Modelling the Electricity Transmission Network with High Shares of Renewable Energy

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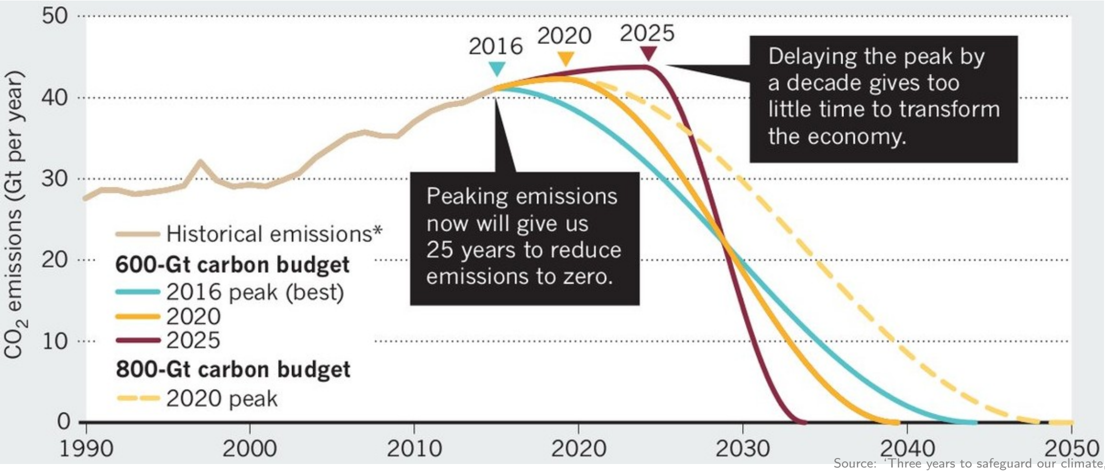
Table of Contents

The Challenges of Optimising a Renewable Energy System

The Societal Challenge

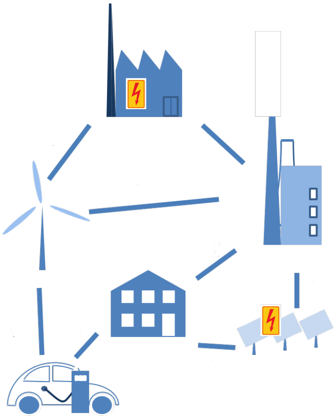
To avoid warming of more than 1.5-2 °C, we need to limit global CO_2 emissions to 600-800 Gt:



Source: 'Three years to safeguard our climate,' Nature, 2017

Energy System Design: Research Questions

- What **infrastructure** does a highly renewable energy system require and **where** should it go?
- Given a desired CO_2 reduction, how much will it **cost**?
- How to deal with the **variability** of wind and solar?
- What is the **trade-off** between **transmission**, **storage** and **sector-coupling**?



The answers to these questions affect **hundreds of billions** of euros of spending per year.

Researchers deal with these questions by solving large **optimisation** problems.

Take account of social and political constraints

The Energy Transition is not just a case of "cost optimisation under CO_2 constraints". There are also **social and political constraints**.

We need to assess:

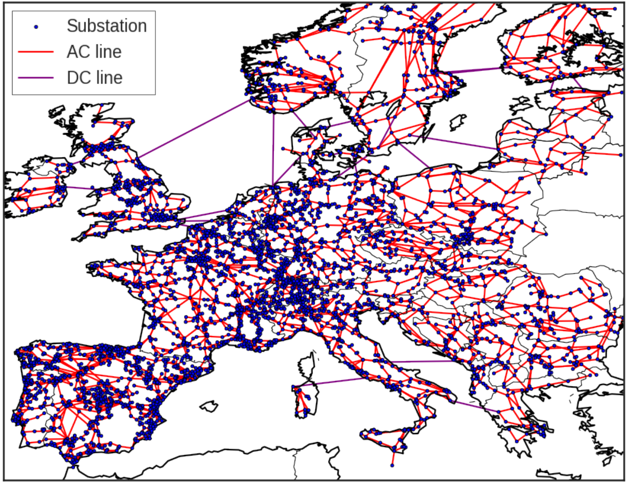
- Reducing need for transmission using **storage / sector coupling** (e.g. battery electric vehicles, thermal storage)
- **New technologies** that can minimise the landscape impact of transmission

Transparency is critical for public acceptance.

Problem 1: Spatial resolution

Need high **spatial resolution** to represent VRE variations and transmission constraints.

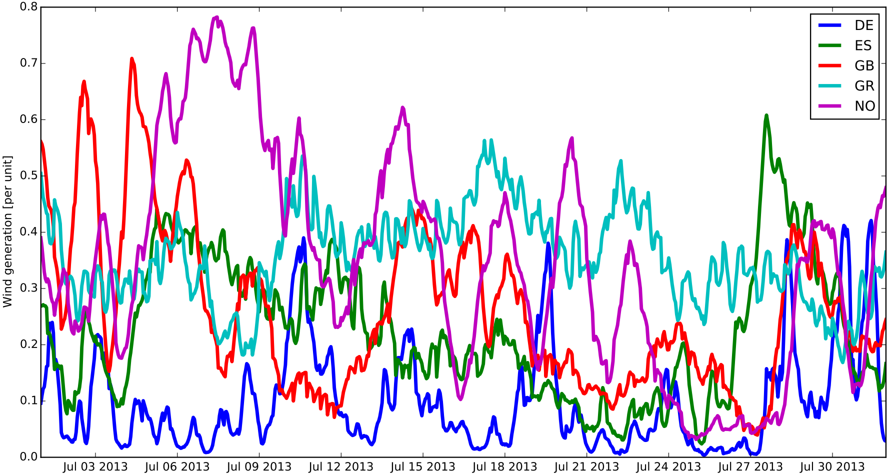
Network topology of the HV grid



Source: ENTSO-E

Problem 2: Temporal resolution

Need high **temporal resolution** to represent load and VRE resource variability, correlations and extreme events. Wind generation in Europe in July 2013:



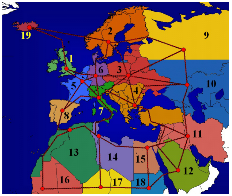
Problem 3: Model complexity

- Modelling must respect **physics**
- How much **detail** in the input data do we need?
- Optimise transmission **simultaneously** with generation capacity?
- Optimise electricity, heating and transport **together** (lots of **interdependencies**)?
- How bad are **linear approximations**?
- Can we make the **algorithms faster**, to add detail in other areas?
- By looking at static situations, do we miss **dynamic effects**?

Examples from literature of energy system optimisation

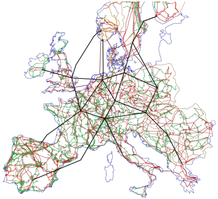
Study	Scope	Spatial resolution	Temporal resolution	What?	Flow physics
Czisch (2005)	MENA	low	high	electricity (gen and grid)	transport
Hagspiel et al. (2014)	EU	medium	low	electricity (gen and grid)	linear
Egerer et al. (2014)	EU	high	low	electricity (gen only)	linear
Fraunhofers ISE, IWES	DE	none	high	electricity, heating, transport	none

Czisch



Hagspiel et al.

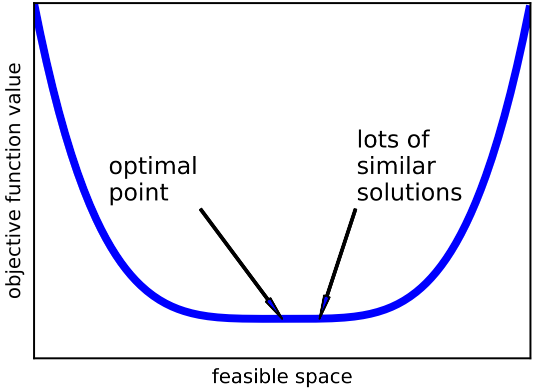
Egerer et al.



Problem 4: Understand Solution Space

How **sensitive** is our solution to changes in the inputs?

Researchers have focused in the past on **local** linear sensitivity, but it's also important to look at the **global behaviour** of the objective function on the feasible space, to understand where the costs increase the fastest.



Overarching goal

Find the **sweet spot** where:

- Computation time is finite (i.e. a week)
- Temporal resolution is "good enough"
- Spatial resolution is "good enough"
- Model detail is "good enough"

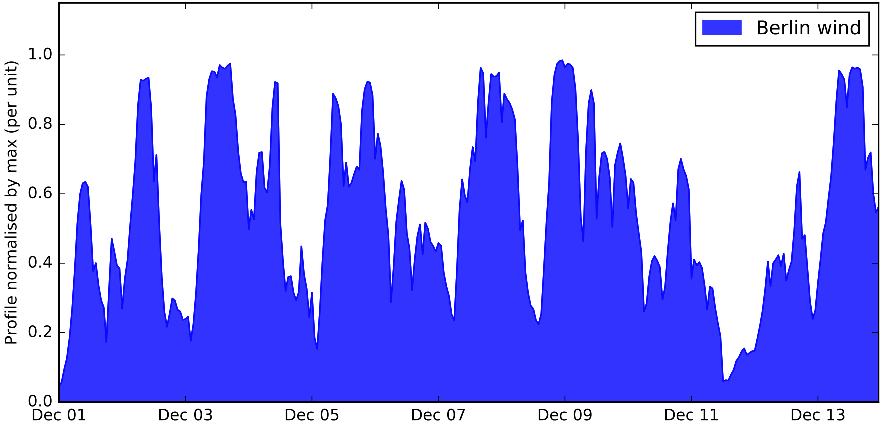
AND quantify the error we make by only being "good enough" (e.g. are important metrics $\pm 10\%$ or $\pm 50\%$ correct?)

AND be sure we're got a handle on all sectoral interdependencies that might affect the results.

Dealing with Renewable Spatio-Temporal Variability

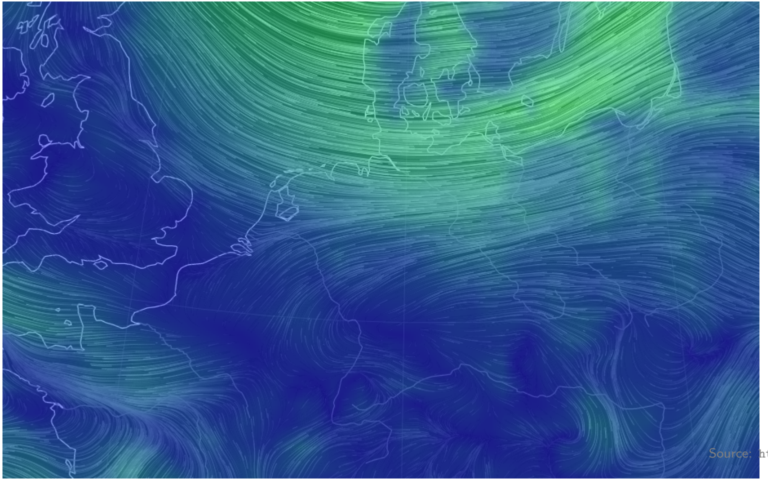
Variability: Single wind site in Berlin

Looking at the wind output of a single wind plant over two weeks, it is highly variable, frequently dropping close to zero and fluctuating strongly.



Variability: Different wind conditions over Germany

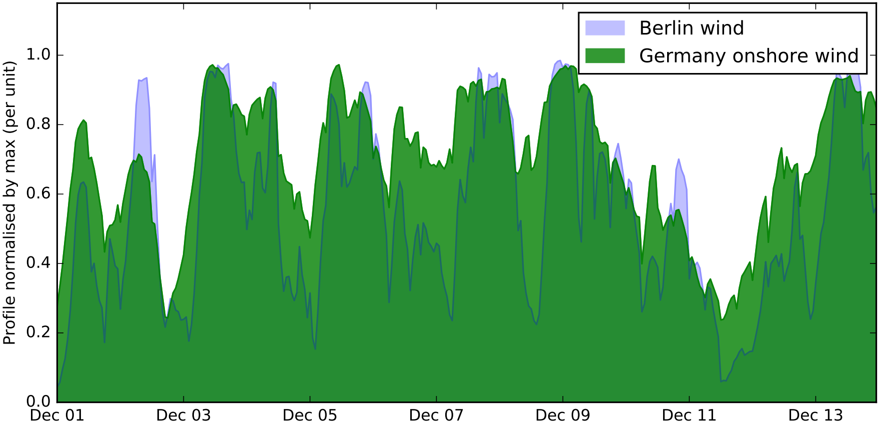
But the wind doesn't blow the same at every site at every time: at each time there are a variety of wind conditions across Germany. These differences **balance out over time and space**.



Source: https://earth.nullschool.net/

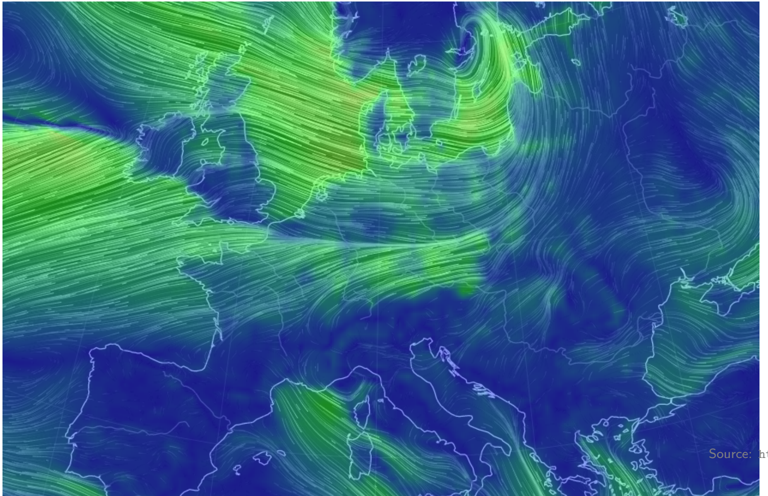
Variability: Single country: Germany

For a whole country like Germany this results in valleys and peaks that are somewhat smoother, but the profile still frequently drops close to zero.



