Evaluating regulatory measures in the German energy transition – A European multimodal market optimization approach including distributed flexibilities

by

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Abstract

Global efforts concerning the efficient transformation of the energy production landscape towards a renewable system force political decision-makers to set the right regulatory boundaries. This paper presents a methodical approach to simulating the hourly operation of large scale energy systems with a high penetration of renewable energy sources. Furthermore, the approach allows an active participation of spatially highly resolved decentralized generation in the energy market. Modelling the operation of each central power generation unit and decentralized generation as locally aggregated actors ensures a realistic representation of individual dispatch decisions. The inclusion of regulatory defined price markups is a central aspect of the model framework. This allows for the analysis of the sensitivity of these price components on the dispatch of power plants. We show that a decentralized matching of generation and consumption can be supported significantly by an exemption from grid fees, taxes and concession fees. It is mandatory to develop an algorithmic approach which allows such detailed analyses being possible on currently available computing clusters within a reasonable solving time. Therefore, this approach can be applied for sensitivity analysis to redefine regulatory frameworks with regard to exemptions for special technologies or dispatch strategies which support sector coupling and subsequently the energy transition.

1. Introduction

The United Nations committed themselves to ambitiously reduce greenhouse gas emissions ensuring a deceleration of global warming [1]. These efforts have to be manifested in national (or European) law supporting energy efficiency, renewable energies and sector coupling[1] [2]. Those regulatory measures are often applied using incentives, subsidies and resulting economical costs which can be rolled over in levies. The political challenge is to provide cost efficient interventions in order to reach the climate targets and corresponding constraints. This leads to a need for fundamental optimization models which allow an economic assessment of individual dispatch decisions and their systemic feedback. Fundamental models enable the evaluation of the power system's sensitivity to interventions. Mathematical optimization delivers the framework for formulating rational decisions of entities within the power sector. Common fundamental models simplify distributed energy resources (DER), mainly wind and photovoltaics (PV), through heavy aggregation and usually define their dispatch decision exogenously in a pre-processing procedure due to complexity reasons [3]–[7]. The systemic

[1] Definition : Use of final energy in a sector (electricity, gas, heat, transport, …) the energy was primarily not provided in (e.g. transformation of electricity supplied by wind energy into gas using electrolysis/methanation).

feedback is therefore not considered adequately in decentralized generation. This distortion is inadmissible especially in energy systems with high levels of DER that actively participate in the market. Detailed unit commitment models which can cope with conventional power stations but also a large amount of active dispatched DER enables more precise techno-economic evaluations. This paper delivers an approach to optimizing the interconnected European power system including all large scale (>10 MW) hydro-thermal power plants in the European energy system (covering all interconnected zones of European Network of Transmission System Operators for Electricity; abbr.: ENTSO-E). Furthermore a data set of 22 million individual buildings is used to model decentralized flexibilities and renewables bottom-up within Germany. The objective is to integrate user- and technology-specific regulatory incentives into a bottom-up power system optimization with a high spatial resolution. This provides realistic conclusions by taking region-specific conditions into account. This paper's focus is on developing a methodical approach which is able to include highly spatial resolved DER into a pan-European unit commitment model. The applied regulatory framework focuses on German law. Nevertheless the approach can easily be applied to other legal environments.

2. Analysis of regulatory barriers in Germany

The current legal framework in Germany provides a considerable burden through taxes, levies and fees for the purchase of electricity and gas, in addition to the primary energy procurement costs. These can have an inhibiting effect on the dispatch or on investment signals for technologies whose market participation appears to make sense in the context of the energy transition [8], [9]. Against the background of the energy transition as a desired goal for society, the influence of these measures with regard to their economic efficiency must therefore be examined. These components, and even more all their sensitivity, are usually neglected in economic equilibrium models simulating electricity markets. Therefore, the present paper integrates the main regulatory and market conditions applied in the electricity and gas sectors into the later presented multimodal market model in order to quantitatively identify possible barriers. The aim is to select regulatory interventions in the energy market in such a way that obstacles are removed that counteract the goals of energy system transformation.

The composition of the retail price for electricity and gas (2016) is illustrated in Figure 1 and Figure 2. The dominance of regulated price elements is particularly evident in the electricity sector. Only energy procurement, distribution, other costs and corresponding margins are fully organised on a competitive basis. The competitively organised price component are made up of the direct costs of energy procurement on wholesale markets (exchange, OTC, long-term supply contracts). In addition, the costs for procurement and sales portfolio management of the trading houses and (retail/key) customer sales, as well as the trading margin, are priced in. The fee for using the grid remunerates the transmission of gas or electricity through the transmission and distribution grid structures. The grid utilisation fees are determined individually for each grid operator for a period of five years by the Federal Network Agency (BNetzA) through incentive regulation (see ARegV[2] ,StromNEV[3] and GasNEV[4]). Pursuant to section 19(2) sentence 1f. StromNEV enables the application of an individual grid charge (e.g. for acyclical grid usage). Any revenue lost by the grid operator is offset by a levy in accordance with section 19 StromNEV. If the energy is purchased using distribution grid structures, the concession fee for

[2] Verordnung über die Anreizregulierung der Energieversorgungsnetze (engl.:Incentive based regulation of energy grids)
[3] Verordnung über die Entgelte für den Zugang zu Elektrizitätsversorgungsnetzen (engl.: Regulation of carges for the access to electricity grids)
[4] Verordnung über die Entgelte für den Zugang zu Gasversorgungsnetzen (engl.: Regulation of carges for the access to gas grids)

the use of rights of way by the municipalities becomes due (cf. KAV[5]). The gas or electricity tax (cf. EnStG[6] StromStG[7]) becomes due to final consumers pursuant to section 3 No. 25 EnWG[8]. It should be noted that the prerequisites for tax exemptions for electricity from small installations will be tightened by the new amendment of the Energy Tax Act from 2018 [10].

