Europe’s dystopia in pricing electricity

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Abstract

In 2022, the repetitive increasing gas prices have caused exorbitant electricity prices in most European countries. Economists argue that this is an evident consequence of Europe’s Internal Electricity Market functioning: for economic efficiency, the price is equated to the short-run-marginal-cost. However, the posted prices on the spot and futures exchange platforms do not merit the qualification of marginal cost prices. They are fringe prices, playing at the head of the electricity generation system, disconnected from the body of generated power. The exchange platform is not the European electricity market. Correcting Europe’s dystopia in pricing electricity request full transparency about the exchanges and their related cash flows. Public authorities and citizen groups, from local to national levels, should protest against the abuse of the marginal-cost-price concept by the electric power companies. A principled political choice for distributed renewable electricity prepares the future of full electrification based on the conversion of light, wind, water, and geothermal currents. This new reality requires a new electricity economics theory and practice, with proximity as priority ranking, investments paid via power purchase contracts, end-use prices tuned by reliability levels.

Keywords: marginal cost pricing, fringe pricing, European Energy Exchange EEX, reliability pricing, transparency

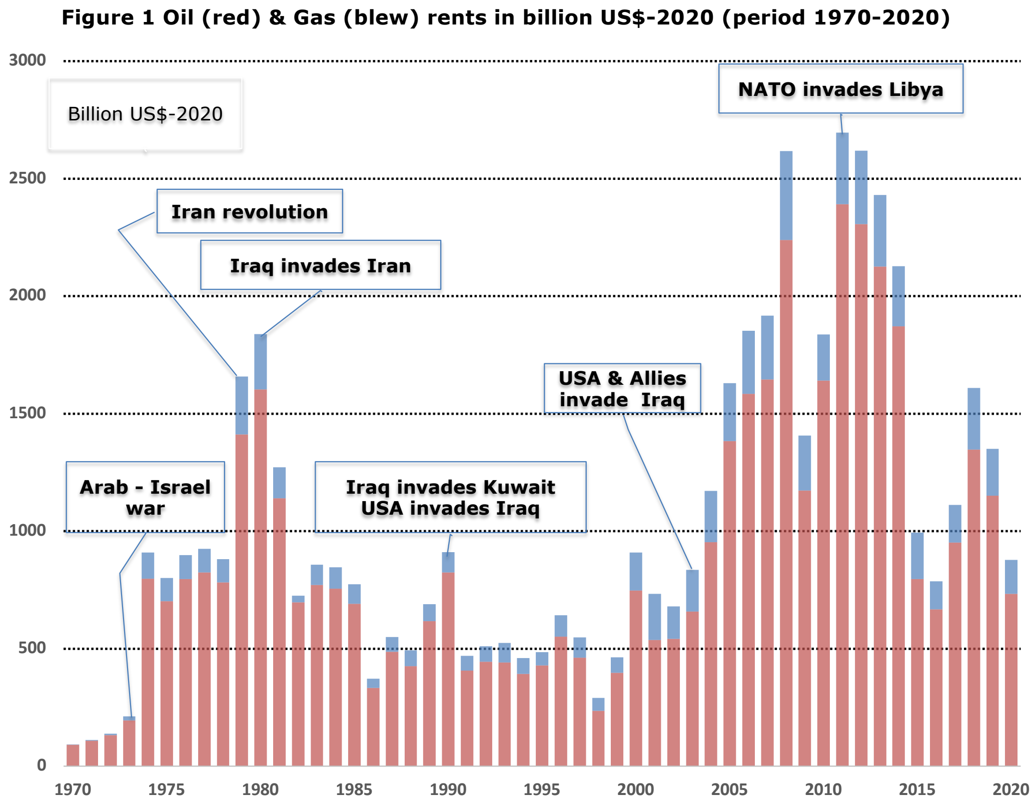
1. Introduction

Volatility in crude oil prices is high, mainly due to geopolitical conflicts involving petroleum exporting nations. After 1973, the dominant discourse was about ‘oil depletion’ and ‘wars for obtaining scarce resources’ (Homer-Dixon 1991; Peters 2004; Friedrichs 2010; Klare 2012). However, there is no physical resource scarcity. On the contrary, most fossil fuel resources will remain underground, by transforming commercial energy supply into mainly electric power harvested from ambient currents of light, wind, water and geothermal heat. There is no other future due to pending irreversible climate change (IPCC 2018, 2021).

Geopolitical energy conflicts are instigated for installing artificial scarcity in supplies by excluding oil & gas deliveries by ‘hostile’ nations, mostly governed by nationalistic authoritarian leaders, such as Iran, Iraq, Libya, Venezuela, Russia (Verbruggen and Van de Graaf 2013; Verbruggen 2022). By truncated market supply, oil & gas prices rise beyond US$100/barrel, generating significant rents for oil & gas exporting nations and excess profits for oil & gas companies. Figure 1 shows the volumes of yearly rents over the 51-year period 1970-2020. The added rents equal 52,544 billion US$-2020, on average 1,030 billion per year. The volatility ranges from a mere 92 billion in 1970 to 2,620 billion in 2011. Figure 1 points to the coincidence of top rents with military conflicts.