Variability: Different wind conditions over Europe

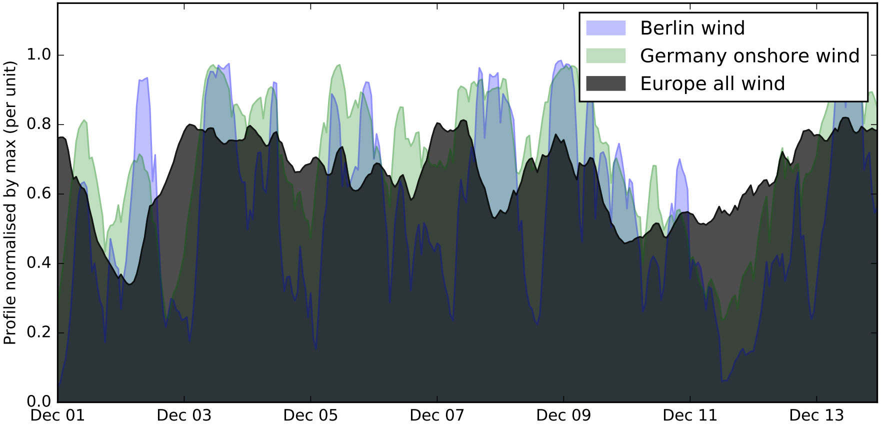
The scale of the weather systems are bigger than countries, so to leverage the full smoothing effects, you need to integrate wind at the **continental scale**.



Source: https://earth.nullschool.net/

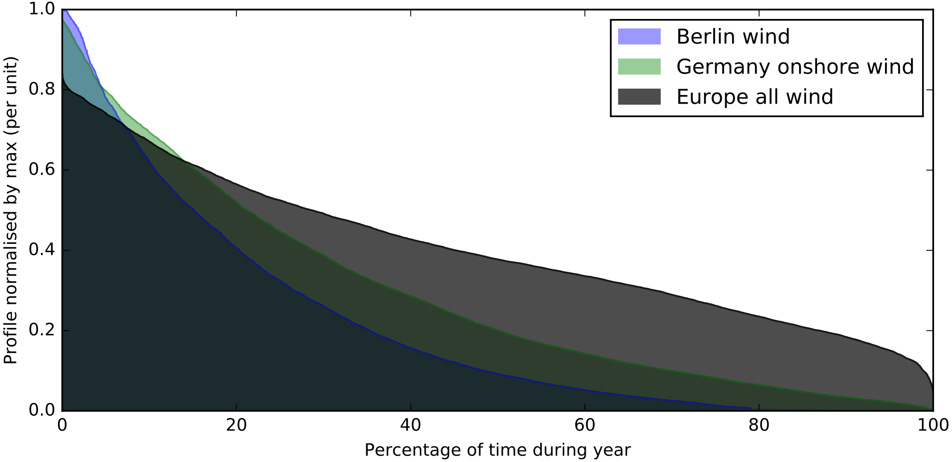
Variability: A continent: Europe

If we can integrate the feed-in of wind turbines across the European continent, the feed-in is considerably smoother: we've eliminated most valleys and peaks.



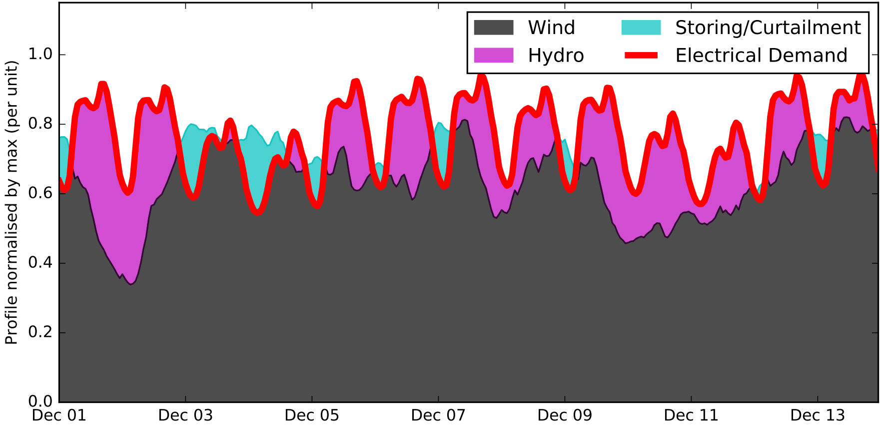
Smoothing in Europe versus Germany

Wind duration curve for Europe is more regular and less peaked than that for Germany alone.



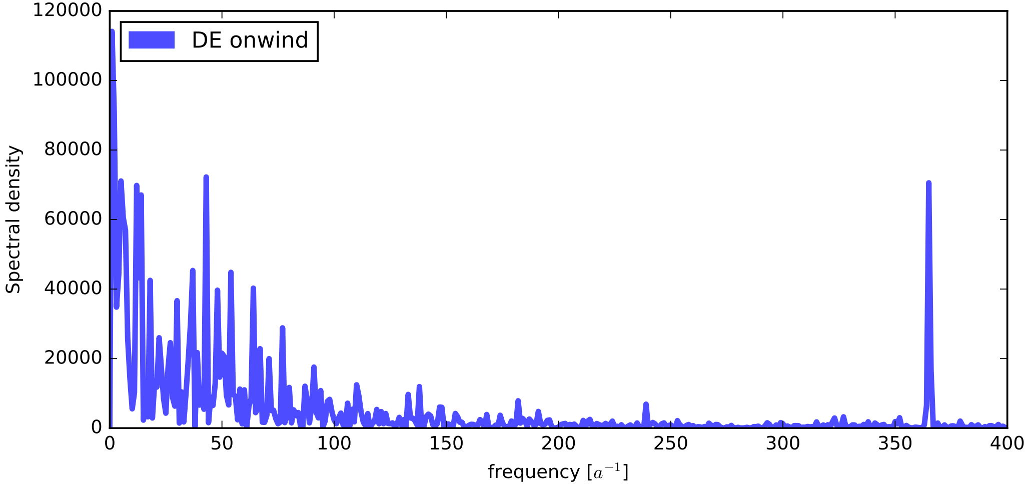
Variability: A continent: Wind plus Hydro

Flexible, renewable hydroelectricity from storage dams in Scandinavia and the Alps can fill many of the valleys; excess energy can either be curtailed (spilled) or stored.



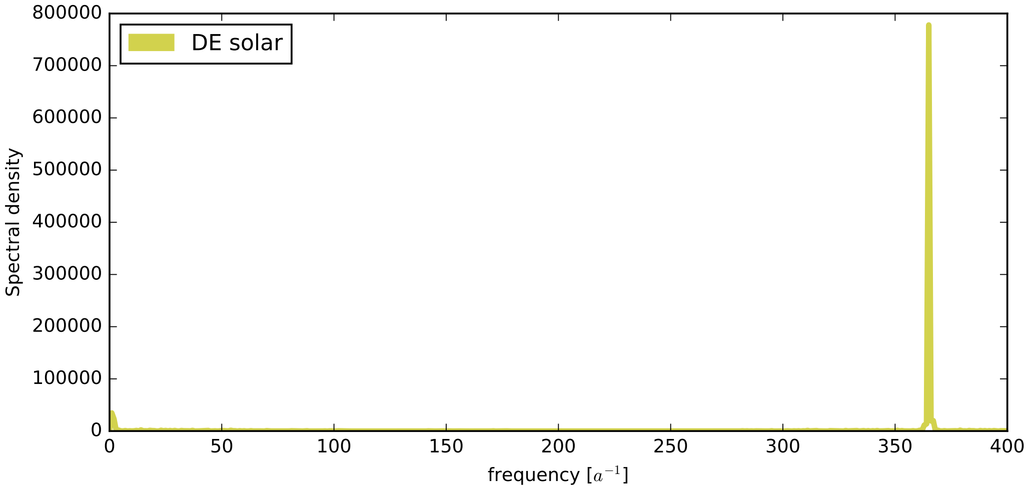
German onshore wind spectrum

If we Fourier transform, seasonal, synoptic and daily patterns become visible.



German solar spectrum

For solar, the daily pattern is dominant, also some seasonal modes.



Need to capture spatial and temporal scope

Wind and solar generation is variable in time and space at different scales:

Variation	Time scale	Space scale	Solution
Diurnal	1 day	Earth circumference	Grid over multiple longitudes, Short-term storage, Demand-Side-Management (DSM)
Synoptic	3-10 days	$\sim$600 km	Continental-scale grids, Long-term storage
Seasonal	1 year	$\pm 23.4^\circ$ latitude	Grid over multiple latitudes, Long-term storage

Short-term storage includes batteries, pumped hydro and thermal energy storage (TES); long-term storage includes chemical storage, hydro reservoirs and long-term TES.

These solutions are not all feasible or cost-effective...

Power Flow in Electricity Networks

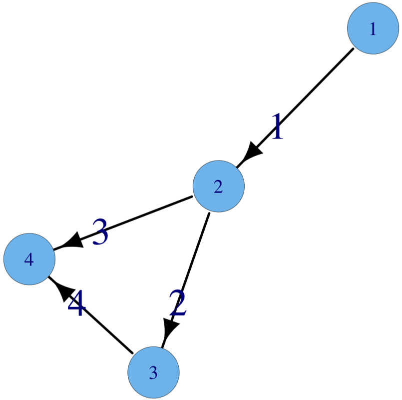
The goal of power flow analysis

The goal of a power/load flow analysis is to find the flows in the lines of a network given a power injection pattern at the nodes.
I.e. given power injection at the nodes

$$\mathbf{P}_i = \begin{pmatrix} 50 \\ 50 \\ 0 \\ -100 \end{pmatrix}$$

what are the flows in lines 1-4?

To find the flows, it is sufficient to know the **impedances** of the lines and the **voltages** at each node.



Alternating voltage and current

The alternating voltage is usually written as a complex quantity in terms of the frequency $\omega = 2\pi f$ and the **Root-Mean-Squared (RMS)** voltage magnitude V_{rms}

$$V(t) = V_{\mathrm{peak}} \sin(\omega t) = \sqrt{2} V_{\mathrm{rms}} e^{j\omega t}$$

Similarly for the current we have

$$I(t) = I_{\mathrm{peak}} e^{j(\omega t - \varphi)} = \sqrt{2} I_{\mathrm{rms}} e^{j(\omega t - \varphi)}$$

Note that they are not necessarily in phase, $\varphi \neq 0$.

The RMS values are useful because then for the **average power** with $\varphi = 0$ we can forget factors of 2

$$\langle P(t) \rangle = \langle \mathrm{Re}[V(t)] \mathrm{Re}[I(t)] \rangle = 2 V_{\mathrm{rms}} I_{\mathrm{rms}} \langle \sin^2(\omega t) \rangle = V_{\mathrm{rms}} I_{\mathrm{rms}}$$

General loads

General loads will have a combination of resistive, capacitive and inductive parts. For an RLC circuit in series the voltage across the components is additive

$$V(t) = RI(t) + L\frac{dI(t)}{dt} + \frac{1}{C}\int_{-infty}^{t} I(\tau)d\tau$$

and therefore for a sinuisoidal voltage with angular frequency ω we get

$$V(t) = \left[R + j\omega L + \frac{1}{j\omega C}\right] I(t)$$

which leads us to define a general complex notion of resistance called **impedance**

$$Z = R + j\omega L + \frac{1}{j\omega C} = R + j(X_L - X_C) = R + jX$$

where X is the **reactance** $X = X_L - X_C$. Thus we have $V(t) = ZI(t)$.

The Problem and its Linearisation

Given nodal power injections P_i, the problem of finding the nodal voltage V_i is essentially a complex quadratic one

$$P_i + jQ_i = V_i I_i^* = \sum_j V_i Y_{ij}^* V_j^*$$

where I_i is the net current leaving the node i from the lines attached there. The current on each line is related linearly to the voltage difference at its end nodes through the admittance matrix Y_ij.

It turns out that in a well-compensated transmission network, this quadratic equation can be linearised. From now on, we will work in this **linear approximation**.

For the linearisation we assume that the voltage magnitude differences across the lines are zero, so that power flows **only** according to the relative voltage angle θ_i differences. Furthermore the voltage angle differences across each line are small enough that $\sin(\theta_i - \theta_j) \sim (\theta_i - \theta_j)$. Finally since for each line $X >> R$, we ignore the resistance and associated thermal losses.

