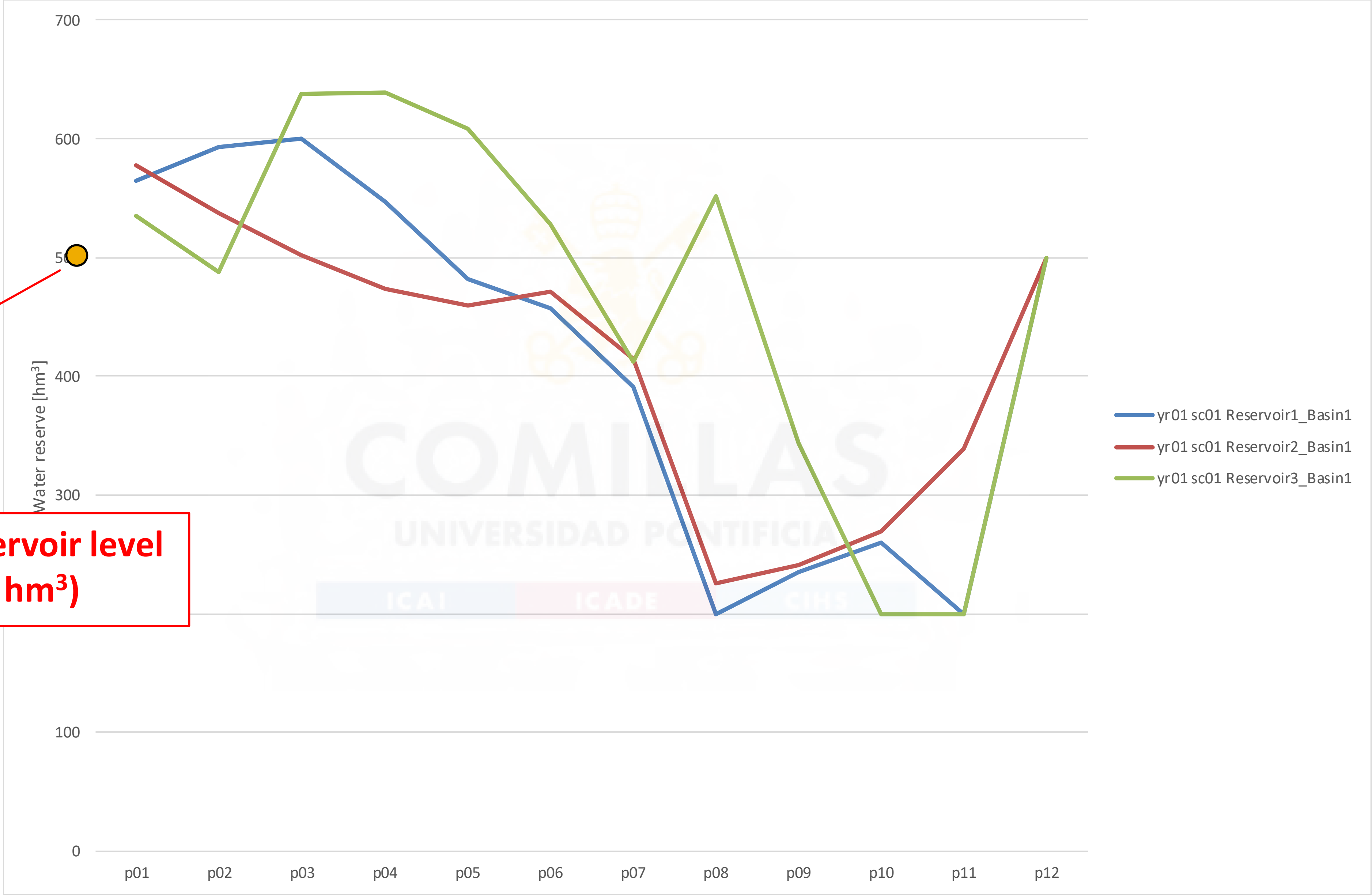
Output Data. Production for year 1



Output Data. Energy for year 1

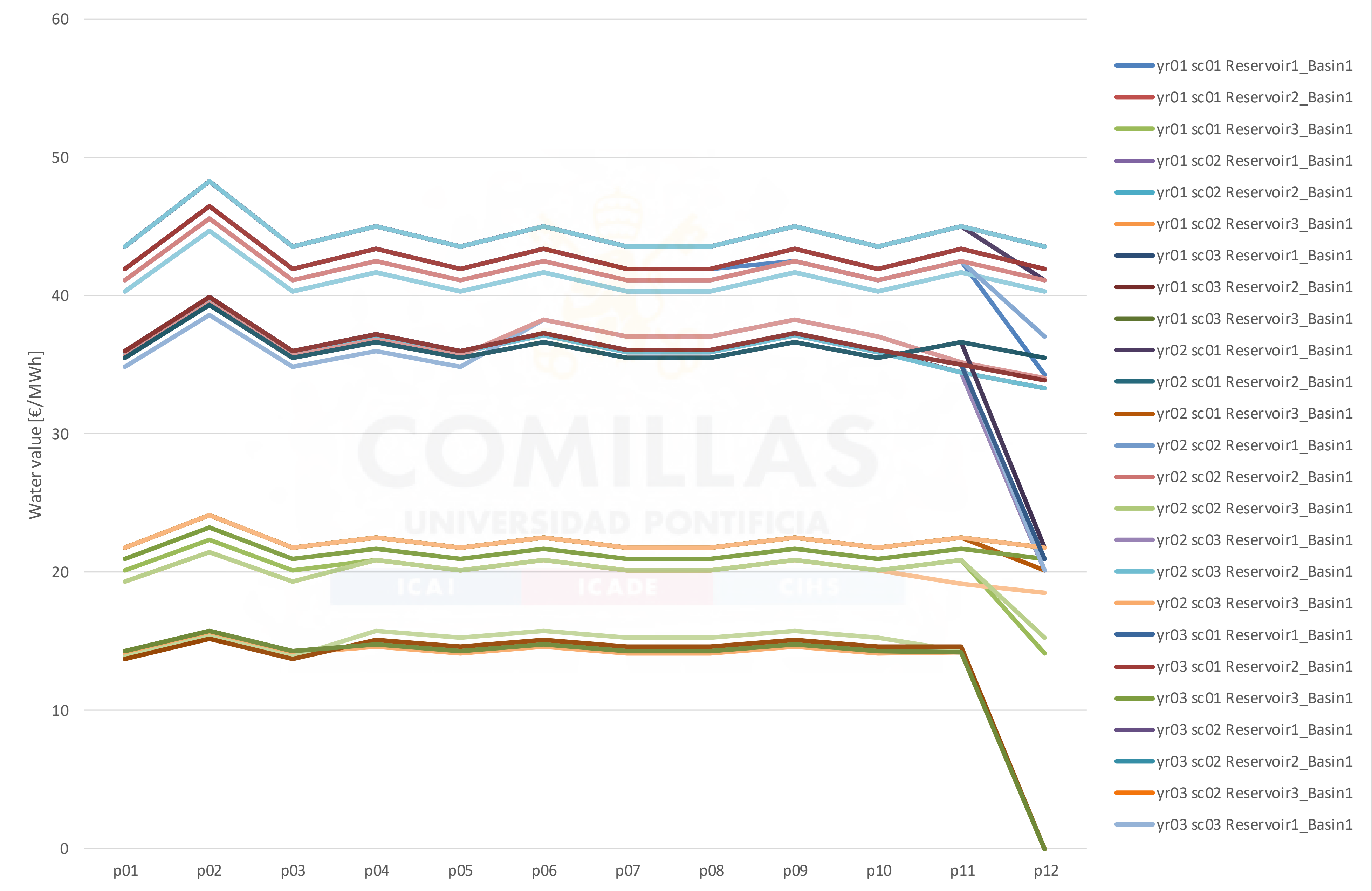


Output Data. Reservoir level for year 1

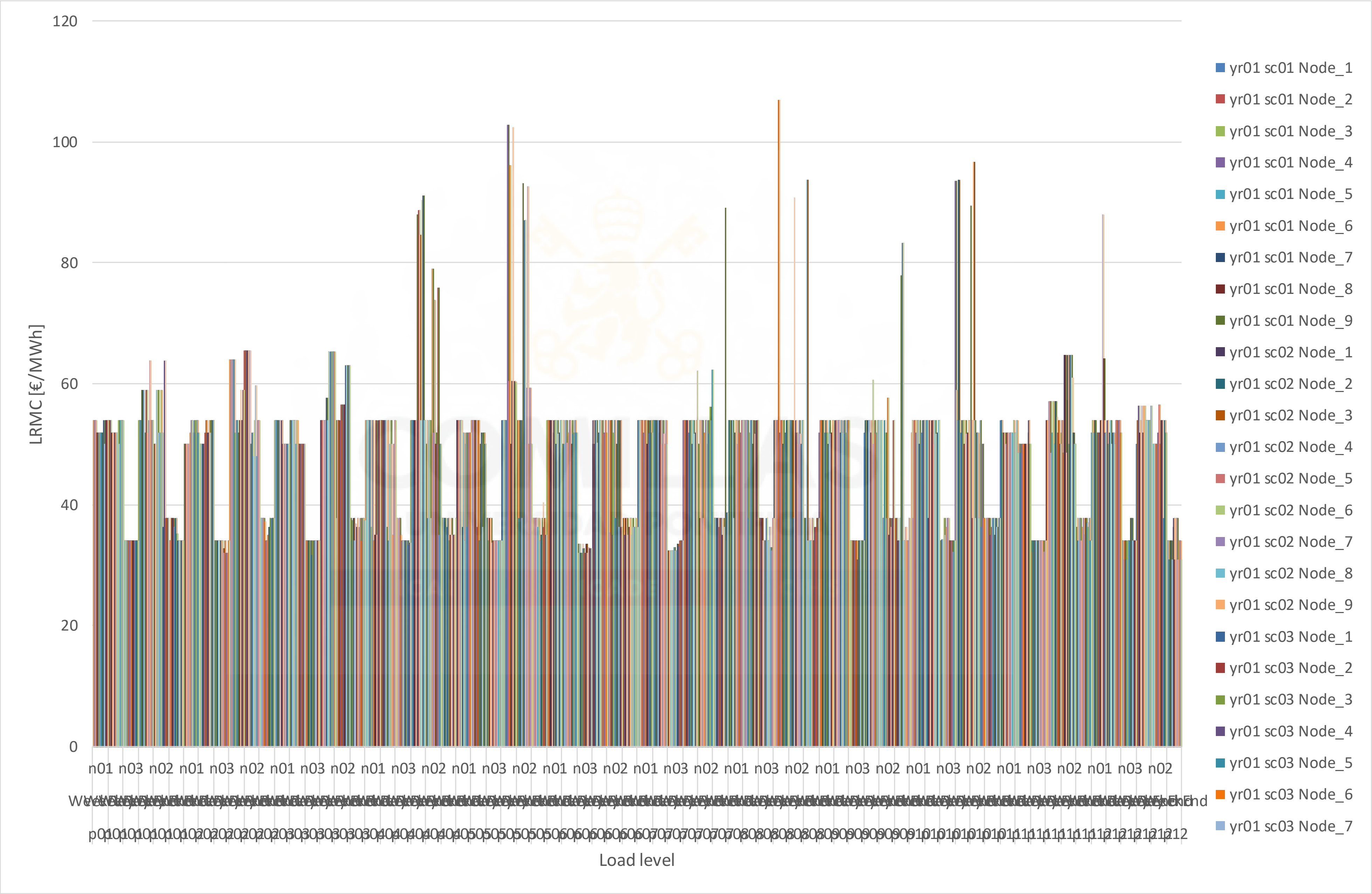


Initial reservoir level (500 hm^3)

Output Data. Water value for year 1



Output Data. Long Run Marginal Cost for year 1



If TEP model is solved with binary investment decisions no marginal impact of those decisions is considered

1. Transmission Expansion Planning
2. Simple TEP models
3. Modeling issues
4. Prototype TEP. Mathematical formulation
5. Prototype TEP. Computer implementation
6. Takeaways

6

Takeaways

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 in this model
- Non-random and random uncertainties affecting the analysis
- Main criteria used to define the best alternatives
- Decision framed as an MCDM solved by the 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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