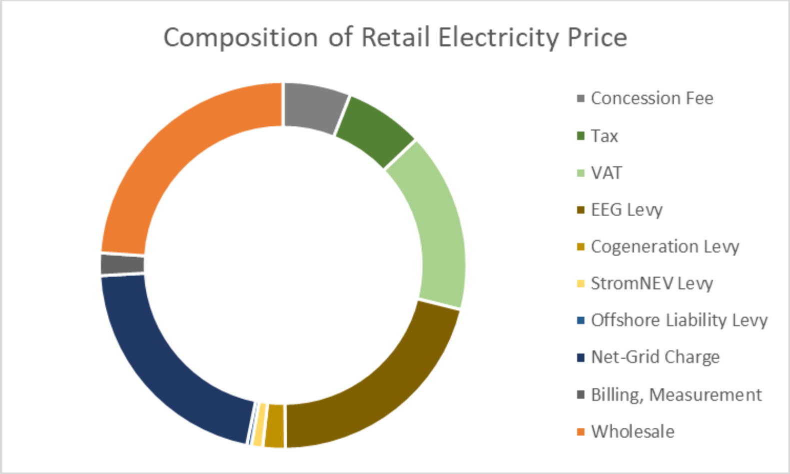

Figure 1: Composition of the Retail Electricity Price in 2016 according to [11]

In addition to the operation of the electricity grid, grid operators are also responsible for handling claims arising from the promotion of renewable energies, cogeneration (CHP) and demand-side management. The cash flows for a calendar year and the resulting allocations are forecasted ex-ante on an annual basis by the transmission system operators (TSOs) and determined by the BNetzA. At 68.8 €/MWh, the EEG[9] levy currently accounts for the most significant share of all levies. It compensates for the difference between the forecasted remuneration of renewable energy installations under the EEG paid out by the distribution system operators, the transaction costs, a liquidity reserve and the proceeds from the marketing of fixed-rate renewable energy installations by the TSOs (see EEG, EEV[10] and EEAV[11]). Similarly, the CHP levy finances the costs arising from the promotion of CHP. According to section 17f EnWG, the offshore liability levy is intended to compensate the costs arising from compensation payments from offshore wind farms not connected to the grid or disturbances in the connection to the grid. The provision of switchable charges is financed according to section18 AbLaV[12] by the AbLaV levy (not listed in Figure 1, not having been charged in 2016). The cumulated price components of the gas and electricity price are also subject to VAT at a rate of 19%.

[5] Verordnung über Konzessionsabgaben für Strom und Gas (engl.: Regulation for concession fees in the electricity and gas sector)
[6] Energiesteuergesetz (engl.: Act on energy tax)
[7] Stromsteuergesetz (engl.: Act on electricity tax)
[8] Gesetz über die Elektrizitäts- und Gasversorgung (engl.: Act on the electricity and gas supply)
[9] Gesetz für den Ausbau erneuerbarer Energien (engl.: Act on the expansion of renewable energies)
[10] Verordnung zur Durchführung des Erneuerbare-Energien-Gesetzes und des Windenergie-auf-See-Gesetzes (engl.: Regulation for the implementation of the act on the expansion of renewable energies and the act on offshore wind)
[11] Verordnung zur Ausführung der Erneuerbare-Energien-Verordnung (engl.: Regulation for the implementation of renewable energies regulation)
[12] Verordnung über Vereinbarungen zu abschaltbaren Lasten (engl.: Regulation on agreements for disengageable loads)

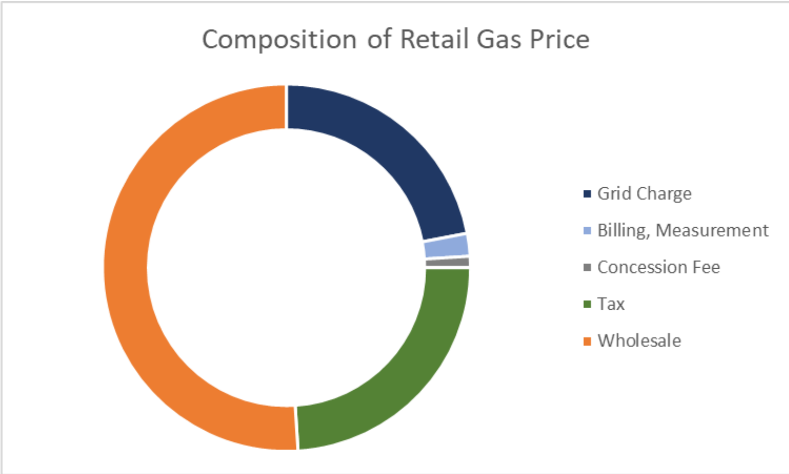

Figure 2: Composition of the Retail Gas Price in 2016 according to [11]

Retail customers are charged with taxes, fees and levies due to the purchase of electrical energy. According to the current legal framework, according to section 3 No. 25 EnWG this applies to all technologies that purchase electrical energy EnWG. This means that technologies such as pumped storage power plants, power to heat/gas (P2H/ P2G) and chemical storage facilities, which are solely used for the intermediate storage of energy and for sector coupling, are currently also assigned to this category. Figure 3 below classifies pumped storage power plants, P2H and P2G technologies, battery storage facilities and electric vehicles in terms of due taxes.

	[€/MWh]	Pumpspeicherkraftwerke	Power to Gas	Power to Heat	Batteriespeicher	Electromobilität
Stromsteuer	15,37 - 20,50	✓	✓	!	!	✗
Netzentgelte	individuell	!	!	!	!	✗
EEG-Umlage	68,80	✓	!	✗	✗	✗
KWK-Umlage	4.38	✓	✗	✗	✗	✗
Offshore-Umlage	0,25 - 3,88	✗	✗	✗	✗	✗
AbLaV-Levy	0.06	✗	✗	✗	✗	✗
StromNEV-Umlage	3.88	✗	✗	✗	✗	✗
Concession Fee	1,1 - 23,90	✓	!	✗	✗	✗

Figure 3: Regulatory disadvantaged technologies

This proves that sector-coupling technologies in particular are hampered by the current regulation. For technologies whose electricity procurement primarily serves the purpose of intermediate storage, levies to be paid are debatable. In addition, there is no possibility within the legal framework to waive the estimated network charge for installations that relieve the upstream grid levels. At this point the instrument of avoided grid charges should be mentioned, which was used in the past to cover this case. Due to the general reimbursement for decentralized generation, however, this instrument fell into disrepute and was abolished. The electricity tax is one of the most significant regulated price elements and due to the related inhibitory effect of important technologies in combination with the purpose of the tax it is highly questionable.

For the purchase of gas, grid charges apply to final consumers, such as gas-fired power plants, gas and steam turbines or gas engines. The energy tax is waived exclusively for the quantity of gas that is converted into electrical energy (see section 53 (1) EnStG). A proportionate relief is thus provided for plants whose primary energy input serves other processes (e.g. emission reduction measures, other thermal decoupling) (see section 53 (2) EnStG). The primary energy input for thermal extraction at power plants (CHP) is exempt from the energy tax for highly efficient plants with a monthly or annual utilisation rate of at least 70 % (see section 53a (1f) EnStG).