Kirchhoff's Current Law (KCL)

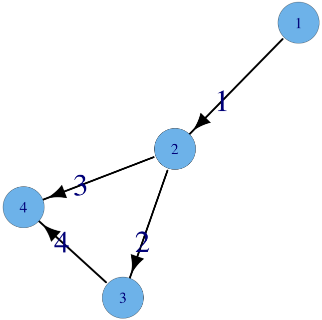
KCL says that the nodal power imbalance p_i at node i is equal to the sum of direct flows f_ℓ arriving at the node from each line ℓ. This can be expressed with the incidence matrix

$$p_i = \sum_\ell K_{i\ell} f_\ell \qquad\qquad \forall i$$

For a directed graph (every edge has an orientation) $G = (V, E)$ with N nodes and L edges, the node-edge **incidence matrix** $K \in \mathbb{R}^{N \times L}$ has components

$$K_{i\ell} = \begin{cases} 1 & \text{if edge } \ell \text{ starts at node } i \\ -1 & \text{if edge } \ell \text{ ends at node } i \\ 0 & \text{otherwise} \end{cases}$$

$$\mathbf{K} = \begin{pmatrix} 1 & 0 & 0 & 0 \\ -1 & 1 & 1 & 0 \\ 0 & -1 & 0 & 1 \\ 0 & 0 & -1 & -1 \end{pmatrix}$$



Kirchhoff's Voltage Law (KVL)

KVL says that the sum of voltage differences across edges for any closed cycle must add up to zero.

It is sufficient to satisfy KVL that the relation between the flow f_ℓ, the voltage angles at the ends of the nodes θ_i and the reactance x_ℓ is given by

$$f_\ell = \frac{\theta_i - \theta_j}{x_\ell} = \frac{1}{x_\ell} \sum_i K_{i\ell} \theta_i$$

[Briefly: the kernel of the incidence matrix $K_{i\ell}$ is combinations of the edges that form **closed cycles**, whose basis we write $C_{\ell c}$. The satisfaction of KVL is thanks to $K_{i\ell} C_{\ell c} = 0$. Cf. **these lectures**.]

Solving the Linear Power Flow Equations

If we combine

$$f_\ell = \frac{1}{x_\ell}\sum_i K_{i\ell}\theta_i$$

with Kirchhoff's Current Law we get

$$p_i = \sum_\ell K_{i\ell} f_\ell = \sum_\ell K_{i\ell}\frac{1}{x_\ell}\sum_j K_{j\ell}\theta_j$$

This is a **weighted Laplacian**. If we write $B_{k\ell}$ for the diagonal matrix with $B_{\ell\ell} = \frac{1}{x_\ell}$ then

$$L = KBK^t$$

and we get a **discrete Poisson equation** for the θ_i sourced by the p_i

$$p_i = \sum_j L_{ij}\theta_j$$

We can solve this for the θ_i and thus find the flows. If we invert L we get

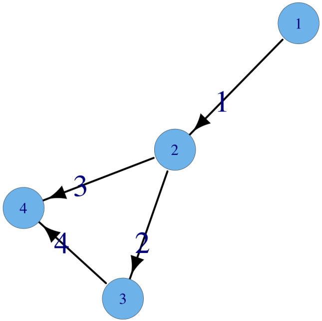
$$f_\ell = \frac{1}{x_\ell}\sum_{i,k} K_{i\ell}(L^{-1})_{ik} p_k = \sum_k \mathrm{PTDF}_{\ell k} p_k$$

4-node example

$$\mathbf{K}_{i\ell} = \begin{pmatrix} 1 & 0 & 0 & 0 \\ -1 & 1 & 1 & 0 \\ 0 & -1 & 0 & 1 \\ 0 & 0 & -1 & -1 \end{pmatrix}$$

$$\mathbf{L}_{ij} = \begin{pmatrix} 1 & -1 & 0 & 0 \\ -1 & 3 & -1 & -1 \\ 0 & -1 & 2 & -1 \\ 0 & -1 & -1 & 2 \end{pmatrix}$$

$$\mathbf{PTDF}_{\ell i} = \begin{pmatrix} 0 & -1 & -1 & -1 \\ 0 & 0 & -2/3 & -1/3 \\ 0 & 0 & -1/3 & -2/3 \\ 0 & 0 & 1/3 & -1/3 \end{pmatrix}$$



Optimising the Electricity Sector One Node per Country

Why optimisation?

In the energy system we have lots of **degrees of freedom**:

1. Power plant and storage dispatch
2. Renewables curtailment
3. Dispatch of network elements (e.g. High Voltage Direct Current (HVDC) lines)
4. Capacities of everything when considering investment

but we also have to respect **physical constraints**:

1. Meet energy demand
2. Do not overload generators or storage
3. Do not overload network

and we want to do this while **minimising costs**. Solution: **optimisation**.

Linear optimisation of annual system costs

Given a desired CO_2 reduction, what is the most cost-effective energy system?

$$\text{Minimise} \begin{pmatrix} \text{Yearly system} \\ \text{costs} \end{pmatrix} = \sum_{n} \begin{pmatrix} \text{Annualised} \\ \text{capital costs} \end{pmatrix} + \sum_{n,t} (\text{Marginal costs})$$

subject to

- meeting energy demand at each node n (e.g. countries) and time t (e.g. hours of year)
- wind, solar, hydro (variable renewables) availability $\forall\, n, t$
- electricity transmission constraints between nodes
- (installed capacity) $\leq$ (geographical potential for renewables)
- CO_2 constraint (95% reduction compared to 1990)
- Flexibility from gas plants, battery storage, hydrogen storage, networks

Optimisation problem

Optimisation problems take the following form:

We have an **objective function** $f : \mathbb{R}^k \to \mathbb{R}$ which is to be either maximised or minimised:

$$\max_x f(x)$$

$[x = (x_1, \ldots x_k)]$ subject to some **constraints** within $\mathbb{R}^k$:

$$\begin{array}{cccc} g_i(x) = c_i & \leftrightarrow & \lambda_i & i = 1, \ldots n \\ h_j(x) \leq d_j & \leftrightarrow & \mu_j & j = 1, \ldots m \end{array}$$

The constraints define a **feasible space** within $\mathbb{R}^k$.

We introduce KKT multipliers λ_i and μ_j for each constraint equation, which have an economic interpretation as the **shadow prices** of the constraints. They tell us how the value of the objective function $f(x^*)$ changes as we relax/tighten the corresponding constraints.

A simple optimisation problem

Consider the following problem. We have a function $f(x, y)$ of two variables $x, y \in \mathbb{R}$

$$f(x, y) = 3x$$

and we want to find the maximum of this function in the $x - y$ plane

$$\max_{x,y \in \mathbb{R}} f(x, y)$$

subject to the following constraints

$$x + y \leq 4 \tag{1}$$

$$x \geq 0 \tag{2}$$

$$y \geq 1 \tag{3}$$

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$$x + y \leq 4 \tag{1}$$

$$x \geq 0 \tag{2}$$

$$y \geq 1 \tag{3}$$

Optimal solution: $x^* = 3, y^* = 1, f(x^*, y^*) = 9.$

Feasibility

The space $X \subset \mathbb{R}^k$ which satisfies

$$
\begin{array}{cccc}
g_i(x) = c_i & \leftrightarrow & \lambda_i & i = 1, \dots n \\
h_j(x) \leq d_j & \leftrightarrow & \mu_j & j = 1, \dots m
\end{array}
$$

is called the **feasible space**.

It will have dimension lower than k if there are independent equality constraints.

It may also be empty (e.g. $x \geq 1, x \leq 0$ in $\mathbb{R}$), in which case the optimisation problem is called **infeasible**.

It can be **convex** or **non-convex**.

If all the constraints are affine, then the feasible space is a convex polygon.

KKT conditions

The **Karush-Kuhn-Tucker (KKT) conditions** are necessary conditions that an optimal solution x^*, μ^*, λ^* always satisfies (up to some regularity conditions):

1. **Stationarity**: For $l = 1, \ldots k$

$$\frac{\partial \mathcal{L}}{\partial x_l} = \frac{\partial f}{\partial x_l} - \sum_i \lambda_i^* \frac{\partial g_i}{\partial x_l} - \sum_j \mu_j^* \frac{\partial h_j}{\partial x_l} = 0$$

2. **Primal feasibility**:

$$g_i(x^*) = c_i$$
$$h_j(x^*) \leq d_j$$

3. **Dual feasibility**: $\mu_j^* \geq 0$
4. **Complementary slackness**: $\mu_j^*(h_j(x^*) - d_j) = 0$

Complementarity slackness for inequality constraints

We have for each inequality constraint

$$\mu_j^* \geq 0$$
$$\mu_j^*(h_j(x^*) - d_j) = 0$$

So **either** the inequality constraint is binding

$$h_j(x^*) = d_j$$

and we have $\mu_j^* \geq 0$.

Or the inequality constraint is NOT binding

$$h_j(x^*) < d_j$$

and we therefore MUST have $\mu_j^* = 0$.

If the inequality constraint is non-binding, we can remove it from the optimisation problem, since it has no effect on the optimal solution.

Return to simple optimisation problem

We want to find the maximum of this function in the $x - y$ plane

$$\max_{x,y\in\mathbb{R}} f(x,y) = 3x$$

subject to the following constraints (now with KKT multipliers)

$$\begin{aligned} x + y \leq 4 \quad &\leftrightarrow \quad \mu_1 \\ -x \leq 0 \quad &\leftrightarrow \quad \mu_2 \\ -y \leq -1 \quad &\leftrightarrow \quad \mu_3 \end{aligned}$$

We know the optimal solution in the **primal variables** $x^* = 3, y^* = 1, f(x^*, y^*) = 9$.

What about the **dual variables** μ_i?

Since the second constraint is not binding, by complementarity $\mu_2^*(-x^* - 0) = 0$ we have $\mu_2^* = 0$. To find μ_1^* and μ_3^* we have to do more work.

Simple problem with KKT conditions

We use stationarity for the optimal point:

$$0 = \frac{\partial \mathcal{L}}{\partial x} = \frac{\partial f}{\partial x} - \sum_i \lambda_i^* \frac{\partial g_i}{\partial x} - \sum_j \mu_j^* \frac{\partial h_j}{\partial x} = 3 - \mu_1 + \mu_2$$
$$0 = \frac{\partial \mathcal{L}}{\partial y} = \frac{\partial f}{\partial y} - \sum_i \lambda_i^* \frac{\partial g_i}{\partial y} - \sum_j \mu_j^* \frac{\partial h_j}{\partial y} = -\mu_1 + \mu_3$$

From which we find:

$$\mu_1^* = 3 - \mu_2^* = 3$$
$$\mu_3^* = \mu_1^* = 3$$

Check interpretation: $\mu_j = \frac{\partial \mathcal{L}}{\partial d_j}$ with $d_j \to d_j + \varepsilon$.

Energy system mapping to an optimisation problem

This optimisation problem has the same basic form as our energy system considerations:

Objective function to minimise	$\leftrightarrow$	**Minimise total costs**
Optimisation variables	$\leftrightarrow$	**Physical degrees of freedom (power plant dispatch, etc.)**
Constraints	$\leftrightarrow$	**Physical constraints (overloading, etc.)**

Linear optimisation problem

Objective is the minimisation of **total annual system costs**, composed of **capital costs** c_* (investment costs) and **operating costs** o_* (fuel ,etc.):

$$\min f(\bar{P}_\ell, \bar{g}_{n,s}, g_{n,s,t}) = \sum_{\ell} c_l \bar{P}_\ell + \sum_{n,s} c_{n,s} \bar{g}_{n,s} + \sum_{n,s,t} w_t o_{n,s} g_{n,s,t}$$

We optimise for n nodes, representative times t and transmission lines l:

- the transmission capacity $\bar{P}_\ell$ of all the lines ℓ
- the generation and storage capacities $\bar{g}_{n,s}$ of all technologies (wind/solar/gas etc.) s at each node n
- the dispatch $g_{n,s,t}$ of each generator and storage unit at each point in time t

Representative time points are weighted w_t such that $\sum_t w_t = 365 * 24$ and the capital costs c_* are annualised, so that the objective function represents the annual system cost.