The oil & gas rent payments are transfers from net importing nations to net exporting nations, with multinational oil & gas companies capturing a significant share of the money flows. The bills land in, for example, European nations (except Norway), China, India, Japan, South Korea, New Zealand, and many developing countries. For the years 2021 and 2022, again top rents (above 2,000 billion) are expected, with a jump in the natural gas rents.

Figure 1: Oil (red) & Gas (blew) rents in billion US$-2020 (period 1970-2020) Source: author's calculation based on World Bank data and BP Statistical Reviews



The impacts of the extreme high natural gas prices are deleterious for the citizens and industries of net importing nations. Next to fossil fuel multinationals capturing excess profits, also European electric power oligopoly companies increase their profits. The impact on the electricity prices by high gas prices in European nations is the focus of this paper. Standard argument of the economist is "*Rising electricity prices due to rising gas prices is an evident consequence of Europe's Internal Electricity Market (IEM) functioning, where the price is equated to the short-run-marginal-costs. This kind of pricing is the efficient economic approach.*"

Given ruining energy poverty for millions European households, it is worthwhile to investigate the solidity of this argument. Section 2 briefly reminds technical attributes of electric current, and relevant for proper electricity economics. Section 3 on the economics of marginal cost pricing, focuses on electricity pricing theory and practice in two periods: ante 2020 when integrated national power companies supplied and tariffed electricity, regulated by public authorities; post 2020 when the Internal Electricity Market (IEM) was imposed with market-based instruments, such as the European Energy Exchange (EEX). The EEX houses the EPEX platforms for spot and futures transactions in electric power. In section 4 the prices posted at the EPEX spot market are characterized as fringe prices, quite different from the acclaimed economic-efficient short-run-marginal-cost price. In section 5 answers are probed on the question 'What can be done to correct the electricity pricing dystopia?' The conclusion (section 6) reviews the main findings.

2. Speedy and non-storable electric current

Electric power in Watt (Joule/second) is a transient current running over copper cables at high speed. Alternating current respects standards on frequency (50Hz in Europe) and on Voltage. Obeying the technical standards during every second of the year is necessary for delivering reliable, good-quality electricity to end-users. Being a current, power is not storable, i.e., a kWh produced is consumed within seconds of time.

Electric current is *secondary energy* converted from primary energy flows. So far, fossil fuels or uranium deliver pressurized steam or hot gas flows, at specific costs. For escaping climate collapse, and being the cheapest sources of electricity (IRENA 2022), renewable electricity from light, wind, water, geothermal flows is taking over. Hence, electric power systems are transiting from thermal generation plants, operated at command of human operators and causing specific fuel costs, toward renewable electricity generation plants mainly driven by natural currents of light, wind, water and heat with zero fuel costs.

The momentary demands for power constitute load curves aggregating the demand of millions of end-uses, with peaks when the aggregate use is high (Miller and Nam, 2022). Every second of the day and of the year meeting the fluctuating loads, is a considerable task for the numerous and various generation units. They operate synchronously in interconnected grids. The grids are instrumental in region-wide exchanges of electric power generated at distant locations. Power delivery can be complemented by load management (rearranging loads of end-uses), and by storage facilities (water pumped-storage; batteries; hydrogen). Sufficient power avoids brownouts and blackouts, making reliability of supply a valuable good. Different degrees of reliability merit different prices of supplied power (Chao 1983).

3. Economics of marginal cost pricing

In economics, 'marginal cost pricing' is key for reaching maximum efficiency (Becker 1971; Boadway 1979; Varian 1978). Economic graphs of a market show a demand and a supply curve, the latter being the aggregate of the marginal cost (MC) curves of numerous producers.

In cost analysis, one distinguishes long-run (LR) from short-run (SR). In the LR, production plant technology and capacity are changeable. In the SR capacities are a given, as are their fixed costs. Only variable costs are affected by the producer's quantity choice when meeting a momentary demand. Thus MC-pricing means short-run marginal cost (SRMC) pricing, and the theoretical optimal prices reflect variable costs, mainly fuel costs in power generation. Such proposal is a source of misunderstanding and contention between economic theorists and other practitioners such as engineers, marketing staff, sales staff, etc. about how fixed costs may be covered by a price only based on variable cost.