3. Methodical Approach

3.1 Overview

The European Market Simulation is based on macroeconomic optimization approach with the objective to minimize the overall costs of electricity generation. All market zones within the ENTSO-E area are taken into account (coloured in green in Figure 4). The integration of decentralized power plants as autonomous agents capable of acting in a European electricity market model on a high geographical resolution requires a modelling environment that enables distributed computing on a high-performance computer (HPC) with many computing cores. The simulation model developed in this paper uses mathematical optimization and dynamic programming to find the optimal unit commitment decision for the entire system. In addition to the spatially highly distributed renewables, hydrothermal power plant units are considered individually as independent entities. The complex technical properties require a mixed integer programming (MIP) formulation for thermal power plants, a dynamic programming (DP) approach for hydro power plants and a linear programming (LP) approach for the virtual power plants (VPP) containing detailed information on decentralized units. Even large scale HPCs are not suited for solving such problems. Therefore, the application of suitable decomposition algorithms is necessary. The given blockdiagonal structure in the unit commitment optimization problem of the power system for power plants with its coupling load constraints in each market zone imposes the use of Lagrangian Relaxation. This facilitates the contribution margin maximizing optimization of each entity using the Lagrangian multipliers which can be interpreted as wholesale electricity prices. Other methods, such as the Benders decomposition or Branch-and-Price (extension of the Dantzig-Wolfe decomposition by mixed-integer decision variables in the subproblems) have proved inefficient for this problem formulation.

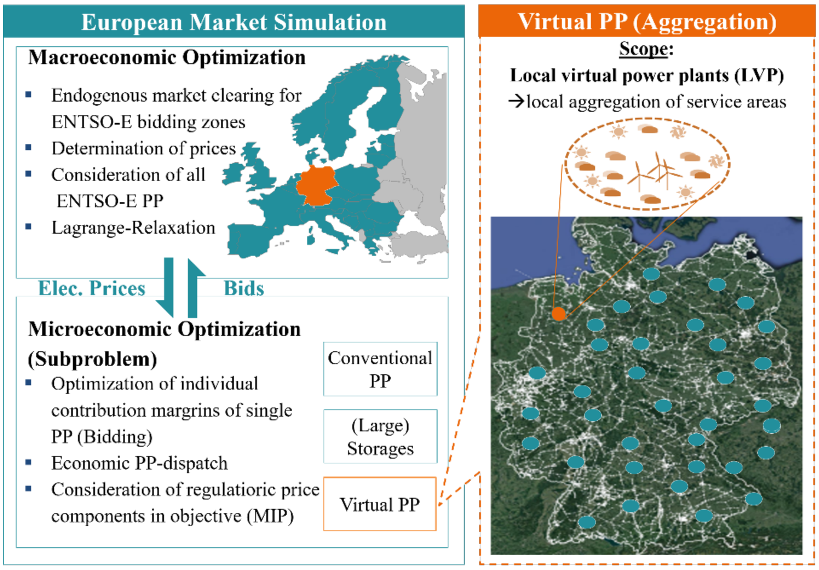

Figure 4: Overview on the Market Simulation including VPP

3.2 European Lagrangian Relaxation

The pan-European fundamental market simulation relies on a broad range of input factors. The hydro-thermal power plant fleet is a key element consisting of a database including 2000 – 4000 single units, depending on the scenario. This data is gathered using public available information, and proprietary databases including the status quo and planned projects [12]–[14]. As this paper focuses on a future scenario, the list is adjusted by expansion and (age-related) phase outs due to scenario assumptions. Techno-economical age-/size-/fueltype- related properties are then applied through use of publicly available data [15]. In addition to the installed capacities scenario assumptions regarding fuel/CO2-prices, cross-border capacities (Net Transfer Capacities; abbr.: NTC) and regulatory price markups are included (see section 4).

The unit commitment problem is decomposed into single unit commitment problems managed by a Lagrangian coordinator per market zone. These Lagrangian coordinators use a gradient approach to generate so called shadow prices, or Lagrangian multipliers, taking into account neighbouring market zones through market coupling. The endogenous market coupling is performed using an approach inspired by the market coupling algorithm used by the European energy exchange, the EUPHEMIA algorithm [16]. The endogenous consideration of market coupling is superior to multistage approaches in the generation of realistic market prices.

This price signal is then used by the market participants to optimize their contribution margin through their associated unit commitment decision. Thermal power plant models use a mixed integer programming approach to determine their commitment decision [17]. This approach is extended by additional constraints to implement the possibility of using power to heat applications and thermal storages to relax must-run constraints. The problem is solved in time slices with overlaps to ensure feasible calculation times. Hydro (pump) storage models use a dynamic programming approach. This allows optimization horizons covering a whole year, which is essential, especially for storages power plants, to schedule their seasonal inflows. Dynamic programming requires a discretization of the unit states with a trade-off in resolution versus memory requirements. The extension of the market model by the handling of virtual power plants as an aggregator for decentralized actors is the main objective within this paper and described in more detail in the following subsection.

The quantity bids are subsequently added up by the Lagrangian coordinators and the prices are adjusted depending on the deficit (overdemand or oversupply). This is repeatedly done until the relative duality gap (relative distance between the primal and the dual objective) or, as an upper bound, 100 iterations are reached. Any remaining deficit is then solved by a heuristic and a subsequent economic dispatch. The latter is performed using linear programming. This requires enough unit to be switched on as unit commitment decisions cannot be adjusted in a linear programming approach. Therefore, time steps characterized by an overdemand are re-optimized with a very high price incentive to ensure enough units are online. Following this repair procedure, the commitment decisions are fixed and the net position of the market zone, defined by the market clearing, are covered cost-minimal by the power plant fleet. This approach is depicted in Figure 5.