Model Inputs and Outputs

Inputs	Description
$d_{n,t}$	Demand (inelastic)
$\bar{g}_{n,s,t}$	Per unit availability for wind and solar
$\hat{g}_{n,s}$	Generator installable potentials
various	Existing hydro data
various	Grid topology
η_*	Storage efficiencies
$c_{n,s,t}$	Generator capital costs
$o_{n,s,t}$	Generator marginal costs
c_ℓ	Line costs

$\rightarrow$

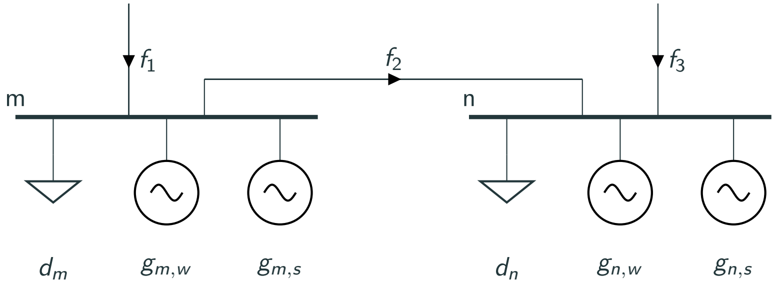
Outputs	Description
$\bar{g}_{n,s}$	Generator capacities
$g_{n,s,t}$	Generator dispatch
$\bar{P}_\ell$	Line capacities
$f_{\ell,t}$	Line flows
λ_*, μ_*	Lagrange/KKT multipliers of all constraints
f	Total system costs

Constraints 1/5: Nodal energy balance

Demand $d_{n,t}$ at each node n and time t is always met by generation/storage units $g_{n,s,t}$ at the node or from transmission flows $f_{\ell,t}$ on lines attached at the node (Kirchhoff's Current Law):

$$p_n = d_{n,t} - \sum_s g_{n,s,t} = \sum_\ell K_{n\ell} f_{\ell,t} \qquad \leftrightarrow \qquad \lambda_{n,t}$$

Nodes are shown as thick busbars connected by transmission lines (thin lines):



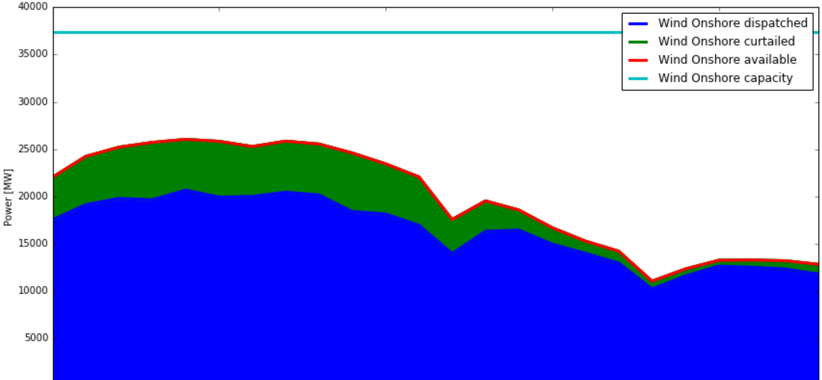
$d_m = g_{m,w} + g_{m,s} + f_1 - f_2$

$d_n = g_{n,w} + g_{n,s} + f_2 + f_3$

Constraints 2/5: Generation availability

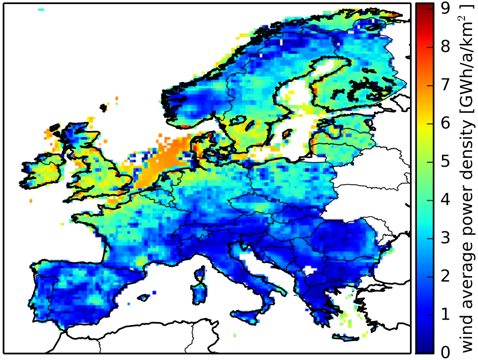
Generator/storage dispatch $g_{n,s,t}$ cannot exceed availability $\bar{g}_{n,s,t} * \bar{g}_{n,s}$, made up of per unit availability $0 \leq \bar{g}_{n,s,t} \leq 1$ multiplied by the capacity $\bar{g}_{n,s}$. The capacity is bounded by the installable potential $\hat{g}_{n,s}$.

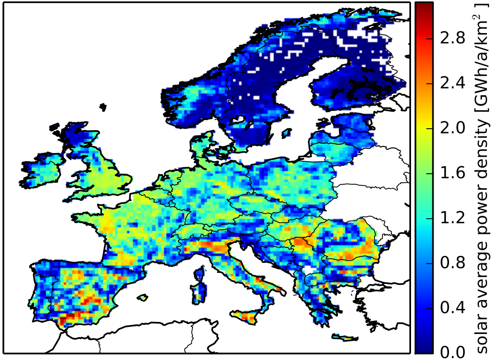
$$0 \leq g_{n,s,t} \leq \bar{g}_{n,s,t} * \bar{g}_{n,s} \leq \bar{g}_{n,s} \leq \hat{g}_{n,s}$$



Expansion potentials for wind and solar

Expansion potentials are limited by **land usage** and **conservation areas**; potential yearly energy yield at each site limited by **weather conditions**:





Constraints 3/5: Storage consistency

Storage units such as batteries or hydrogen storage can work in both storage and dispatch mode. They have a limited energy capacity (state of charge).

$$soc_{n,t} = \eta_0 soc_{n,t-1} + \eta_1 g_{n,t,\text{store}} - \eta_2^{-1} g_{n,t,\text{dispatch}}$$

There are efficiency losses η; hydroelectric dams can also have a river inflow.

Constraints 4/5: Transmission Flows

The linearised **power flows** f_ℓ for each line $\ell \in \{1, \dots L\}$ in an AC network are determined by the **reactances** x_ℓ of the transmission lines and the **net power injection** at each node p_n for $n \in \{1, \dots N\}$.

The flows are related to the angles at the nodes:

$$f_\ell = \frac{\theta_i - \theta_j}{x_\ell} \tag{4}$$

In addition, the angle differences around each cycle must add to zero (Kirchoff's Voltage Law).

Transmission flows cannot exceed the thermal capacities of the transmission lines (otherwise they sag and hit buildings/trees):

$$|f_{\ell,t}| \leq \bar{P}_\ell$$

Since the impedances x_ℓ change as capacity $\bar{P}_\ell$ is added, we do multiple runs and iteratively update the x_ℓ after each run, rather than risking a non-linear (or MILP) optimisation.

Constraints 5/5: Global constraints on CO_2 and transmission volumes

CO_2 limits are respected, given emissions $e_{n,s}$ for each fuel source s:

$$\sum_{n,s,t} g_{n,s,t} e_{n,s} \leq \mathrm{CAP}_{\mathrm{CO}_2} \qquad \leftrightarrow \qquad \mu_{\mathrm{CO}_2}$$

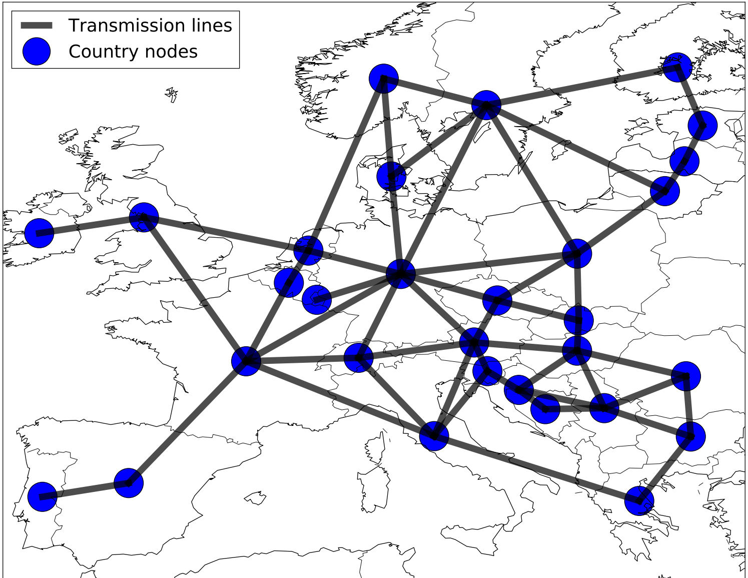
We enforce a reduction of CO_2 emissions by 95% compared to 1990 levels, in line with German and EU targets for 2050.

Transmission volume limits are respected, given length d_l and capacity $\bar{P}_\ell$ of each line:

$$\sum_{\ell} d_\ell \bar{P}_\ell \leq \mathrm{CAP}_{\mathrm{trans}} \qquad \leftrightarrow \qquad \mu_{\mathrm{trans}}$$

We successively change the transmission limit, to assess the costs of balancing power in time (i.e. storage) versus space (i.e. transmission networks).

Example: Europe with One Node per Country



Costs and assumptions for the electricity sector (projections for 2030)

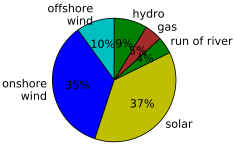
Quantity	Overnight Cost [€]	Unit	FOM [%/a]	Lifetime [a]
Wind onshore	1182	kW_{el}	3	20
Wind offshore	2506	kW_{el}	3	20
Solar PV	600	kW_{el}	4	20
Gas	400	kW_{el}	4	30
Battery storage	1275	kW_{el}	3	20
Hydrogen storage	2070	kW_{el}	1.7	20
Transmission line	400	MWkm	2	40

Interest rate of 7%, storage efficiency losses, only gas has CO_2 emissions, gas marginal costs.

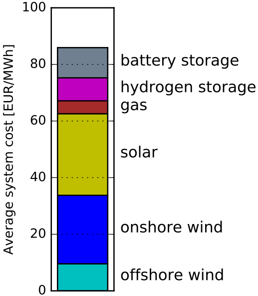
Batteries can store for 6 hours at maximal rating (efficiency 0.9×0.9), hydrogen storage for 168 hours (efficiency 0.75×0.58).

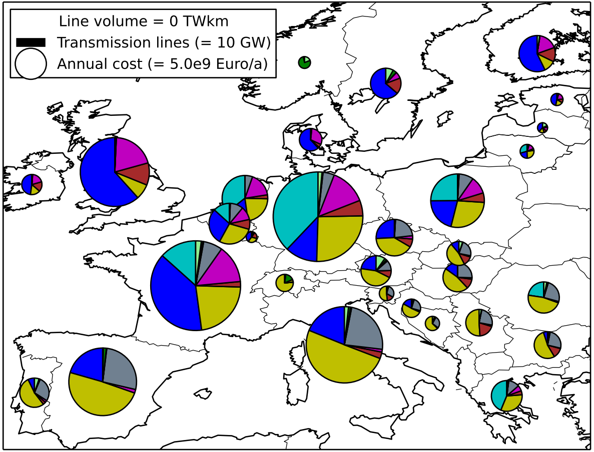
Costs: No interconnecting transmission allowed

Technology by energy:



Average cost **€86/MWh**:

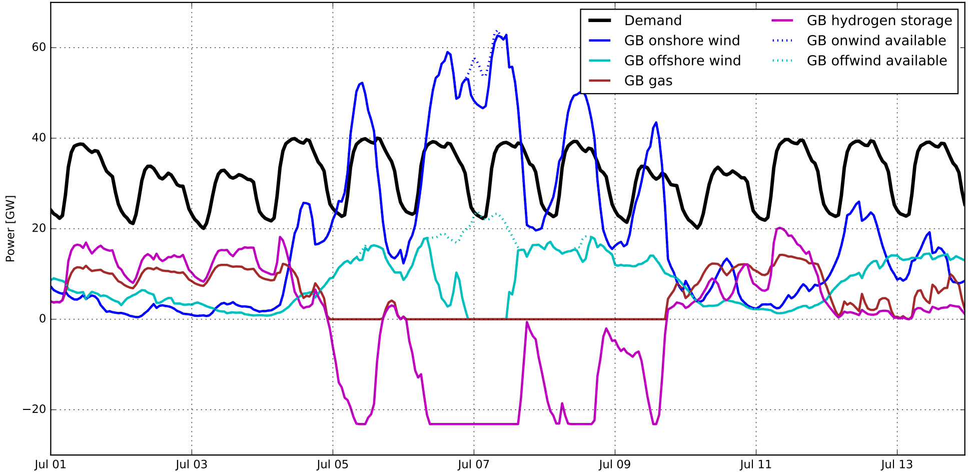




Countries must be self-sufficient at all times; lots of storage and some gas to deal with fluctuations of wind and solar.

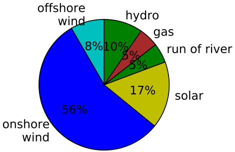
Dispatch with no interconnecting transmission

For Great Britain with no interconnecting transmission, excess wind is either stored as hydrogen or curtailed:

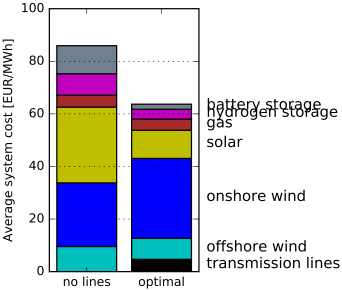


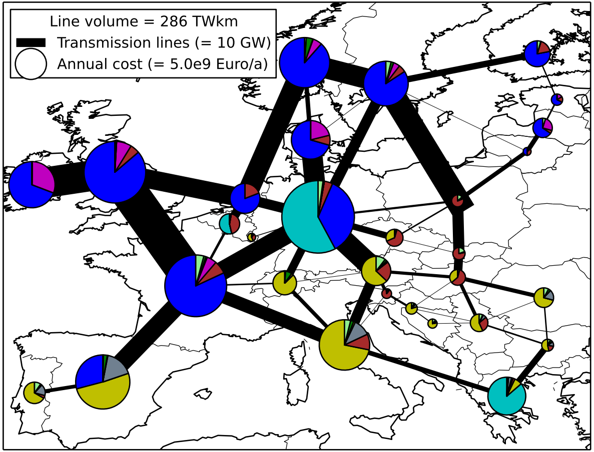
Costs: Cost-optimal expansion of interconnecting transmission

Technology by energy:



Average cost **€64/MWh**:

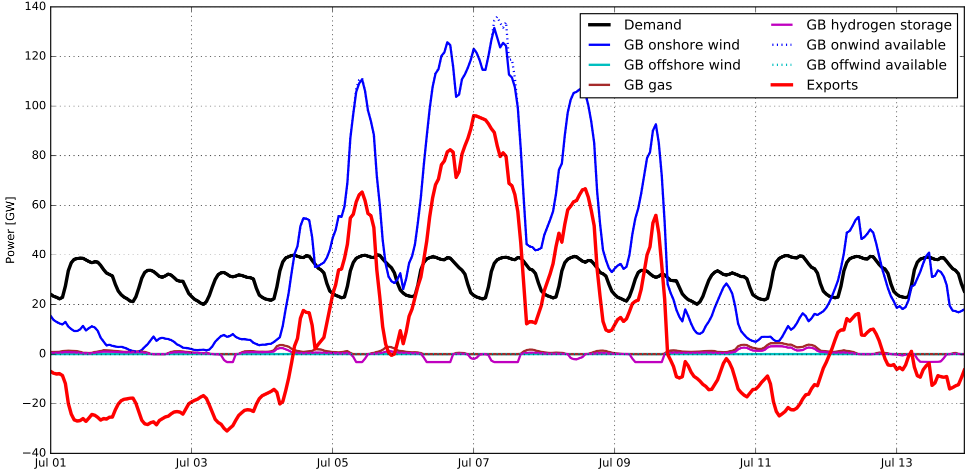




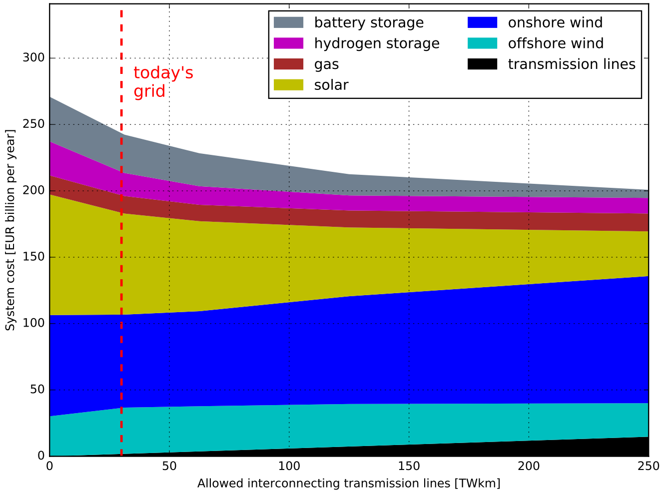
Large transmission expansion; onshore wind dominates. This optimal solution may run into public acceptance problems.

