The Economics of Electricity Dynamic Pricing and Demand Response Programmes

Application to Controlling BEVs and PHEVs Charging and Storage

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Abstract

This document is the first deliverable of the project entitled Adaptive and TOU pricing schemes for smart technology integration, funded by the Swiss Federal Office of Energy (SFOE). Its aim is twofold: (i) through an economic analysis, we explore the different possible schemes of adaptive and time-varying tariffs that could be proposed by electricity distributors, in the context of a development of smart-grid technologies; (ii) based on economic models, we evaluate the potential for these tariffs to realise load shifting and/or shedding and to facilitate the integration of battery and plug-in hybrid electric vehicles (BEVs and PHEVs).

Please note that equations with free indices are understood to be valid for all values the indices can take, unless otherwise stated.
Contents

1 Introduction and Motivation .......................................................... 6

2 Types of Rates and Pricing Schemes .............................................. 7

  2.1 Marginal Cost Pricing and Time-Varying Tariffs .......................... 8
  2.2 The Electricity Price Composition in Switzerland ......................... 10
  2.3 The Two Main Origins of Price Variation .................................... 12
  2.4 A Survey of Time-Varying Tariffs ............................................. 14
    2.4.1 Time of Use ................................................................. 15
    2.4.2 Critical Peak Pricing .................................................... 15
    2.4.3 Peak Time Rebates ...................................................... 16
    2.4.4 Real-Time Pricing ...................................................... 16
  2.5 Time-Varying Tariffs for Captive Consumers in Switzerland ............ 17
    2.5.1 Groupe-E - "1to1 energy easy" ....................................... 18
    2.5.2 Romande-Energie - "volta double" .................................... 18
    2.5.3 SIG - "Tarif Profile Double" ........................................... 18
  2.6 Time-Varying Tariffs for Consumers Granted with Network Access in Switzerland ................................................................. 19
    2.6.1 SIG - "Tarif 3/5 périodes" .............................................. 19
    2.6.2 The FlexLast project ...................................................... 20
  2.7 Smart Grids and Time-Differentiated Pricing Schemes ..................... 20

3 Customers’ Response to Time-Differentiated Tariffs and its Econometric Modelling .......................................................... 22
3.1 Effectiveness of Time-Varying Tariffs ........................................... 22
   3.1.1 Ability to Reflect the Market’s Status .................................... 22
   3.1.2 Technology as an Enhancer .................................................. 23
   3.1.3 Barriers to the Diffusion of Innovations ................................. 23
   3.1.4 Rebound and Backfire Effects .............................................. 24

3.2 Overview of Households’ Response to TOU Schemes ..................... 24
   3.2.1 Empirical Evidence in Switzerland ....................................... 24
   3.2.2 Peak-Load Reduction Evidence .......................................... 26

4 Economics of Time-Varying Rates and Load Shifting ........................ 26
   4.1 A Global Model of TOU Pricing .............................................. 27
      4.1.1 Supply Side .................................................................... 27
      4.1.2 Demand Side .................................................................. 29
      4.1.3 Representing the Supply-Demand Equilibrium ...................... 30
      4.1.4 A Numerical Illustration .................................................. 30
   4.2 Non-Cooperative Game Models ................................................ 32
   4.3 Competitive Equilibrium Models ............................................. 34
      4.3.1 A Global Linear Programming Formulation ......................... 34
   4.4 Multilayer Game Models ......................................................... 36

5 Optimal Distributed Charging and Storage Control for a Population of Electric Vehicles .......................... 36
   5.1 Decentralised Control and Incentive-Based Coordinated Charging Control .................................................................................................................. 37
      5.1.1 A Mean-Field Game Solution .............................................. 37
5.1.2 A Decentralised Control Scheme Based on RT Pricing 38

5.2 Optimal Storage and V2B Operations 40

5.2.1 Example of V2B Operations 40

5.2.2 Economic Analysis of the Use of Storage Provided by Idle PHEVs Based on Locational Marginal Pricing 41

5.3 Other Ancillary Services Provided by EVs 42

6 Conclusion 42
1 Introduction and Motivation

Adaptive and dynamic tariffs are designed in such a way to better inform the customer of the status of the electricity market, whose volatility may increase in situations in which the production of electricity from renewable sources substantially penetrates. Indeed, the generation of electricity from solar and wind origin are intrinsically intermittent, leading to potentially large and rapid variations of the marginal price of electricity. Due to the introduction of bidirectional communication possibilities via smart metering systems, it is expected that customers will try to optimise the timing of their different usages in order to benefit from off-peak tariffs, i.e. periods during which the price of electricity is low due to a low demand and a high level of potential production from renewables.