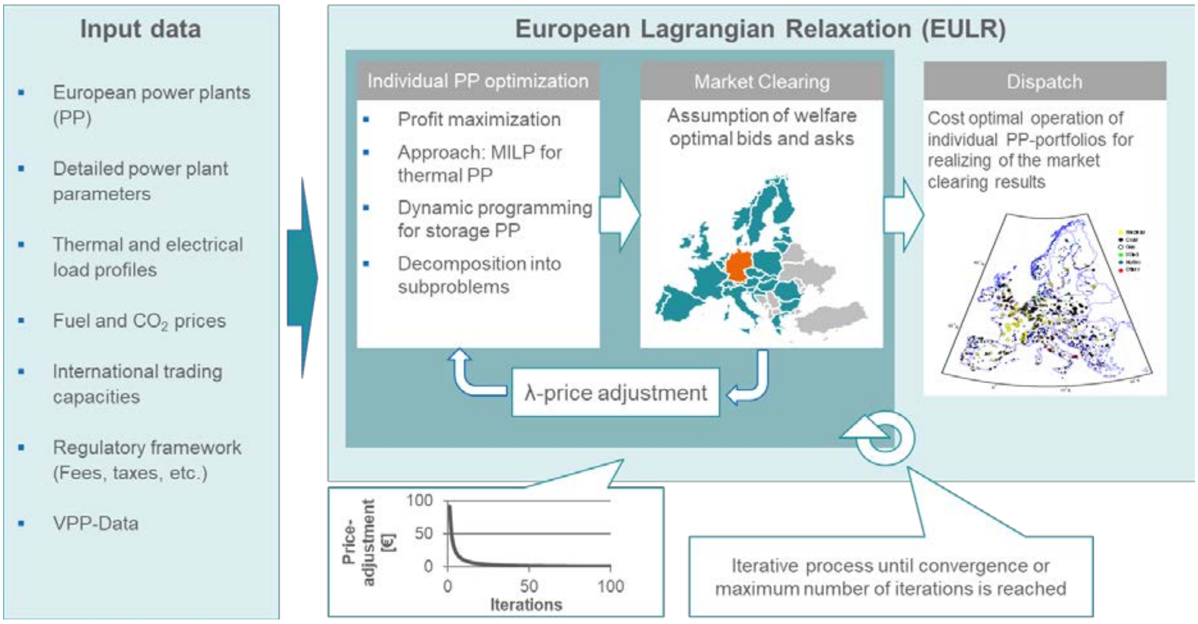

Figure 5: Process Flow of the European Lagrangian Relaxation

3.3 Virtual Power Plants

Aggregators, often referred to as Virtual Power Plants (VPPs), are promoted by some as being crucial for increasing the economically viable integration of DER into energy systems and for enabling the DERs to provide valuable services for electricity networks at scale. In this light, regulatory and policy bodies are discussing the value of aggregators and the need to support their competitiveness [18]. To address this relevant concept in future energy markets with a high level of renewable energies, the new actor type of VPP, who manages the purchase and sale on the electricity market for owners of decentralized technologies as a service provider, was incorporated into the framework. Beyond the possibility of considering VPPs, who operate regionally diversified technology portfolios, another scenario includes regionally concentrated (topologically related) VPPs (TPPs). In order to analyse the systemic potential for increased local load coverage through a better coordinated operation in local technology portfolios, it is advisable to focus on a scenario with TPPs.

The consideration of an exemplary German rollout of this scenario requires the reproduction of individual characteristics of supply areas and local technology portfolios, for example in order to evaluate regional effects and identify regions with high potential. This implies not only the knowledge of the consumer structure (households; commerce, trade and services (CTS); industry), but also a spatially highly resolved information base of regenerative DERs, electric vehicles, electrical and thermal storages and heat supply applications coupled to the electric network (CHP plants, heat pumps, etc.). Consequently, a regionally allocated data hub containing energy-related information across the aforementioned consumer sectors (approx. 20 Mio. residential, 2 Mio. CTS and 60,000 industrial buildings) is established, based on various publicly and commercially available data sets. The thermal and electric demand of these buildings as well as the composition of the portfolio of heat supply technologies can be parameterized to match a scenario frame and is linked to a pool of model-based load profiles and standard load profiles [19]. The combination of a regionally allocated register of renewable DER with the building-related energy data hub allows the mapping of local technology portfolios. These portfolios can be iteratively and economically optimized by TPP agents against the wholesale market prices (plus regulatory components according to section 2) within the market simulation process. The construction process and the structure of the optimization models are explained below.

The layout of the supply areas (operated by TPPs) is following the structure of the German high-voltage (HV) grid. Each region represents an area supplied by an HV/MV substation, whereby a total of approx. 4,300 areas are considered. The enormously high number of decentralized individual plants requires a reduction of complexity in the modelling of the TPPs, so that the computing time of the market simulation remains manageable (few days). The substations (HV/MV) therefore serve as aggregation levels for which all time series and installed capacities of the technologies under consideration are summed up. This procedure is carried out separately per sector for all building-related technologies (PV, CHP, heat pumps, storage, etc.) as well as for the regenerative DERs. In order to assess the regulatory influence on consumer sectors, the technologies are aggregated into individual clusters per sector and technology type within the aggregation. Figure 6 illustrates this procedure of building DER clusters for the technology portfolio of an exemplary area in Germany using GIS (geo-information system) data.

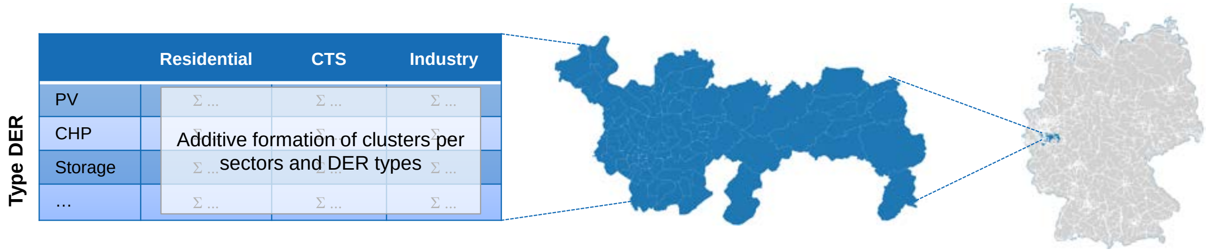

Figure 6: Scheme of aggregation of a regional asset portfolio sector and asset type specific clusters

In contrast to the MIP formulations of large power plants, the optimization problems of the TPPs are formulated as LPs, since restrictions that usually require binary variables (such as discrete power levels, minimum operating times) can be neglected due to the aggregation. The individual variable sets of the 4,300 optimization problems correspond to time steps of the year and different deployment options of the particular aggregated DER cluster. Specifically, the deployment options reflect the exchange of energy between technologies and the purchase and sale of energy on the wholesale market. The objective function coefficients are composed of the wholesale market prices plus regulatory components and fuel prices. The operation of the DER clusters is limited by the aggregated installed capacities. Further constraints are the coverage of the local thermal and electrical load and coupling constraints to ensure a joint participation at the wholesale market and load supply. The mathematical optimization is inspired by the developed scheduling algorithms in [20], [21].

In order to enable energy exchange not only within the lower voltage levels (medium and low voltage), but also within the high-voltage grid between individual areas, a further area clustering was introduced in the course of the investigation. This allows for an extended and yet rather local use of generation surpluses in individual sub-areas of the respective area cluster. Based on the 4,300 distribution grid areas, 400 regionally contiguous areas were identified, the regional extent and plant scope of which are visualized in Figure 7.