Dispatch with cost-optimal interconnecting transmission

Almost all excess wind can be now be exported:

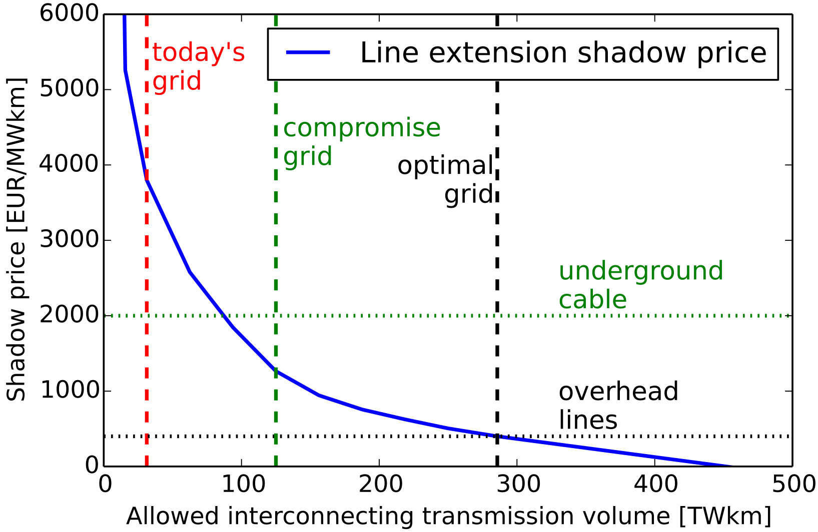


Electricity Only Costs Comparison



- Average total system costs can be as low as € 64/MWh
- Energy is dominated by wind (64% for the cost-optimal system), followed by hydro (15%) and solar (17%)
- Restricting transmission results in more storage to deal with variability, driving up the costs by up to 34%
- Many benefits already locked in at a few multiples of today's grid

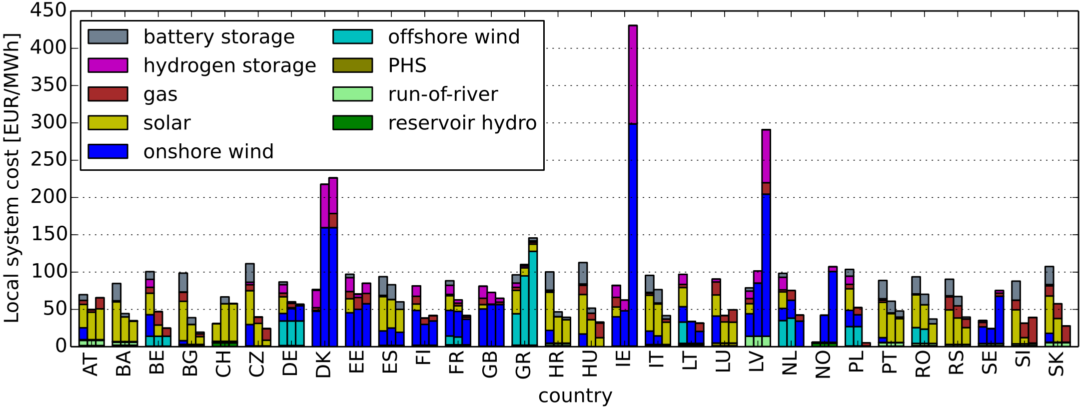
Grid expansion CAP shadow price as CAP relaxed



- With overhead lines the optimal system has around 7 times today's international transmission volume
- With underground cables (5-8 times more expensive) the optimal system has around 3 times today's international transmission

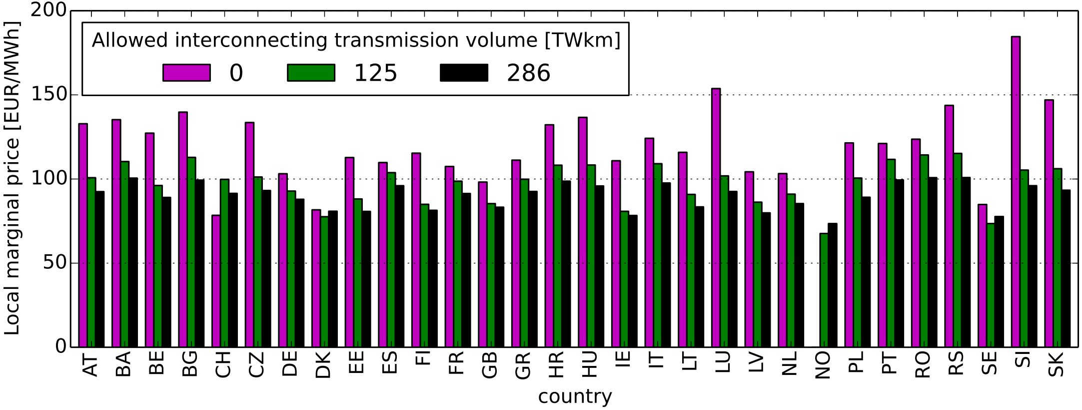
Distribution of costs

As transmission volumes increase, costs become more unequally distributed...

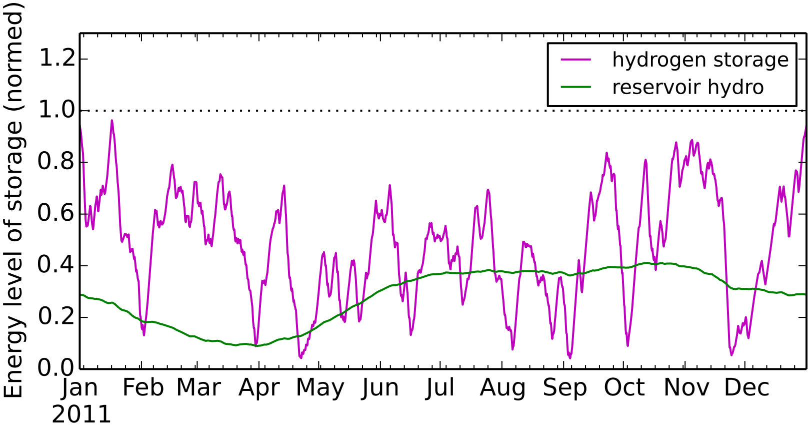


Distribution of prices

...while market prices converge.

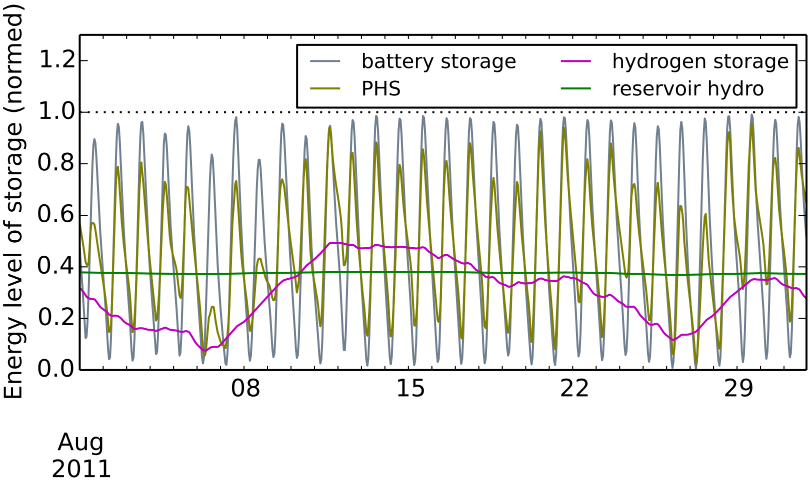


Different flexibility options have difference temporal scales



- Hydro reservoirs are **seasonal**
- Hydrogen storage is **synoptic**

Different flexibility options have difference temporal scales



- Pumped hydro and battery storage are **daily**

References

These results are described in:

- D. Schlachtberger, T. Brown, S. Schramm, M. Greiner, "The benefits of cooperation in a highly renewable European electricity network," *Energy*, 134, 469-481, 2017, preprint arXiv:1704.05492.

All input data, model code and output data are available under a Creative Commons Attribution 4.0 licence at:

- `https://zenodo.org/record/804337`

Increasing Spatial Resolution

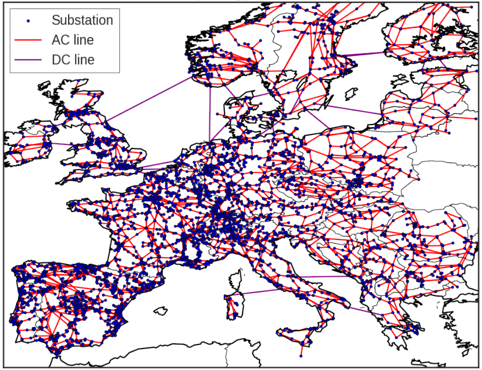
Spatial resolution

We need spatial resolution to:

- capture the **geographical variation** of renewables resources and the load
- capture **spatio-temporal effects** (e.g. size of wind correlations across the continent)
- represent important **transmission constraints**

BUT we do not want to have to model all 5,000 network nodes of the European system.

Network topology of the HV grid



Source: Own representation of Bart Wiegman's GridKit extract of the online ENTSO-E map, https://doi.org/10.5281/zenodo.55853

Clustering: Many algorithms in the literature

There are lots of algorithms for clustering/aggregating networks, particularly in the engineering literature:

- *k*-means clustering on (electrical) distance
- *k*-means on load distribution
- Community clustering (e.g. Louvain)
- Spectral analysis of Laplacian matrix
- Clustering of Locational Marginal Prices with nodal pricing (sees congestion and RE generation)
- PTDF clustering
- Cluster nodes with correlated RE time series

The algorithms all serve different purposes (e.g. reducing part of the network on the boundary, to focus on another part).

k-means clustering on load & conventional generation

Our **goal**: maintain main transmission corridors of today to investigate highly renewable scenarios with no grid expansion. Since generation fleet is totally rebuilt, do not want to rely on current generation dispatch (like e.g. LMP algorithm).

Today's grid was laid out to connect big generators and load centres.

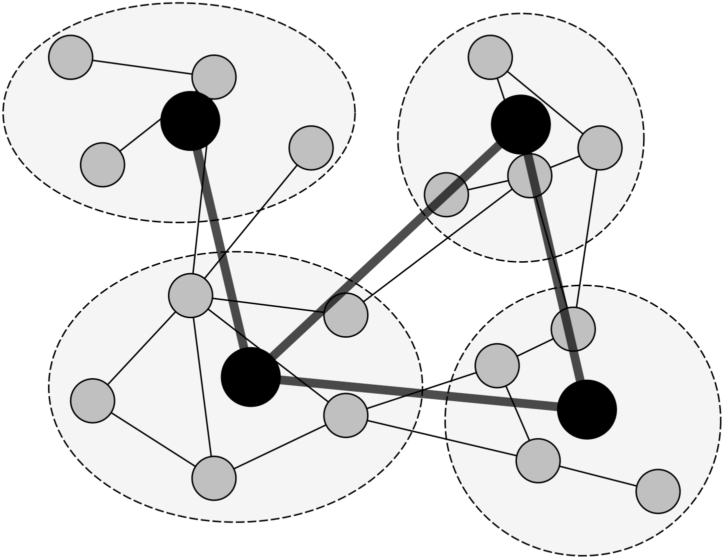
Solution: Cluster nodes based on load and conventional generation capacity using k-means.