As straight textbook theory is, as messy are pricing practices. In real businesses, marginal cost pricing is little observed (Phlips 1983; Dorward 1987). Generation of electricity is the economic activity where marginal cost pricing has been explicitly proposed and pursued (Nelson ed. 1964; Turvey 1968; Rees 1976; Turvey and Anderson 1977; Vanlommel 1992). For an overview, two periods in European electricity economics (pre-2020 and post-2020) are considered

3.1 Marginal cost pricing of electricity supplies in centrally planned and operated power systems (ante 2020 situation)

In pre-2020 conditions, one company controls all power generation assets in a delineated service area. The area could be a nation, like EDF (Electricité de France) in France. The area also could be a share of the nation's territory, like in Germany. Before 2020, MC-pricing was pursued by some, like EDF led by M. Boiteux (1956), scientist and CEO during 20 years (1967-1987). The French large-scale system was top-down designed and operated. Generation and transmission were continuously monitored, functioning on command by central system and plant operators, with independent generation of power languishing.

Engineering-economic models governed investments in capacities, operations and pricing of electric power. The interlinked models answered the major engineering-economic questions on reliably meeting the demand for the non-storable electric current.

The investment theory uses isoquants, continuous ranges of capacity technologies, from high fixed / low variable costs (base-load) to low fixed / high variable costs (peak-load). Installed capacities each run their number of hours as least cost generator in the range, with equality of long-run marginal cost (LRMC) and SRMC, in an optimally composed generation system.

All plants function on command and 'in real time': over brief time spans (e.g., 15 minutes) available generation capacities are ranked in merit-order of their variable generation costs. The variable cost of the marginally loaded plant equals the SRMC of the integrated generation system, this being the theoretical proper kWh price of generation for all end-uses during that brief time span.

When the sequence – investment, operations, pricing – fits, the major issues of power supply achieve neat solutions: all end-users during short time intervals are treated equally via a SRMC-price, signalling the momentary opportunity cost of generated power. In an optimally composed and operated production park, revenues obtained via SRMC-pricing cover all costs of the system (Annex A). In practice, recalcitrant realities preclude theoretical optimality by several technical and economic variables hampering implementation of the theoretical stylized rulebook for operating electric power systems. Even with full access to all information and full control over all generation plants, it remains challenging to assess precisely the SRMC of an integrated power system. Moreover, in case of SRMC prices being available, such prices are only applicable when power delivered to customers is measured in quarter-hourly or hourly intervals. Since recently smart meters make the latter feasible for households too.

Before 2020, most electricity was sold via regulated tariffs, providing generous earnings to power generators. Part of the money went to investments in large-scale equipment; the other part was lavish, however not excessive, profit for private or public share-holders.

The economic optimality of SRMC-prices in electricity generation is contingent on two major factors. First, cost is more than private expenditure of a firm. External costs related to placement, functioning, emissions and waste of power plants are mostly not comprised in the firm's accounts and in the prices of delivered power. This omittance is generic in most economic sectors.

The second condition is that the integrated power generation system must be composed in an optimum way, such that SRMC also cover the fixed costs. The theoretical optimum assumes infinitesimal capacity additions or withdrawals, and stable production factor prices. Economies of scale, discrete sized generation units, sunk costs of long-living assets, and changing input factor prices destabilize the optimal composition of electricity production systems (Annex B).

3.2. Post 2020: From centrally planned and operated to market-based power supply systems

The European Commission (EC) intended the creation of an Internal Electricity Market (IEM) by substituting free market rules for vertically integrated supply structures. However, realizing workable competition in such tightly managed systems is contingent on a logical sequence of prerequisites, viz. proper harmonization of rules and conditions for all participants in the to become ‘competitive’ markets, reciprocity among participants, transparency of the institutions and activities, unbundling of the main functions (generation, transmission, distribution), and firm guidance and supervision by excelling public regulators.

The EU regulatory packages (1997, 2003, 2009) could not fully impose the prerequisites on the member states, and competition remains incomplete with influential oligopolies and remaining state-owned companies (e.g., EDF, Vattenfall).

The announced merits were cheaper electricity as a result of competition among producers, i.e., the overall power generation systems would generate cheaper power which would then be delivered following the rule p = MC.

The Directive (EC 1997) prescribed deconstruction of vertically integrated electricity monopolies in the EU. However, EU member states implemented the directive at uneven pace and intensity. By M. Tatcher’s politics (1979-1990), the UK has been unbundling and privatizing the public-owned Central Electricity Generation Board in the 1990s. France persistently delayed the deconstruction and privatization of EDF; in 2022, president Macron announced to raise the state’s share in EDF from 84% to again 100%. Reciprocity, an essential attribute of the IEM, has not been respected. Competition among the former national companies is limited to skirmishes. Common interests (like in the EU’s Emissions Trading System, or about state aid guidelines) prevail, with EURELECTRIC supervising the club.

Parallel to sector liberalization, Independent Generators of Own Power (IGOP)[1] multiplied in numbers to the millions, mostly with rooftop photovoltaic panels. Cooperatives and SMEs in renewable generation emerged. In 2014, the EC choked the growth of small-scale renewable energy projects by new state-aid guidelines, giving priority to large-scale projects of the incumbent power oligopoly companies (Verbruggen et al. 2015).