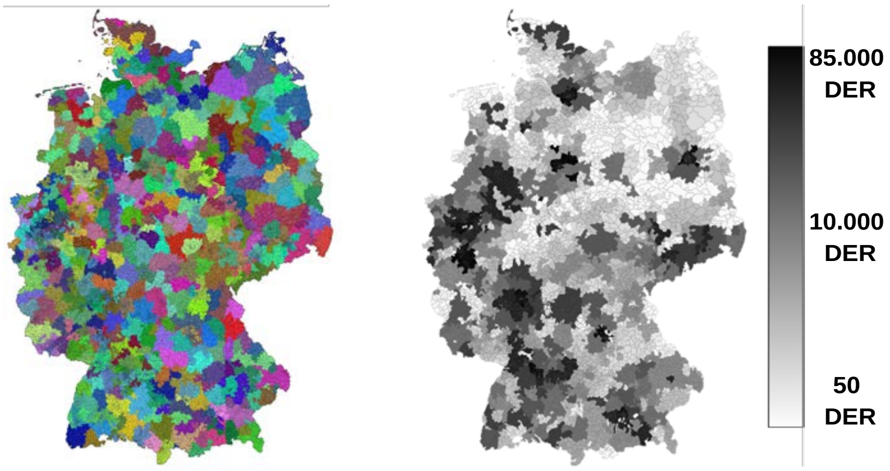

Figure 7: GIS visualization of the TPPs (left): each color corresponds to a TPP, right: Brightness value represents the number of installed DER (scenario-specific)

The regional extent of these clusters corresponds to typical sizes of the DSO supply areas in Germany. This additional and more realistic scenario was created in which instead of 4,300 TPP actors optimizing assets in small distribution network areas (MV, LV), 400 TPP actors optimise larger areas. These may correspond to DSO areas and may therefore be more suitable for assessing the economic viability of possible future business models. The layout of the areas and the constellation of subordinate supply structures, which are optimized by the TPP actors, are schematically shown in Figure 8. For each of these supply clusters, the individual variable sets of the substations (distribution grid area) contained in the supply cluster, consiting of the technology- and sector specific variables, are taken into account. On average, a modelled supply cluster contains aprox. 10 substations (distribution grid areas) whose individual optimization problems are linked to each other via coupling constraints for joint market participation and load coverage.

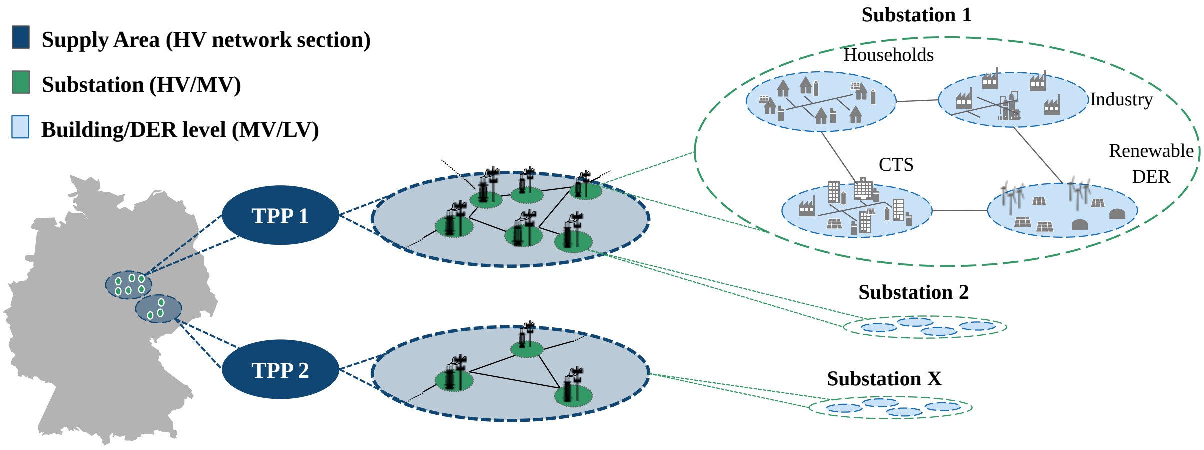

Figure 8: Access area and aggregation level of topological power plants

4. Exemplary Results

4.1 Overview Scenario

The calculations in this paper are based on a scenario for the year 2030 derived from the scenario B2030 out of the German grid development plan by the German TSO and the scenario “Sustainable Transition 2030” of the Ten Year Network Development Plan by the ENTSO-E [13], [22]. Assumptions regarding installed capacities per technology in each market zone/country (Figure 9) and net transfer capacities are defined.

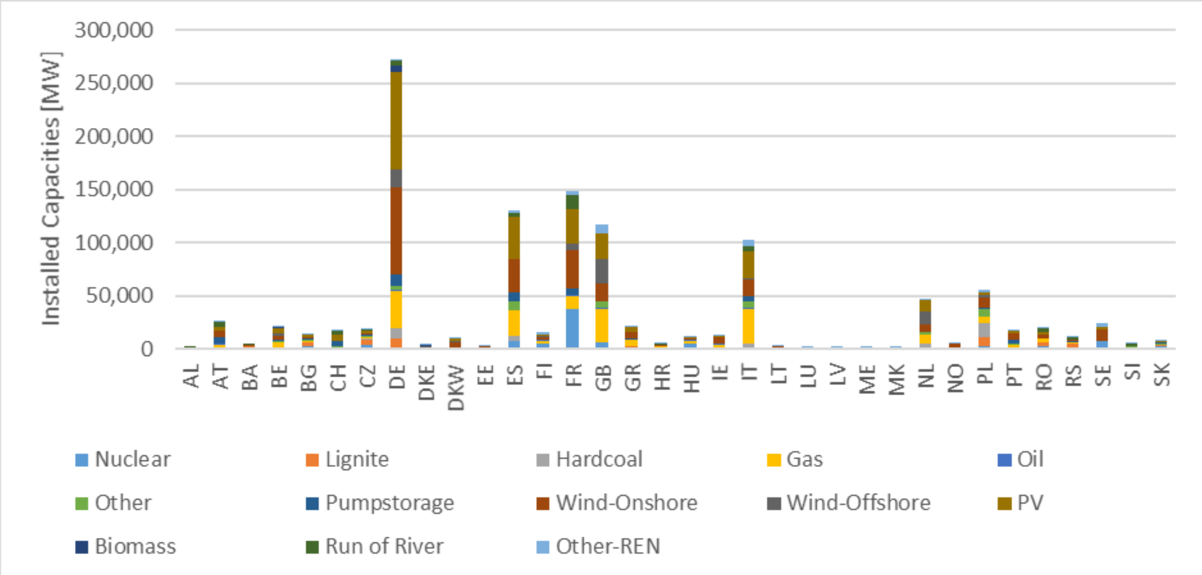

Figure 9: Scenario Assumptions regarding the Installed Generation capacities in 2030 according to [13], [22]

At DER level, 5 GW of decentralized battery storage (installed in buildings with PV systems) can be used by the TPP players. Further flexibility is available in the area of heat supply. The contribution to the supply of thermal demand (in TWh) is broken down by technology in the following bar chart (Figure 10). Heat supply technologies with coupling to the electricity grid (heat pumps, electric heaters, CHP systems) are equipped with thermal storage in the scenario, so that these can be used by the TPP players as flexible demand and generation. The thermal storage capacity is designed for one to two hours at full load of the individual installed power of the respective DER unit.