I.e. find k centroids and the corresponding k-partition of the original nodes that minimises the sum of squared distances from each centroid to its nodal members:

$$\min_{\{x_c\}} \sum_{c=1}^{k} \sum_{n \in N_c} w_n ||x_c - x_n||^2 \tag{5}$$

where each node is weighted w_n by the average load and the average conventional generation there.

k-means clustering

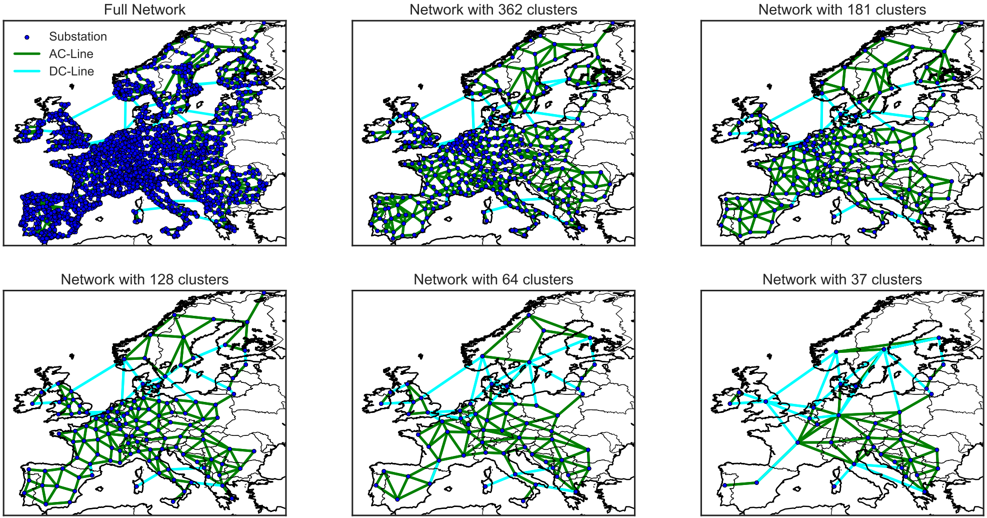


Reconstitution of network

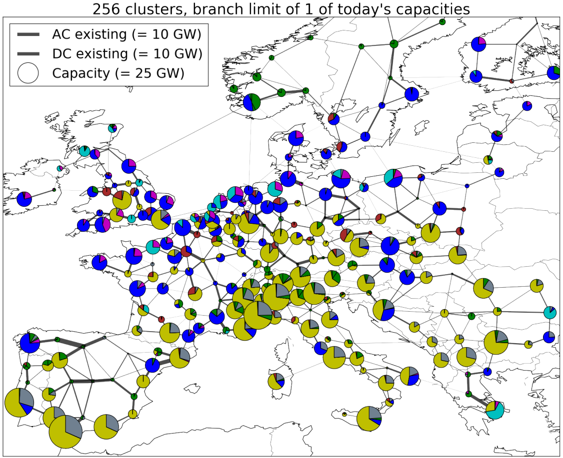
Once the partition of nodes is determined:

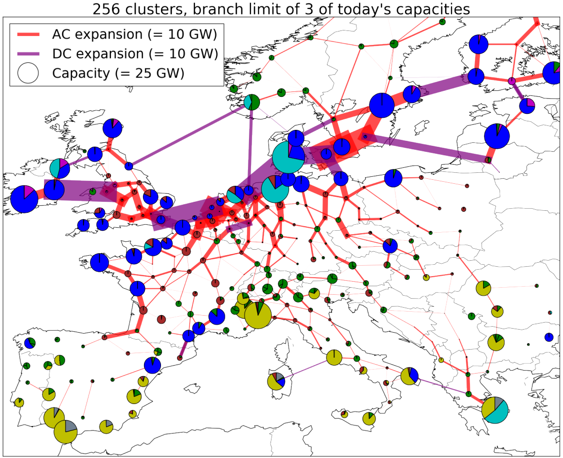
- A new node is created to represent each set of clustered nodes
- Hydro capacities and load is aggregated at the node; VRE (wind and solar) time series are aggregated, weighted by capacity factor; potentials for VRE aggregated
- Lines between clusters replaced by single line with length 1.25 $\times$ crow-flies-distance, capacity and impedance according to replaced lines
- $n-1$ blanket safety margin factor grows from 0.3 with ≥ 200 nodes to 0.5 with 37 nodes (to account for aggregation)

k-means clustering: Networks



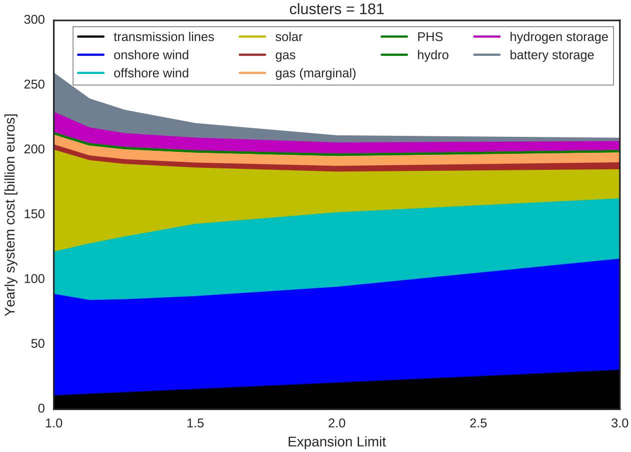
Spatial resolution: Electricity sector with and without grid expansion





offshore wind · onshore wind · solar · gas · hydro · hydrogen storage · battery storage

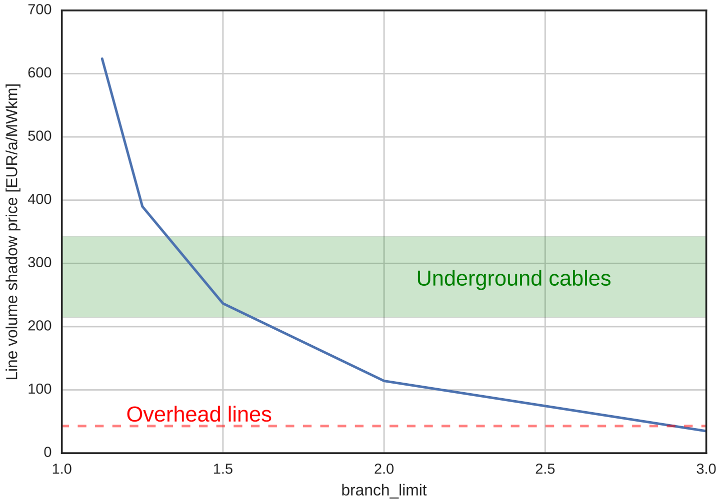
Behaviour as transmission expansion is allowed



- Big **non-linear cost reduction** as grid is expanded, from 82€/MWh to 66€/MWh (drop of 50 bill. €/a)
- Most of cost reduction happens with **25% grid expansion** compared to today's grid; costs rather flat once capacity has doubled
- Need for solar and batteries decrease significantly as grid expanded; with cost-optimal grid, system is dominated by wind

Source: Schlachtberger et al, 2017, Hörsch et al, 2017

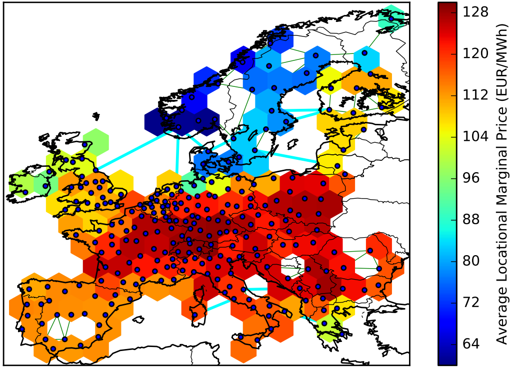
Grid expansion CAP shadow price for 181 nodes as CAP relaxed



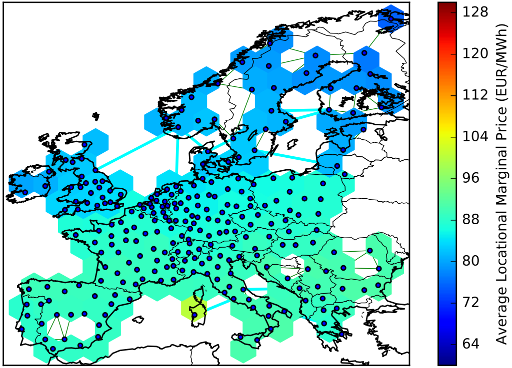
- With overhead lines the optimal system has around 3 times today's transmission volume
- With underground cables (5-8 times more expensive) the optimal system has around 1.3 to 1.6 times today's transmission volume

Locational Marginal Prices CAP=1 versus CAP=3

With today's capacities:



With three times today's grid:



Coupling Electricity to Heating and Transport

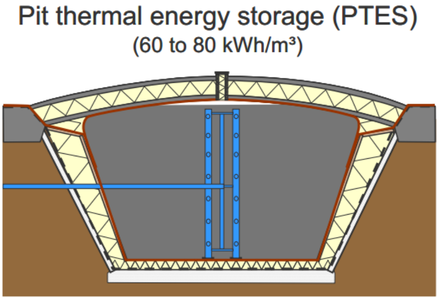
Sector Coupling

Idea: Couple the electricity sector to heating and mobility.

This enables decarbonisation of these sectors **and** offers more flexibility to the power system.

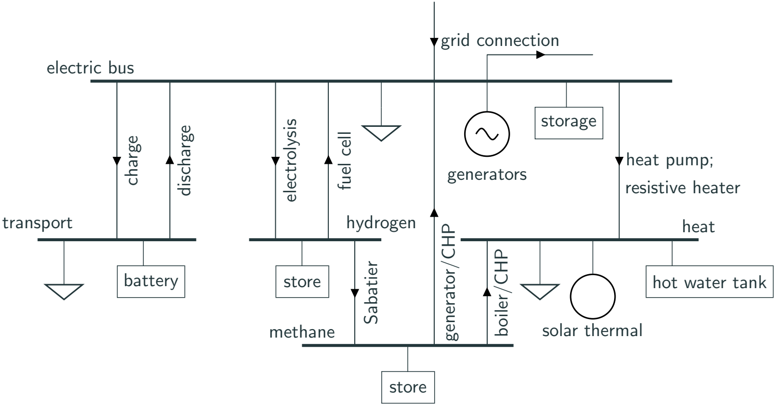
Battery electric vehicles can change their charging pattern to benefit the system and even feed back into the grid if necessary

Heat is much easier and cheaper to store than electricity, even over many months

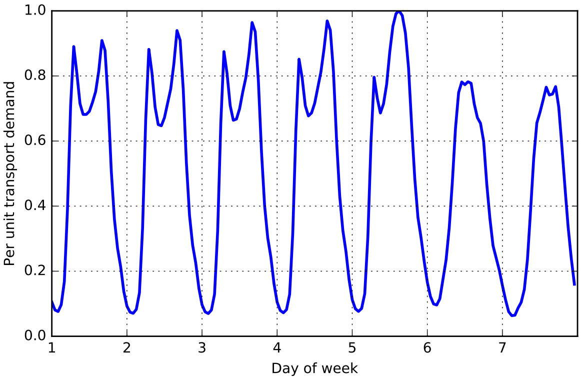


Sector coupling: A new source of flexibility

Couple the electricity sector (electric demand, generators, electricity storage, grid) to electrified transport and low-T heating demand (model covers 75% of final energy consumption in 2014). Also allow production of synthetic hydrogen and methane.



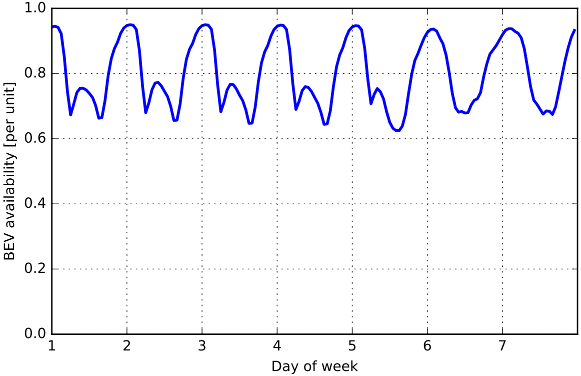
Transport sector: Electrification of Transport



Weekly profile for the transport demand based on statistics gathered by the German Federal Highway Research Institute (BASt).

- All road and rail transport in each country is electrified, where it is not already electrified
- Because of higher efficiency of electric motors, final energy consumption 3.5 times lower at 1014 TWh_{el}/a for the 30 countries than today
- In model can replace Electric Vehicles (EVs) with Fuel Cell Vehicles (FCVs) consuming hydrogen. Advantage: hydrogen cheap to store. Disadvantage: efficiency of fuel cell only 60%, compared to 90% for battery discharging.

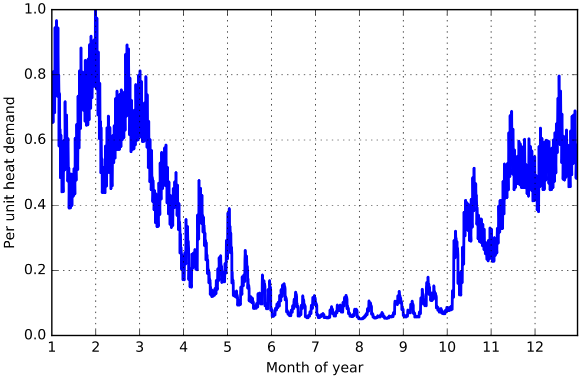
Transport sector: Battery Electric Vehicles



Availability (i.e. fraction of vehicles plugged in) of Battery Electric Vehicles (BEV).
BEV production costs 10-20% more expensive than Diesel in 2030, but lower fuel costs.

- Assumed that all passenger cars are Battery Electric Vehicles (BEVs), each with 50 kWh battery available (rest as buffer) and 11 kW charging power
- Assumed that all BEVs have time-dependent availability, averaging 80%, maximum 95% (at night)
- No changes in consumer behaviour assumed (e.g. car-sharing), but even with 50% reduction in BEVs, the results are barely effected (0.1%)
- BEVs are treated as exogenous (capital costs NOT included in calculation)

Heating sector: Many Options with Thermal Energy Storage (TES)



Heat demand profile from 2011 in all 30 countries using population-weighted average daily T in each country, degree-day approx. and scaled to Eurostat total heating demand.