Actually, the European electricity business is a kaleidoscope of mainly oligopoly multinationals, no longer constrained by national boundaries. System Operators (SO) assumed operational dispatching of generation units and supervision over transmission operations in the SO service area.

In theory, a perfect competitive market could deliver similar MC-prices as a perfectly planned and operated centralized system. Neither perfect markets, nor perfect planning exist in reality. Simshauser (2020, section 2.1) provides a neat overview. Hence, how far real arrangements and facts may deviate from the theoretical model for SRMC to obtain practical validity?

Power exchanges, platforms for selling and buying electricity, emerged and post prices for electric power. The European Energy Exchange (EEX), also trading carbon emission permits, is the most active one. Spot and future electricity packages are traded. The spot covers day-ahead and intraday transactions; futures span longer periods up to months and year-ends. Over time, the power trade section (EPEX) improved the spot trade mechanisms, such that up to 15-minute intervals are an option, and that adjustments in purchasing capacity are feasible up to shortly before delivery of the contracted volume. In 2021, “over 300 companies traded 621 TWh of electricity on EPEX SPOT representing roughly 30% of the European electricity consumption” (EEX 2022). The exchange members are classified in five groups: Utility/Aggregator; Local Supplier/Consumer; Trading Company; Transmission System Operator; Bank and financial service provider. It is not specified which part of the trade is physically materialized. Transparent information

[1] IGOP as general and neutral term (Verbruggen 1997) is preferred above ‘prosumers’ (Schleicher-Tappeser 2012) or ‘co-providers’ (Geelen et al. 2013). The adjective independent is added to distinguish from joint ventures between incumbent power companies and industries that house on site a shared (often cogeneration) power plant.

on who buys from whom which volumes, and on financial transfers related to the trade, are not provided.

The positive effects of liberalizing electricity generation are several, such as more opportunities for Independent Power Producers (IPP) and for IGOP adding a pinch of competition; enlarging the economic scope to technical reality (electric power is continuously swapping over the European continent); substituting an European-wide integration for separated nationally integrated power systems provides economies by a larger and more diverse merit-order stack of capacities, by reducing overcapacities, by obtaining higher reliability at lower costs.

Nevertheless, the incumbent electric power oligopoly companies continue to dominate the electricity business in Europe. While this fact opens a large window for investigation and evaluation, only the aspect important for the power pricing issue is mentioned here: the capability of oligopoly companies to control large industrial sectors, and extract above-average up to excessive profits, especially in the energy sectors with a captive demand.

4. Characterizing the prices posted at the EEX exchanges

The EPEX posted spot prices of electricity do not meet the standard for representing proper marginal cost prices. This judgment is not based on observing small or large, reasonable deviations from the ideal marginal cost price. There are structural arguments for rejecting present EPEX spot prices as economic efficient prices applicable on the electricity consumption of customers.

First, the natural gas prices have an exorbitant impact on the EPEX spot prices. The disproportionate gas price hikes also uproot the balances in the composition of the electricity generation parks in Europe. At the extreme high gas prices, the parks are very distant from workable approximations of optimal composition. A balanced composition (not necessarily the theoretical optimum) is an indispensable validity condition for the economic efficiency trump of short-run-marginal-cost pricing of electricity. Quod non.

Second, the EPEX spot market handled 621TWh in 2021, roughly 30% of the European electricity consumption (EEX 2022). This limited share of the total electricity volume covered by EPEX spot is another structural argument for rejecting the spot prices as valid representatives of robust marginal cost prices (annex B).

EPEX spot price not meriting the qualification of marginal cost prices, what really do the posted prices reflect and what name is telling their content and function?

Before answering this question for EPEX spot, one can learn from another market organized by EEX, the market of emission permits of the EU Emissions Trading System (ETS). Of course, the product is very different from electricity: an ETS permit gives the right to emit one ton of CO_2-eq emissions. The trade in permits generates daily prices (EMBER), vaunted as proof that the 'market is working'. However, Emissions Intensive Trade Exposed (EITE) industries receive free permits for all (with some +/- noise) their emissions. Hence, the EEX ETS price of a permit is a 'fringe price': it operates at the margin of the emission activities, but does not cover, nor affect, the body of the emissions (Verbruggen 2021: chapter 6). Such price is largely speculative, and allows the oligopoly companies to earn significant rents, excess profits. For example, in phase 1 of the EU ETS (2005-2007) all emission sources got a free oversupply of permits. Yet, speculative trade activity drove the price at some moments up to €30/permit on the EEX exchange platform. This speculative fringe price was the signal for the European electric power companies to cash billions of so-called windfall profits (Sijm et al. 2006), actually excess swindle profits (Verbruggen 2008). The EEX exchange platform for ETS permits is not a carbon market.

It is appropriate to qualify the EPEX spot prices as fringe prices: they play at the head of the electricity generation system, disconnected from the body of generated power. The EPEX spot platform is not an electricity market. The spot activities organized by EPEX have extended their role in supporting the reliability of electric power supplies in Europe. This positive element of the EPEX spot platform is a substitute and complement for the reliability care by national power systems.