Given the time-scales on which the production of electricity from renewables may vary, adapting ones consumption would represent quite a burden. Automatic solutions integrating decision algorithms already exist on the market. Through the use of smart meters - which are sophisticated electricity meters whose communications are bidirectional and in real-time, connecting the decentralised production and consumption units to the grid - the energy distributors may influence and adapt the demand and adjust it to the production by shifting some of the deferrable loads customers did previously define.

This represents a dramatic shift in the electricity distribution paradigm. Before the appearance and potentially large penetration of intermittent energy sources, the production-side was given the role to be the one that adapts itself to the demand-side. Nowadays, the reverse mechanism, known under the name of demand-response, is about to become prevalent. However, the adoption of demand-response mechanisms by consumers is not straightforward an issue. Indeed, in order for such strategies to be implemented, customers have to accept to give up a certain amount of control on their consumption behaviour in favour of their electricity distributor.

In a context of high penetration of renewables another important issue concerns short term electricity storage to alleviate the intermittent production patterns of these technologies. There is also an opportunity of storing the energy when available at a low cost, i.e. when renewables are the marginal producers, and to inject it back in the electricity network at peak periods. Both aspects of load shifting and possibility of temporary storage are present in the management of a large fleet of BEVs and PHEV\(^1\). Modern electric vehicles’ batteries have large enough a capacity to serve not only as a reserve for the car itself but also as a buffer capable of absorbing the irregularities of the production patterns. Adaptive dynamic pricing scheme will be among the tools used to implement incitative schemes to control distributed charging and storage operations. But, again, customers will have to accept that their vehicles’

\(^1\)BEV: Battery electric vehicle; PHEV: Plug-in hybrid electric vehicle.
batteries are at least partially remotely managed by their electricity distributor in order for such mechanisms to be successfully implemented.

Some surveys have already been made concerning public acceptance and response to dynamic pricing. Most of them concern time of use pricing, which is the less adaptive form of such tariffs. A need exists to complement the few existing surveys concerning acceptability of dynamic pricing schemes, mostly conducted in the United States of America (see e.g. [1]), by regional surveys where conjoint analysis (see e.g. [2, 3, 4]) is used to elicit the acceptability and potential effectiveness of demand-response mechanisms.

A Brief Introduction to Conjoint Analysis

Conjoint analysis is a marketing technique whose target is to measure preferences structure in the presence of a large number of attributes, which appeared in the early 1970s.

Instead of asking consumers to evaluate on a given scale the attractiveness of a scenario or of a product that is characterised by a set of attributes, one offers them to choose among a selection of balanced scenarios. By using simple mathematical techniques, one can extract the relative importance of the attributes. One can then compute the attractiveness of scenarios which were not proposed to the test-panel. Such a knowledge would then allow for an adaptation of the product so as to enhance its desirability.

The rest of the report is organised as follows: Section 2 concerns the different types of time-varying and adaptive tariffs that have been envisioned in utility management with a particular focus on the current practice in Switzerland; Section 3 deals with the modelling of customer response to dynamic tariffs using econometric analyses; Section 4 is devoted to the microeconomics of time varying tariffs for electricity and its representation in planning models; in Section 5 the activities of optimal distributed charging and storage control for a population of electric vehicles are considered; finally, Section 6 provides a conclusion.

2 Types of Rates and Pricing Schemes

This section consists of an inventory and a characterisation of the various time-varying electricity pricing schemes that are available to electricity distributors. Such schemes are designed with the purpose of influencing the final users’ consumption behaviour, the
main target for distributors being to reduce the peak load and to ensure that production
and demand meet, which is especially challenging when renewables take an important
place in the energy panorama.