- All space and water heating in the residential and services sectors is considered, with no additional efficiency measures (conservative) - total heating demand is 3231 $\mathrm{TWh}_{th}/\mathrm{a}$.
- Heating demand can be met by resistive heaters, gas boilers, solar thermal, Combined-Heat-and-Power (CHP) units and heat pumps, which have an average Coefficient of Performance of just under 3. No industrial waste heat.
- Thermal Energy Storage (TES) is available to the system as hot water tanks.

Centralised District Heating versus Decentralised Heating

We model both fully decentralised heating and cases where up to 60% of heat demand is met with district heating in northern countries.

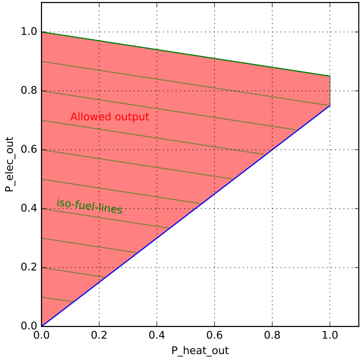
Decentral heating can be supplied by:

- Gas boilers
- Resistive heaters
- Small CHPs
- Small solar thermal
- Water tanks with short time constant $\tau = 3$ days
- Heat pumps

Central heating can be supplied via district heating networks by:

- Gas boilers
- Resistive heaters
- Large CHPs
- Large solar thermal
- Water tanks with long time constant $\tau = 180$ days

CHP feasible dispatch:



Cost and other assumptions

Quantity	Overnight Cost [€]	Unit	FOM [%/a]	Lifetime [a]
Sabatier	1100	kW_{gas}	2	20
Heat pump	1050	kW_{th}	1.5	20
Resistive heater	100	kW_{th}	2	20
Gas boiler	300	kW_{th}	1	20
Decentral solar thermal	270	kW_{th}	1.3	20
Central solar thermal	140	kW_{th}	1.4	20
Decentral CHP	1400	kW_{el}	3	25
Central CHP	650	kW_{el}	3	25
Central water tanks	20	m^3	1	40
District heating	400	kW_{th}	1	50

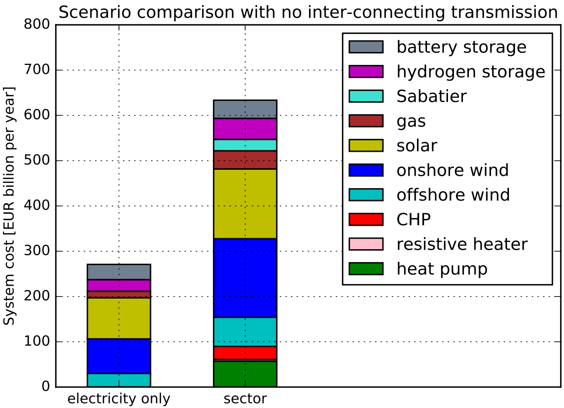
Costs oriented towards Henning & Palzer (2014, Fraunhofer ISE)

Scenarios: Add flexibility one feature at a time

We now consider 10 scenarios where flexibility is added in stages:

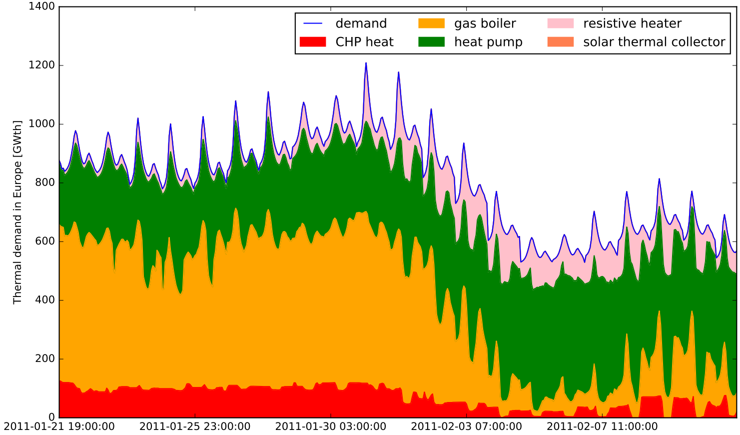
1. **electricity only**: no sector coupling
2. **sector**: sector coupling to heating and transport with no use of sector flexibility
3. **sector BEV**: sector coupling; Battery Electric Vehicles (BEV) can shift their charging time
4. **sector BEV V2G**: sector coupling; BEV can in addition feed back into the grid (V2G)
5. **sector FC50**: sector coupling; 50% of BEV replaced by FCV
6. **sector FC100**: sector coupling; 100% of BEV replaced by FCV
7. **sector TES**: sector coupling with short-term Thermal Energy Storage (TES) $\tau = 3$ days
8. **sector central**: sector coupling with 60% district heating in North and long-term TES
9. **sector all flex**: sector coupling with all flexibility options
10. **sector all flex central**: sector coupling with all flexibility options and 60% district heating

From electricity to sector coupling



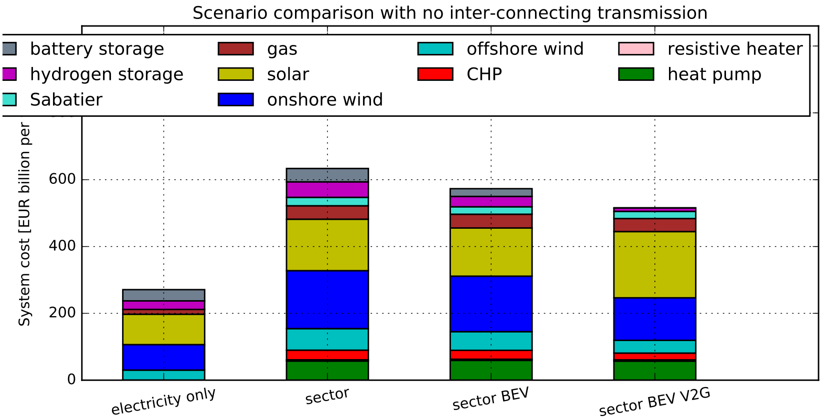
- With sector coupling costs are over twice as much because of higher energy demand, heating units and strong seasonality of heating demand.
- Decentralised heating demand peak (1260 GW_{th}) met by heat pumps (500 GW_{th}), gas boilers (750 GW_{th}), resistive heaters (360 GW_{th}) and CHP (165 GW_{th}).
- No additional flexibility activated.
- 800 TWh_{th}/a of natural gas used (limited by CO2 cap); 725 TWh_{th}/a of hydrogen produced; 530 TWh_{th}/a of syngas produced, i.e. 40% of methane used is synthetic

Heat coverage for decentralised heating



- Over the year heat pumps (green) provide most of the heat energy, as in the second week shown here
- However when demand is high, heat pump COP is low and there is no wind or sun, gas boilers must step in (orange), as in first week shown here, to cover most of the heat demand

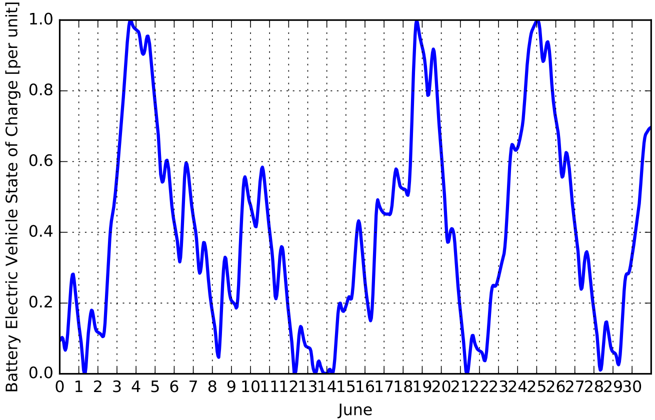
Using Electric Vehicle flexibility



With V2G total solar capacity jumps from 1,764 GW to 2,426 GW.

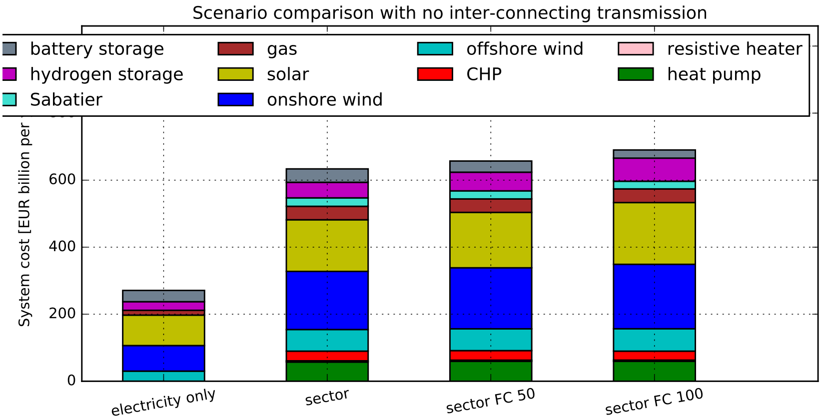
- Shifting the charging time to benefit the system reduces system costs by 10%.
- This Demand-Side Management reduced the need for stationary storage by half.
- Allowing BEVs to feed back into the grid (V2G) reduces costs by a further 10%.
- This eliminates the need for batteries and allows much more solar to be integrated.

Battery Electric Vehicle state of charge



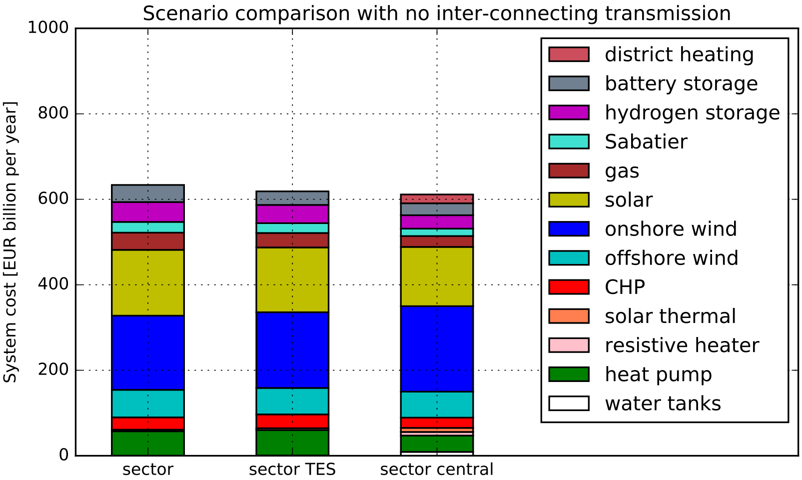
- Aggregated Battery Electric Vehicle state of charge in Germany shows very little day-to-day cycling which would degrade the battery, even with V2G and lots of solar
- Bigger longer-term synoptic variations driven by wind
- NB: This shows only the SOC available to the V2G (50 kWh per vehicle); there is also a buffer that is not available to V2G
- Only 0.1% change in total costs if V2G capacity reduced by 50%

Using Fuel Cells instead of Electric Vehicles



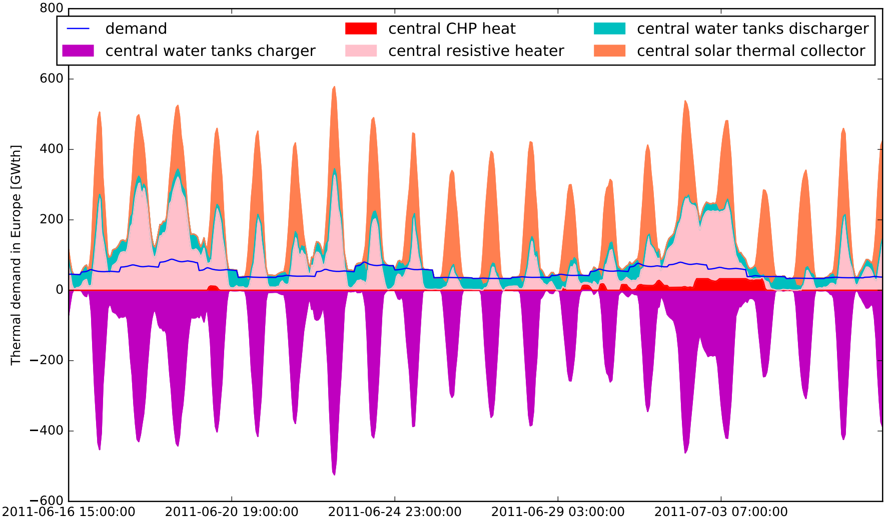
- The lower efficiency of fuel cells (60%) means more energy has to be generated, leading to higher overall costs.
- These higher costs are NOT compensated by the extra flexibility of cheap hydrogen storage.
- FCEVs are also more expensive than BEVs, then comes the hydrogen infrastructure costs...