EU's oligopoly power companies use EPEX spot prices as opportunities for extracting excess profits from their captive customers. This practice is comparable to robbery.

Considering the positive and negative role of EPEX spot, the policy problem is: how to throw out the bathwater and save the baby?

5. What can be done to correct the electricity pricing dystopia?

One wants answers for immediate action, while it is also recommended to develop a strategic view on electricity pricing for the future in a fast-changing electricity world.

Prior to actions in the electric power sector, deflating the gas prices would relieve the burdens on the European economy and on the livings of people. The deflation requests another energy geopolitics, a precarious issue beyond the focus of this paper.

Immediate action

First, impose full transparency about the actors, buyers and sellers, on the EPEX spot and futures platforms, and about the transactions, the settled prices and volumes, the physical trade, and the money flows connected to transactions and trade. Clarity about money flows, about who pays and who cashes, is key for the follow-up of the energy users' extortion. Price is ephemeral, cashed money is a lasting asset.

Transparency was one of the selling chips when enacting the EU directive on the internal electricity market (EC 1996). The secret decision-making and deals occurring inside the incumbent integrated power companies had to be replaced by a fully transparent open market system, to the advantage of the electricity customers.

Transparency may reduce speculation and the robberies by oligopoly power companies. Transparency is requested when political authorities want to intervene for truncating the impact of EPEX spot activities beyond their role in supporting the reliability of European electricity supplies.

Second: public authorities and citizen groups at all levels (local, provincial, national) should address the electric power companies, active on their territory. The address is a protest against the ongoing extortion by abusing a respected economic concept (marginal cost pricing) which does not hold. The abuse erodes the legitimacy of electric power companies.

Third: for escaping climate collapse, domestic, industrial, transport … activities have to be driven by electricity, harvested from renewable currents (mainly light, wind, water). The technologies to convert the currents in electricity are small-scale, affordable, and further improving in performance and decreasing in cost. Today already, they generate the cheapest kWh ever done in the history of the electricity sector. The public authorities and citizen groups at all levels should prioritise investment and set-up of local energy communities, cooperatives, smart grids, efficient end-use equipment, advanced load management to guarantee adapted reliability for specific end-uses, and more. This is the bridge to safe and more equitable societies. The prevalence of either distributed or centralized renewable electricity is a principled political choice in guiding future development of the power systems.

Prepare the future

Today, the discourse on electricity pricing is based on electricity generation systems consisting of mostly thermal power plants (annex A and annex B). Such plants ramp up or slow down the electricity they generate at operators' command. Capacity slices are characterized by their specific fuel consumption and fuel cost, allowing the set-up of merit-order rankings

When electricity generation depends more and more on renewable energy currents (wind, light, water), nature is commanding power generation, man can only bypass the currents, i.e., reject nature's offer. Natural currents do not use fuel; hence, the fuel cost is zero. Merit-order ranking, optimal composition of power generation parks, short-run-marginal-cost pricing fall apart. Fully new pricing concepts, theory and rules are due.

As substitute for the merit-order ranking, a "proximity principle" should be applied: the appropriate renewable electricity supply source nearest to the demand sink gets priority for delivering its generated power to the end-use. Rewarding the investments in renewable electricity generating capacities, is based on delivered kWh at a fixed tariff, guaranteeing a modest return on the investment over the expected lifetime. Hourly pricing of purchased electricity requests the overall availability of smart meters, also supporting the management of the customer's electricity use. Sales prices are differentiated by demanded reliability levels for various levels of consumption.

6. Conclusion

The impact on the electricity prices by high gas prices in European nations is the focus of this paper. Standard argument of the economist is "*Rising electricity prices due to rising gas prices is an evident consequence of Europe's Internal Electricity Market (IEM) functioning, where the price is equated to the short-run-marginal-costs. This kind of pricing is the efficient economic approach.*" It is investigated whether this proposition holds.

The study of marginal cost pricing of electric power is split over ante-2000 and post-2000 situations. Ante-2000, most electricity in Europe was generated and delivered by national vertically integrated companies. MC-pricing was considered by some companies, EDF (France) by excellence. The developed theory and models in computer programmes provide insight how to apply MC-pricing on electric current, being non-storable, utterly fast, and critical precise in frequency. The technical issues are described in the annexes A and B.

In theory, a perfect competitive market could deliver similar MC-prices as a perfectly planned and operated centralized system. Neither perfect markets, nor perfect planning exist in reality. Hence, how far real arrangements and facts may deviate from the theoretical model for SRMC to obtain practical validity?

There are structural arguments for rejecting present EPEX spot prices as economic efficient prices applicable on the electricity consumption of customers.

First, the natural gas prices have an exorbitant impact on the EPEX spot prices. The disproportionate gas price hikes also uproot the balances in the composition of the electricity generation parks in Europe. At the extreme high gas prices, the parks are very distant from workable approximations of optimal composition. A balanced composition (not necessarily the theoretical optimum) is an indispensable validity condition for the economic efficiency trump of short-run-marginal-cost pricing of electricity. Quod non.