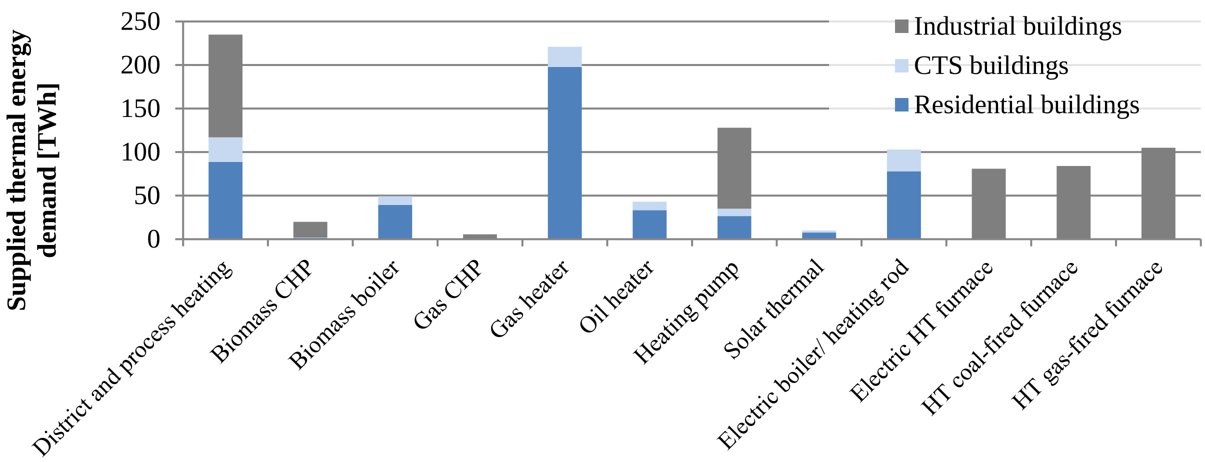

Figure 10: Structure of the heat supply in consumer sectors

4.2 Status Quo Regulation

In the following, the cost and revenue parameters within the TPPs are depicted for the case without regulatory price components, the base case scenario (Figure 11), and the case with regulatory price markups (Figure 12). The different technologies modelled in the TPPs can sell/buy power to the wholesale market, or use their generation for self-consumption purposes. The base case (Figure 11) withholds additional costs for the purchase of power (“regular” loads and power to heat), so that only the wholesale price (λ) is charged. All generation capacities receive market prices (λ), if the generated power is bid into the wholesale market. The curtailment is handled as a last resort following the priority feed-in directive of the EEG, therefore very high costs (300€/MWh) are estimated. To avoid random optimization results due to mathematical indifferences, the own consumption receives a price markup of 0.01 €/MWh, hence, own consumption is suppressed. Furthermore TPPs can use their flexibility due to electrical storages or demand side management potential to reduce their procurement costs.

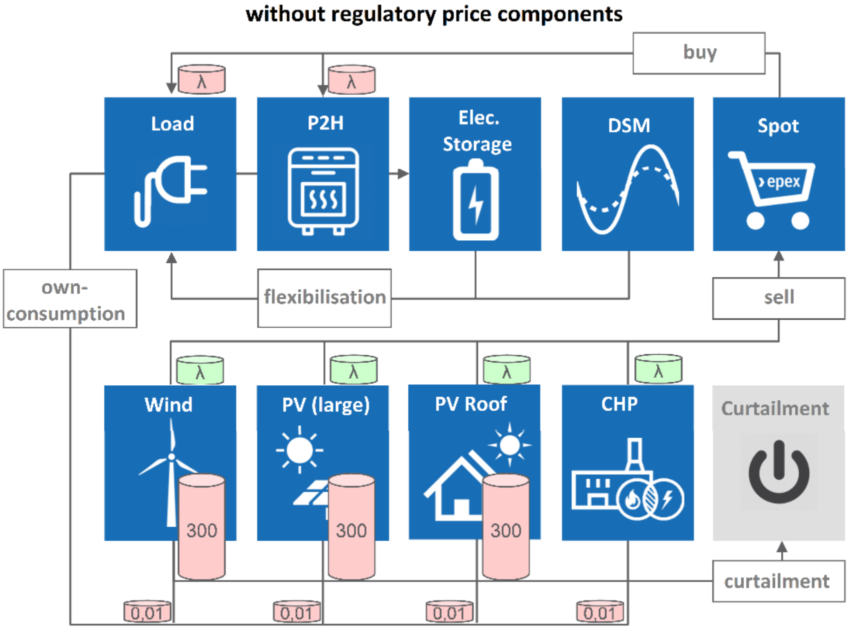

Figure 11: Cost and revenue parameters within the TPPs (without regulatory price components)

Applying the (current) regulatory induced price components introduced in section 2 to the TPPs leads to the price markups depicted in Figure 12. The price for power purchase as an end consumer is subject to regulatory price markups of 225 €/MWh added to the wholesale prices. Considered (decentral) generation capacities receive subsidies (market premias, feed-in tariffs, cogeneration-bonus) on top of the market price for their provision of power. It must be noted, that the so called 6-hour-rule on the payment of market premiums suspends, if the wholesale price is negative for 6 hours or more.[13] Curtailment costs for wind farms and not building related large PV farms are omitted due to direct marketing of these plants. Following the current market behavior, rooftop PV plants are not direct marketed, meaning that curtailment costs remain unchanged. Still, the own consumption of remote plants such as wind, not building related large PV and CHP plants is not funded. Therefore own consumption of this power is subject to 225 €/MWh regulatory costs (plus a 0.01 €/MWh markup to mathematical indifference reasons). In contrast to this, all regulatory price surcharges beside the EEG-levy (88 €/MWh) are omitted for the own consumptions of rooftop PV. Besides TPP, pump storages and central gas power plants face grid fees.