Using heating sector flexibility



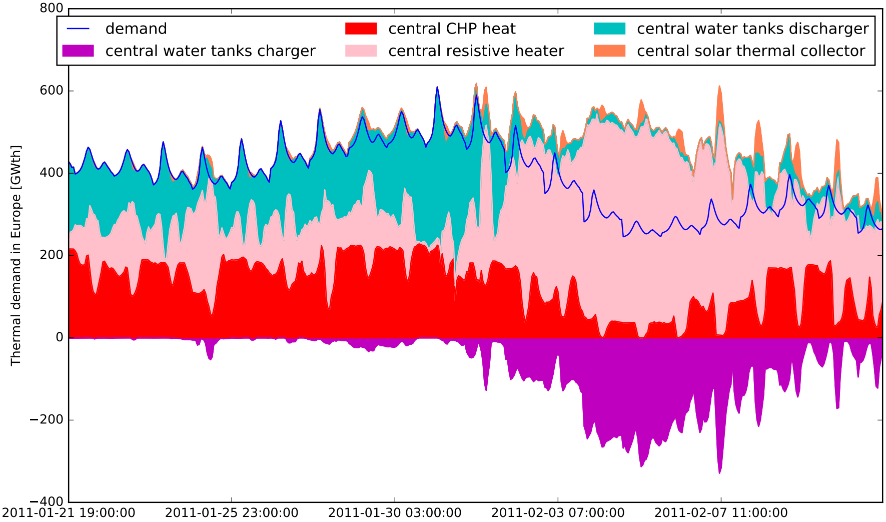
- Allowing short-term Thermal Energy Storage (TES) ($\tau =$ 3 days) has only a 2% effect on the costs.
- Using 60% centralised heating enables the use of long-term TES ($\tau = 180$ days). In this case solar thermal is built to fill the TES in the summer. The cost decrease is mostly compensated by the cost of the district heating. HOWEVER, reduced natural gas distribution costs NOT

Centralised heating: charging TES with solar thermal in summer



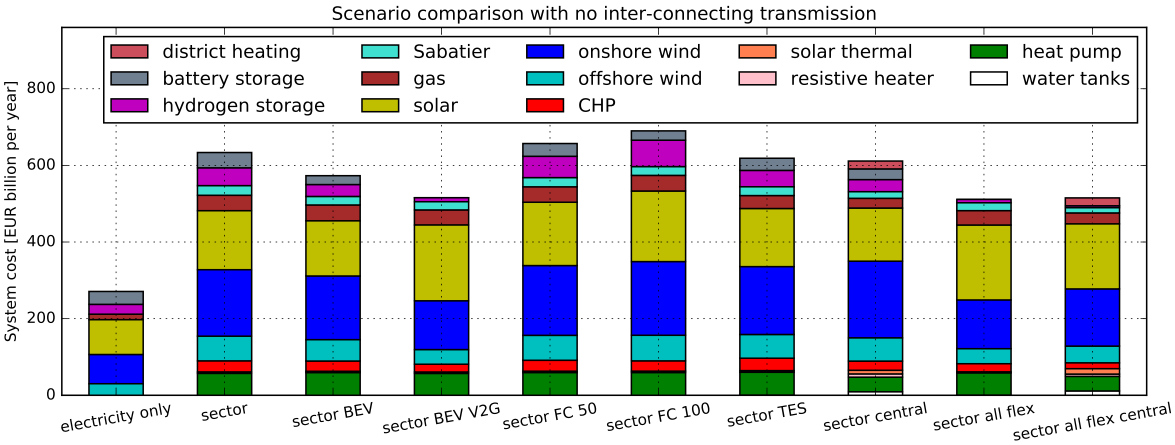
In summer solar thermal collectors (orange) and resistive heaters (pink) fill up the long-term centralised thermal energy storage (purple).

Centralised heating: discharging TES in winter

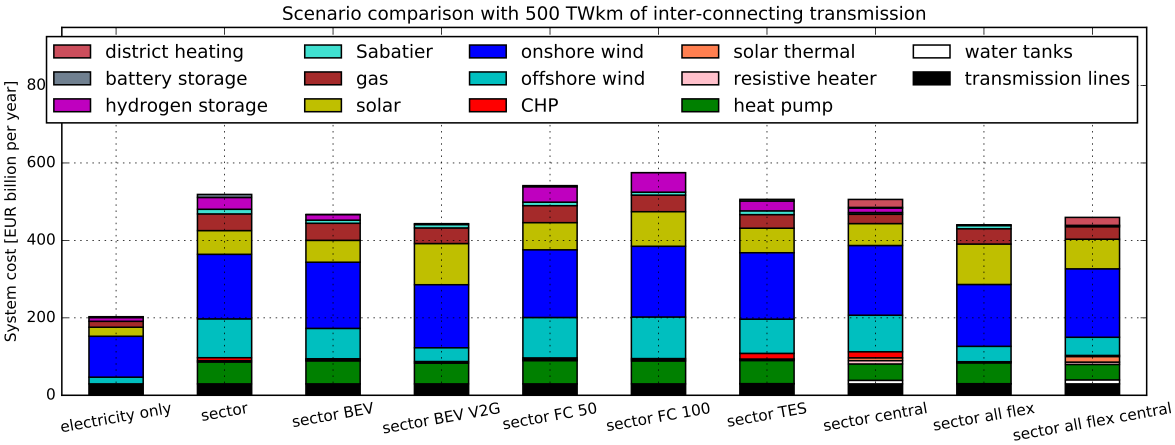


In winter, demand is met by a combination of CHP (red), resistive heating (pink) and the discharge from the long-term centralised TES (cyan).

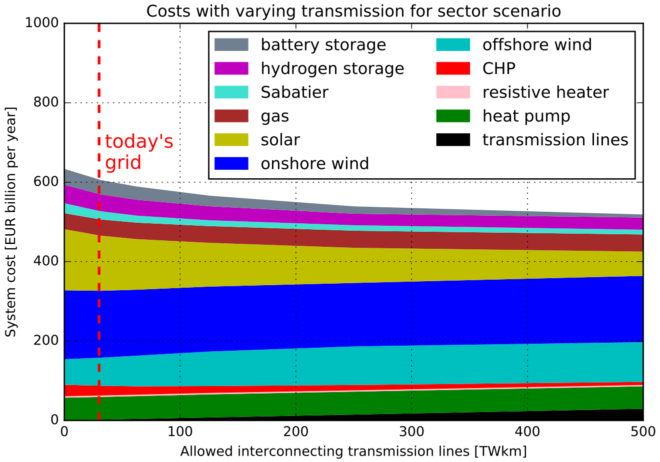
Scenario comparison with no inter-connecting transmission



Scenario comparison with optimal inter-connecting transmission

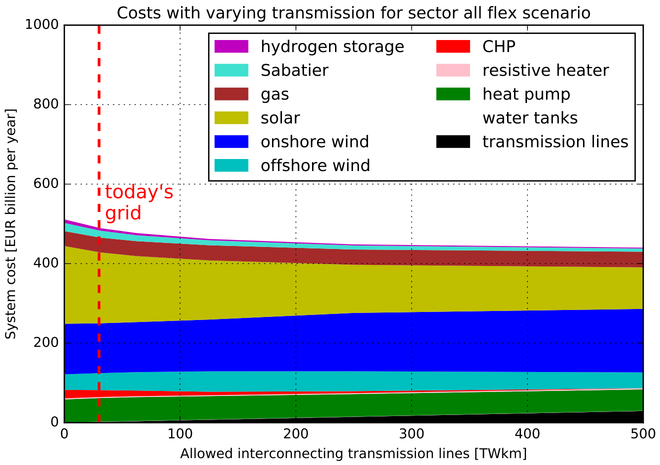


Sector Coupling with No Extra Flexibility



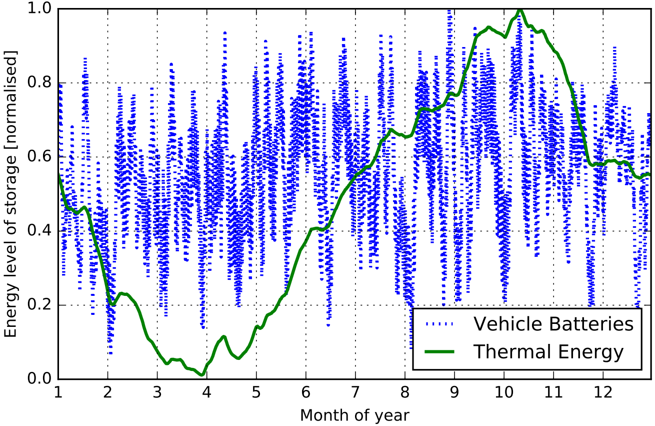
- Solution with no inter-connecting transmission costs 33% more than optimal transmission (comparable to electricity-only scenario)
- Gas boilers replace CHPs as transmission inceases, since transmission reduces need for gas for balancing in electricity sector
- Need stationary batteries and hydrogen storage to balance RES variability
- Transmission allows cheaper wind to substitute for solar power

Sector Coupling with All Extra Flexibility (V2G and TES)



- The benefits of inter-connecting transmission are now much weaker: it reduces costs by only 16%
- Even with no transmission, the system is cheaper than all levels of transmission for sector-coupling with no sector flexibility
- System costs are comparable to today's (with same cost assumptions, today's system comes out around € 377 billion per year, excluding costs of greenhouse gases and airborne pollution, estimated by UBA to be €130 billion in 2014 in Germany alone)

Storage energy levels: different time scales



The different scales on which storage flexibility work can be seen clearly when examining the state of charge.

- Long-Term Thermal Energy Storage (TES) has a dominant seasonal pattern, charging in summer and discharging in winter. Additional synoptic-scale fluctuations are super-imposed.
- Battery Electric Vehicles (BEV) with Vehicle-To-Grid (V2G) show large fluctuations on daily and synoptic scales.

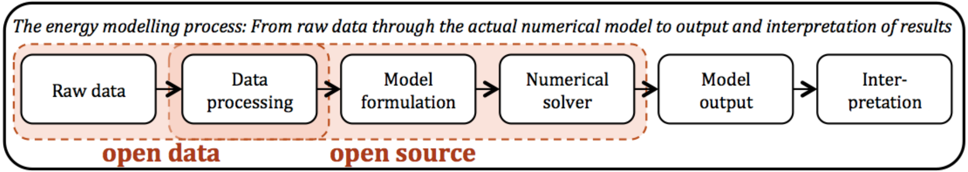
Unfinished results

- Autonomous **car sharing** $\Rightarrow$ times with zero BEV availability.
- **Thermo-chemical storage** allows long-term storage, decentrally (e.g. $CaCl_2$, CaO, silica gel).
- Sensitivity to **heating sector efficiency**.
- Demand from **industry, aviation, shipping**.
- Higher **spatial resolution** to capture **full transmission grid** and **resource spatial variation**.

Open Energy Modelling

Idea of Open Energy Modelling

The whole chain from raw data to modelling results should be open:



Open data + free software $\Rightarrow$ Transparency + Reproducibility

There's an initiative for that! Sign up for the mailing list / come to the next workshop:
TU München, 11-13 October 2017.

openmod open energy modelling initiative

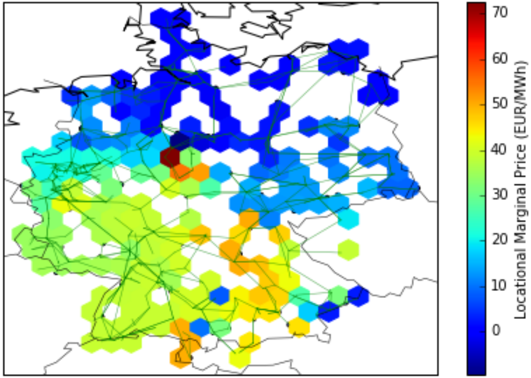
openmod-initiative.org

Source: openmod initiative

Python for Power System Analysis (PyPSA)

The FIAS software PyPSA is online at `http://pypsa.org/` and on github. It can do:

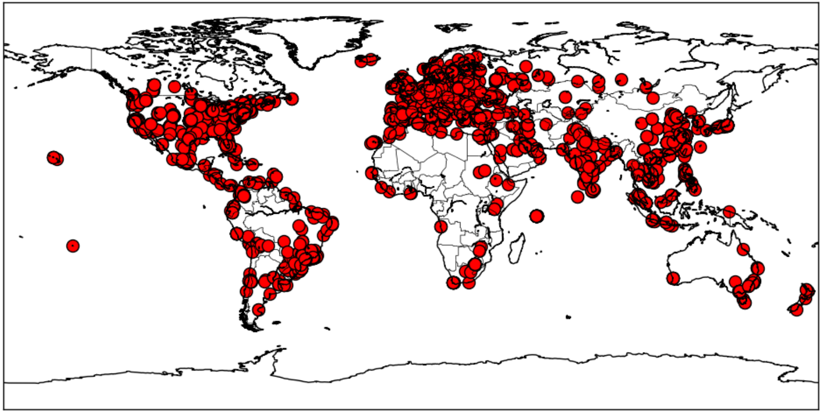
- Static **power flow**
- **Linear optimal power flow** (LOPF) (multiple periods, unit commitment, storage, coupling to other sectors)
- **Security-constrained LOPF**
- Total electricity system **investment optimisation**



It has models for storage, meshed AC grids, meshed DC grids, hydro plants, variable renewables and sector coupling.

PyPSA users

PyPSA is being actively used by around a dozen institutions (that we know of...) and the website has been visited by people from 120+ countries:



Conclusions

Conclusions

- Designing the energy system involves large amounts of **data** and complex **optimisation**
- This is **no single solution** for highly renewable systems, but a **family of solutions** with different costs and compromises
- Generation costs always dominate total costs, but the **grid can cause higher generation costs** if expansion is restricted
- Cost-optimal grid expansion favours wind over solar
- Much of the need for stationary storage can be eliminated by **sector-coupling**, which also makes grid expansion less important
- Understanding the need for **flexibility at different temporal and spatial scales** is key to mastering the complex interactions in the energy system
- **Open energy modelling** increases **transparency**, **reproducibility** and **credibility**, which lead to better research and policy advice (no more ‘black boxes’)

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