Second, the EPEX spot market handled 621TWh in 2021, roughly 30% of the European electricity consumption (EEX 2022). This limited share of the total electricity volume covered by EPEX spot is another structural argument for rejecting the spot prices as valid representatives of robust marginal cost prices.

It is appropriate to qualify the EPEX spot prices as fringe prices: they play at the head of the electricity generation system, disconnected from the body of generated power. The EPEX spot platform is not an electricity market.

EU's oligopoly power companies use EPEX spot prices as opportunities for extracting excess profits from their captive customers. This practice is comparable to robbery.

What can be done to correct the electricity pricing dystopia? This difficult question is answered with three immediate actions, the third linked to preparing the future.

First, request full transparency about the transactions occurring on the EPEX spot and futures platform. Transparency was an important attribute promised by the Internal Electricity Market directive in 1996. Second, local and national actors should address the electric power companies, active on their territory. The address is a protest against the ongoing extortion by abusing a respected economic concept (marginal cost pricing) which does not hold. The abuse erodes the legitimacy of electric power companies. Third, the public authorities and citizen groups at all levels should prioritise investment and set-up of local energy communities, cooperatives, smart grids, efficient end-use equipment, advanced load management to guarantee adapted reliability for specific end-uses, and more. This is the bridge to safe and more equitable societies. The prevalence of either distributed or centralized renewable electricity is a principled political choice in guiding future development of the power systems.

The future electricity supplies will be mainly converted ambient natural currents such as light, wind, water. They do not deliver on command and their fuel costs are zero. This makes the electricity economics as applied (also in this paper) obsolete. A new electricity economics theory and practice is necessary. Some hints are provided in section 5.

Annex A: Least-cost electricity generation

This annex describes least-cost electricity generation in formal terms.

Given:

- An electricity generation company owns numerous (Ω) power plants with differing weights of fixed and of variable costs, adapted to their expected number of activity hours during the year (8760 hours).
- The generation system of the company is optimally composed, i.e., the right capacities (kW) of base, intermediate and peak load plants are available for being loaded to generate electricity e (kWh).
- The Ω plants are ranked in a merit-order stack from least to highest fuel cost for generating electricity, thus base-load plants come first, followed by intermediate load, with peak-load plants at the tail.
- Electric current is non-storable. Fluctuating loading of the various plants in 'real-time' covers the fluctuating demands for electric power 'on the spot'. Leaving technical and operational details aside, we adopt hourly as sufficient real-time.
- During every hour of the year the company will meet the total demanded quantity of E kWh for avoiding blackouts.

For minimizing operating expenses $\Sigma_i C_i(e_i)$, the proper quantities $e_1, \ldots, e_k, e_m$ ($m \leq \Omega$) of electricity generated by the various plants ($1, \ldots, \Omega$) are identified.

The constrained cost minimization is formally:

Min.! $\Sigma_i C_i(e_i)$

Subject to: $\Sigma_i e_i = E$ [total demand is covered]

$e_i \leq e_{i,max}, \forall i$ [no plant generates more than its available capacity]

This delivers the Lagrange function: $L = \Sigma_i C_i(e_i) - \lambda\{\Sigma_i e_i - E\} - \Sigma_i \mu_i\{e_{i,max} - e_i\}$

First order conditions for minimizing L are the first derivatives to the unknown variables set equal to zero and the complementary slackness condition for the inequality constraints, or:

$\forall i \mid \quad MC_i(e_i) = \lambda - \mu_i$

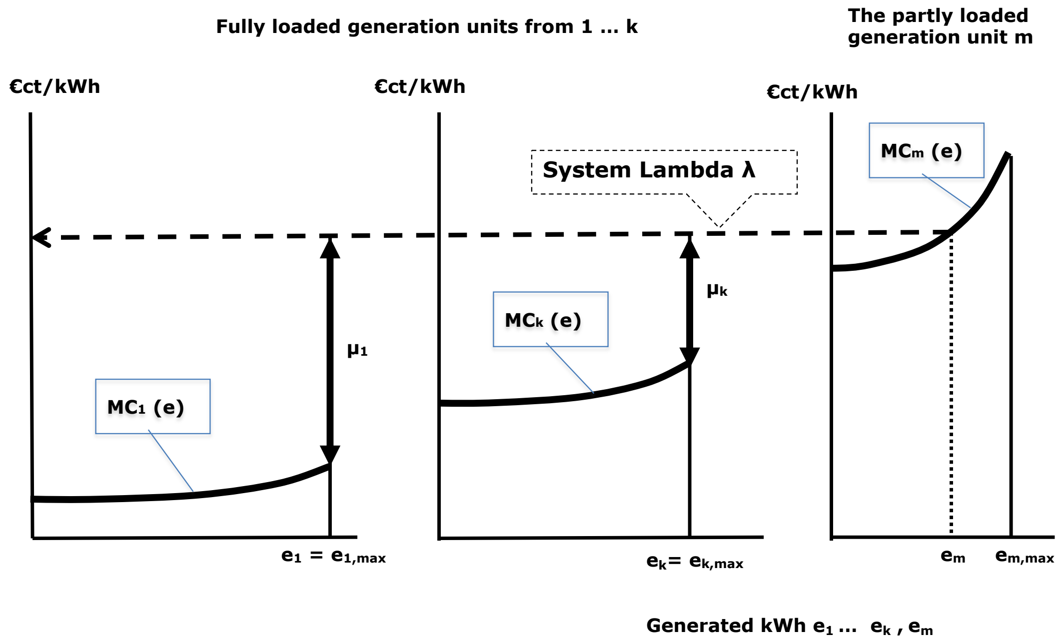
$\Sigma_i e_i = E$

$\forall i \mid \quad \mu_i\{e_{i,max} - e_i\} = 0$ [i.e.: $\mu_i = 0$ when $e_i < e_{i,max}$; otherwise $\mu_i \neq 0$]

The last *loaded* generation plant m of the stack is partly loaded $\{e_m < e_{m,max}\}$, at marginal generation cost λ, called 'system lambda λ' of the considered hour. It is the company's system marginal cost for producing one kWh extra, and this value λ will be charged for all E kWh supplied to end-users during the considered hour. Hence, the earnings by applying SRMC-pricing equal $\lambda * E$.

Forgoing plants in the merit-order stack are fully loaded $\{e_i = e_{i,max}\}$, delivering kWh at their lower specific marginal cost-price $\{\lambda - \mu_i\}$, with $\mu_i \neq 0$. This implies that the company earns μ_i per kWh generated by plant i, or in the aggregate $\Sigma_i e_i * \mu_i$ on top of the fuel costs of these units. Figure A.1 shows the results for three generation plants, active during the specific hour.

Figure A.1: Marginal Cost curves of 3 plants visualizing the Lagrange results: Nr.1 of the merit order (base-load); intermediate Nr.k; marginal loaded unit Nr.m



When the company's generation system is optimally composed, the aggregates Σ_i $e_i * \mu_i$ (summed over the 8760 hours of the year, and over the lifetime of the plants) suffice for covering the fixed costs of the plants.

Recalcitrant realities preclude theoretical optimality

The above description of the functioning of centrally controlled electric power generation systems with all units on command is a single hour snapshot to explain SRMC of electric power. Yet, modelling least-cost generation in real-live electricity systems is more complicated. Consecutive hours are interdependent, because thermal power plants have start-up costs, and technical constraints limit ramping capacity rates of various units. Reserve capacities are spinning for the requested reliability of supply. Shipping power from the generation plants to end-use points add network costs, while congested lines may have an impact on the functioning of generation systems (Rayati and Teneketzis, 2022). In addition, some 'must run' or inflexible units claim priority over cheaper plants in the merit order.

Annex B: Optimal composition of an electricity generation park

This annex describes the economics of composing an optimal electricity generation park.

An electricity generation park is constructed to meet the hourly loads of customers in a given service area. A load equals the added gross demand (nett demand + losses on power lines and in voltage transformers) during one hour of the year (8760 for a standard year). Loads are inventoried chronologically from January 1^{st} at 01 until December 31^{st} at 24. Load duration curves visualize relevant attributes of the loads, such as yearly load factor, peak loads. A load duration curve ranks the hourly chronological load information from highest to lowest load (fig. B.1). The theoretical arguments are easier to show on the smooth load duration curve.

The goal of the firm is to minimize total costs (capital investment and operation) by selecting the most efficient technologies for delivering power during a particular number of hours in the year. Isoquant is the economics' concept for handling technology choice. The isoquant represents the various combinations of production factors for delivering a same quantity of product. Constant returns to scale are assumed. A technology is defined by a (E_i, K_i) pair, where K_i is the annuitized investment + staff cost of a unit capacity (1 kW) and E_i is the energy (fuel) cost of producing one kWh.
Figure B.1 shows a standard isoquant. By reason of efficiency, the curve is convex. Let $E = \alpha.K^{\delta}$ represent the efficiency frontier, with $\alpha > 0$ and $\delta < 0$. Composing the production park is selecting for each 'layer' of the load the least-cost technology. Adopting constant returns to scale and a continuous technology frontier, the choice of the least-cost technology for any layer is independent of the decisions with respect to all other layers of the load diagram.