[13] Negative wholesale prices, a willingness to pay for energy supply, is observed increasingly in the last years. This is due to an increasing number of hours where conventional power plants, constrained by high opportunity costs or must-run obligations, would have to reduce their power output.

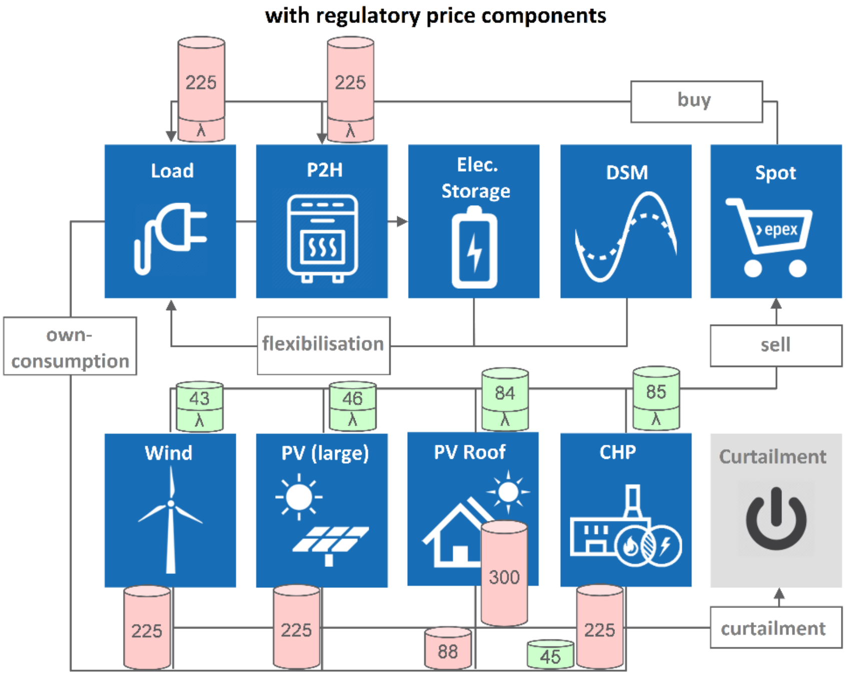

Figure 12: Cost and revenue parameters within the TPPs (with regulatory price components)

In Figure 13 the shares of each technology respectively of each category of market actor is shown. Most noticeable is the local load supply/ own consumption in TPPs of 37 TWh, which arises from the incentive for rooftop PV to supply local loads. The renunciation of directly marketed DER (wind and not building related large PV) leads to less negative prices and therefore to an increase of the minimal wholesale price from -109 €/MWh to -27 €/MWh. power to heat technologies reduce their dispatch significantly from 15.0 TWh to 9.7 TWh, because of regulatory burden. The decreased thermal energy of power to heat aggregates is substituted by gas-fired boilers. Pump storages also reduce their market attendance by 0.4 TWh due to regulatory burden.

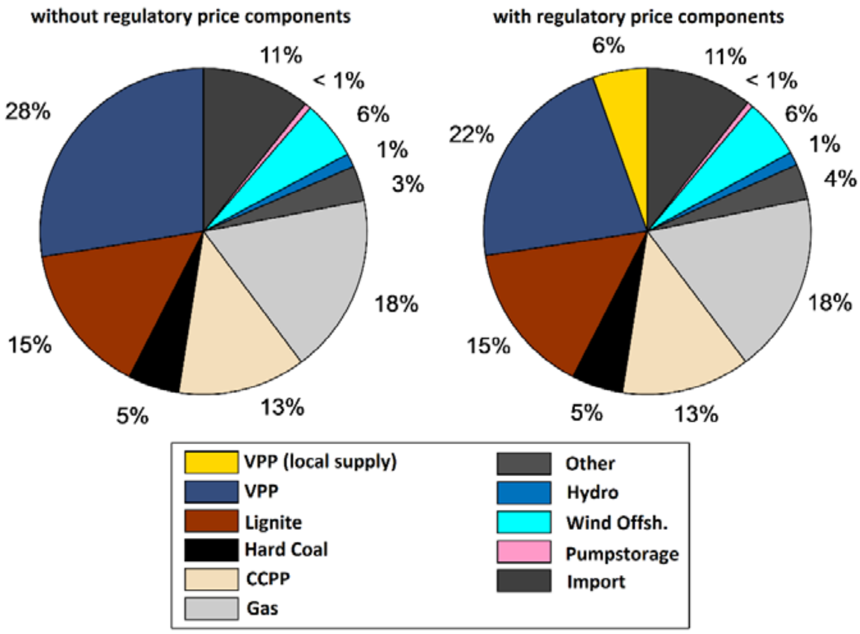

Figure 13: Technology specific market shares without regulatory price components (l) and with regulatory price components (r)

4.3 Test use case: Support of own consumption

An additional, local use of decentralized electricity production is indirectly coordinated by means of financial incentives through a hypothetical adaptation of the regulatory framework. In the previous calculation, only the purchase of electricity from PV roof systems was classified as own consumption and thus exempted from regulated price components, which was due to the typical consumer proximity of the systems. This (partial) exemption is subsequently to be guaranteed for electricity production from all decentralized plant types.

In terms of content, the tax exemption of local load coverage is based on the “tenant electricity model”, which is already being applied today: this provides regulatory relief for the electricity supplied by decentralized producers in residential buildings (e.g. CHPs or PV systems) to the final consumers (in particular tenants) of the building.

Remaining costs	Diminishing costs
• Production costs • VAT • EEG-levy	• Grid fee • Grid related levies • Electricity tax • Concession fee

The “tenant electricity model” extends the reduced purchase of locally generated electricity beyond conventional own consumption to consumption in multi-party houses. By analogy, the preferential treatment is to be applied to the entire TPP in the following investigations. Only the payment obligation for grid fees is to remain for electricity from remote wind energy and not building related large PV systems: for these technologies, distribution grid fees (but no transmission grid fees) continue to accrue, which are set at 50.4 €/MWh.

Two scenarios have to be differentiated: The application of the “tenant electricity model” to the TPP on HV/MV-substation area (local TPP) and the application to a cluster of neighboring HV/MV substations (regional TPP).[14] The relief of regulatory price components has significant impact to the local use of energy Figure 14.