The total costs of a layer equal E.t + K, with t = operational time of the capacity (number of hours). The technology choice is stated formally as:

$$\text{Min.! } (E.t + K) = \text{Min.! } (\alpha.K^{\delta}.t + K)$$

1st order condition: $\alpha.\delta.K^{\delta-1}.t + 1 = 0$

2^{nd} order condition: $\alpha.\delta.(\delta-1)K^{\delta-2}.t > 0$ is OK, because $\alpha > 0$ and $\delta < 0$

The first order condition shows $K^* = \left(\frac{-1}{\alpha.\delta.t}\right)^{1/\delta-1}$ and $E^* = \alpha.\left(\frac{-1}{\alpha.\delta.t}\right)^{\delta/\delta-1}$

This defines the optimal technology as a function of the layer-index t, i.e., the number of hours the elementary capacity will have to produce.
Substitution of the results in E.t + K provides the minimum total costs to produce a one kW layer during t hours, being

$$\left(\frac{\delta - 1}{\delta}\right).(-\alpha.\delta.t)^{-1/\delta-1}$$

This outcome is independent of the shape of the load duration curve. Because $\delta<0$, it follows $0 < \frac{-1}{(\delta-1)} < 1$, or total cost increases less than proportional in function of time.

When the production park is optimally composed, SRMC and LRMC are equal. This is shown graphically in figure B.1. It shows an additional demand for 1 kW during the t* peak hours of the year. Either a 1kW layer L-S of new capacity is inserted in the park for generating the extra demand. Then, the capacity layers on top of this layer continue to operate as before.

The cost of adding a new layer capacity and run it during t* hours, is found above as:

$$\left(\frac{\delta - 1}{\delta}\right).(-\alpha.\delta.t*)^{-1/_{\delta-1}}$$

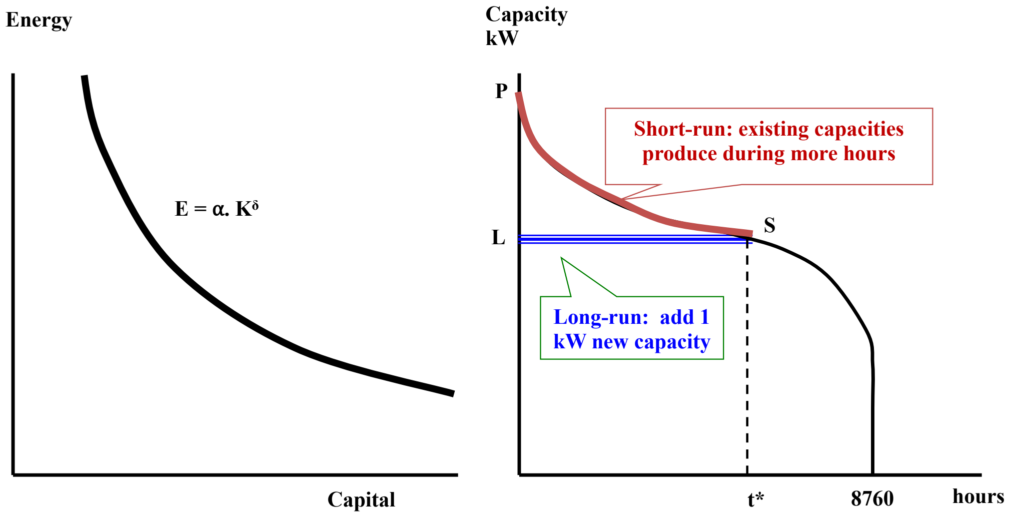
When no new layer is added, existing plants on top of L-S, have to fill the extra demand P-S by working more hours than before. The cost of this approach equals:

$$\int_0^{t*} E.dt = \alpha.\left(\frac{-1}{\alpha\delta}\right)^{\frac{\delta}{\delta-1}} \int_0^{t*} t^{\frac{-\delta}{\delta-1}}.dt = \alpha.\left(\frac{-1}{\alpha\delta}\right)^{\frac{\delta}{\delta-1}} (1-\delta)\, t^{\frac{-\delta}{\delta-1}} \begin{cases} t* \\ 0 \end{cases} = \left(\frac{\delta-1}{\delta}\right).(-\alpha.\delta.t*)^{-1/_{\delta-1}}$$

The conditions for SRMC to be efficient are strong. It shows that talk about SRMC being real when a particular price is established needs thorough verification.

Without being exhaustive, a major challenge for the electricity pricing question is the sudden shift in an important factor price uprooting the optimality of the production parks. This is observed in Summer 2022, when the gas price increased multifold. Another challenge for the incumbent view on electricity generation and pricing (presented here above) is the shift towards electricity generation from harvested light, wind and water currents. Such natural currents are not available on command by system operators. Nature offers the currents along its laws, but for free (fuel cost is zero). The technologies for harvesting deliver the cheapest kWh ever in history, and with minor external costs. Technological progress is still advancing bringing expenditures further down (IRENA 2022).

Figure B.1: Least-cost Capital-Energy Technologies compose electricity generation systems optimally, equating Long-run and Short-run costs



Production ISOQUANT, continuum of Energy-Capital combinations for generating electricity

Load Duration curve. Meeting 1kW load extra during t* hours: by new capacity (blue) or by longer running of existing capacities (brown)

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