While in the baseline scenario (“with regulatory price components”) only PV roof systems in physical proximity to consumers were partially exempt from taxation, wind turbines now participate with almost 23 TWh in the coverage of local loads due to the adjustment of the regulatory framework in the scenario with local TPPs. The load coverage by photovoltaics also increases (from 37 TWh to 42 TWh), which can be attributed to the regulatory incentive setting for not building related large PV. Previously, CHP plants only experienced an incentive to cover local loads in isolated hours of negative prices in order to take advantage of the KWKG[15] surcharges. As a result of the regulatory relief, their locally traded energy volume increases from 0.05 TWh to approx. 10 TWh. In the scenario with regional TPPs, a near doubling of the locally traded energy volume (approx. 130 TWh) can be registered. Wind turbines (59 TWh) in particular can reach even more consumers due to the less restrictive definition of own consumption and occupy a more dominant position in local trade. However, the participation of CHP plants (9.8 TWh) and battery storage facilities (from 0.9 TWh to 0.7 TWh) in local load coverage decreases slightly: this could be justified by the fact that they are forced out of local

[14] See section 3.3 for more details

[15] Gesetz für die Erhaltung, die Modernisierung und den Ausbau der Kraft-Wärme-Kopplung (engl.: Cogeneration act)

trade by generation from wind turbines, because local loads are covered on the basis of the variable costs of the individual generation technologies.

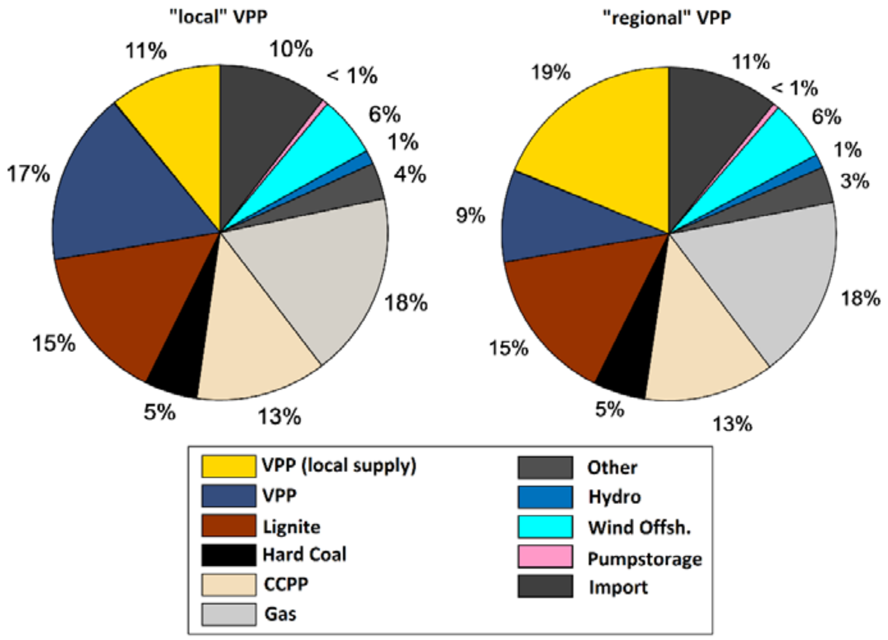

Figure 14: Technology specific market shares with a of very local (l) or more regional (r) promotion of own consumption

Figure 15 shows the locally covered load proportional to the total load of the TPP georeferenced on a map of Germany. The figure provides indications in which regions of the country the potential exists for the procurement of electricity from topological power plants through the setting of regulatory-induced incentives to decouple from the wholesale market. A large potential of local load supply can be found especially in northern Germany where large amounts of DER capacities are installed (mainly wind farms), and currently lead to a transport problem (north to south) in the German transmission grid.

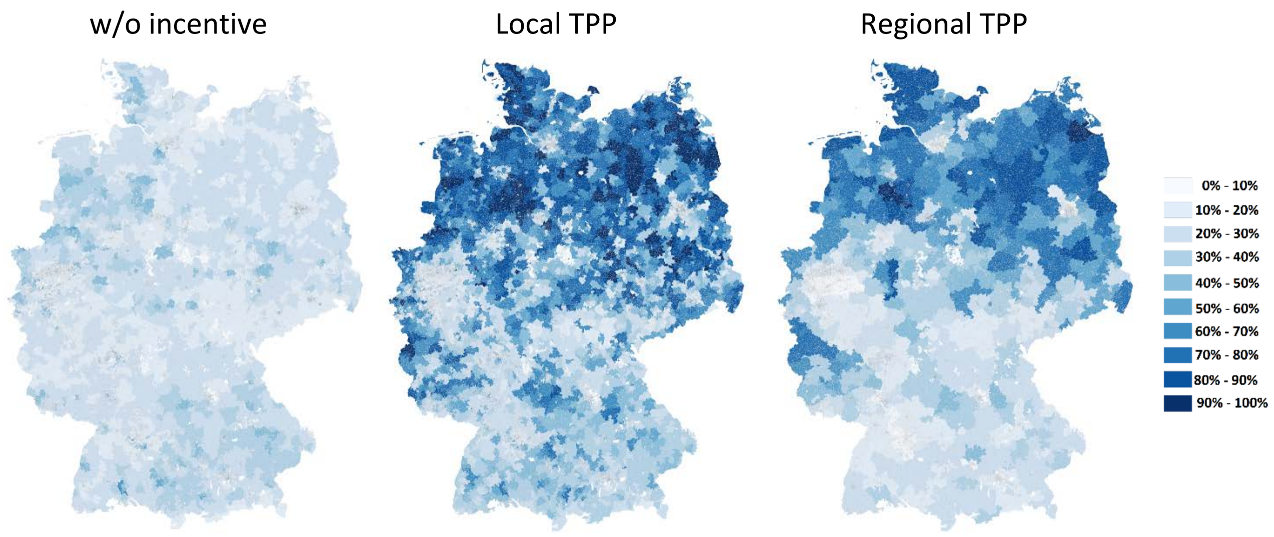

Figure 15: Map of Germany indicating the potential of local load supply based on the total load of TPP without incentive (l), with local incentive (c), with a regional incentive (r)

5. Conclusion and Outlook

The power system is characterized by long depreciation periods. A fast transition in the power system therefore requires detailed simulations of regulatory measures for future scenarios to cope with these systematic inflexibilities. The goal of this paper was to present a model which allows quantitative analyses to facilitate political decisions regarding regulatory measures needed to support (and not to burden) technologies which are needed in the energy transition. When applied to the German power market the results point towards a reduction of inhibitory levies and incentives to establishing local power markets. The correct quantification of economically-optimal financial incentives for local energy markets or relieving measures for power to heat appliances shall be subject to investigation of further scientific treatises.

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