Many different sorts of time-varying tariffs do exist, the difference between them
being the characteristic time-scales on which they vary and their dynamics. In the
following, we will introduce the main categories of tariffs, ranging from time-of-use
tariffs (TOU) to real-time pricing (RTP). The main advantage of these tariffs is that
they allow the electricity distributors to reflect the state of the electricity generation
facilities, and thus of the marginal cost of electricity, on the prices paid by customers.

The section begins with a brief description of the main arguments for time-varying
tariffs in the electricity sector and continues with a discussion of the main components of
the price of electricity. Finally the main categories of time-varying tariffs are considered,
with particular reference to the case of Switzerland, when available.

2.1 Marginal Cost Pricing and Time-Varying Tariffs

Before starting the survey of dynamical tariffs, let us briefly discuss the economic
reason for the emergence of time-varying tariffs for final consumers. It is well known
that electricity cannot be stored\(^2\), the amount of electricity generated is therefore to be
strongly correlated to the demand level. This results in more electricity being generated
during peak periods (around midday in Switzerland) and less during the night. In off-
peak periods, only those facilities that are characterised by low operation costs are
used (mostly hydro-electric and nuclear facilities in Switzerland). When the demand
grows, the production adapts itself and facilities whose variable costs are higher and
higher begin to be used. The cost of electricity is thereby rising. This shows the
importance of the concept of marginal cost of electricity, which is the cost of producing
one supplementary unit of electricity (a kWh per example). On the wholesale market,
which is competitive, the electricity is naturally priced according to the marginal cost
of its production. Figure\(^1\) shows the fluctuations of the Swiss spot market price across
the day on the 5\(^{th}\) of March 2013\(^3\).

However, in order for consumers and the economy not to be bothered with starting
consuming only when prices are below a certain threshold, electricity distributors (who
produce and buy/sell electricity on the spot market) traditionally apply flat tariffs on
the retail market. These tariffs allow the final consumers to plan their consumption
regardless of the state of the electricity market. Static rates thus imply predictability,

\(^2\)Note, however, that electric power may be used to produce energy that can be stored in batteries,
dams, spinning flywheels, etc. and released at later times.
\(^3\)Retrieved from \url{http://www.epexspot.com/en/market-data/auction/chart/auction-chart/2013-03-05/CH}
Figure 1: Electricity price evolution on the Swiss spot market on March 5th, 2013.

which is an advantage for a prosperous economic development to take place.

However, as already stated in the Introduction, the situation is likely to change because of the following two facts:

1. An important penetration of renewables suggests that the demand has to at least partially adapt itself to production since the latter is subject to rigid short-term capacity constraints. In order to shift some of the demand usages, the electricity price will have to act as a lever.

2. In the last decades the electricity consumption hasn’t stopped rising. Even though the overall efficiency of most devices is improving, the upward consumption trend is not showing any signs of slowing down, as shown in Figure 2. Therefore, the stress in the electricity transmission and distribution infrastructure is likely to worsen in the next years. In order to reduce the need for an early infrastructure upgrade and to improve the network’s reliability, and since the network is dimensioned in order to be able to handle peak loads, time-varying prices would represent an incentive to shift some of the usages out of peak periods.

In summary, whereas the wholesale market prices truly reflect the state of the generation, transport and distribution of electricity, the retail market is at best only partially reflecting the marginal costs of electricity. Economists have long been arguing that time-differentiated pricing schemes have to be enforced in order to provide end-users with incentives convincing them to modify their consumption pattern. It is then concluded that marginal pricing schemes contribute to solving the challenges that have to be addressed by electricity distributors, i.e. lessening the peak load by shifting

some of the loads to off-peak periods and managing the demand so that it adapts to the production. The second point is particularly relevant in situations in which renewables substantially penetrate. In order to be able to qualitatively and quantitatively estimate the effects of time-varying tariffs, it is important to understand the structure of the electricity price. In the following subsection we describe the various components of the price for a kWh of electricity in Switzerland.

2.2 The Electricity Price Composition in Switzerland

In Switzerland, as in most of the western countries, the electricity market is being liberalised. Before the liberalisation, consumers were obliged to buy their electricity to their local distributor, meaning that the latter was charging them with a single price that comprised both the price of energy generation and that of transport and distribution.

As of January 1st 2009, entities consuming more than 100 MWh of electricity per year are granted the network access\(^5\). Consequently these consumers are allowed to use their local electricity distributor’s network to buy electricity on the market, may it be inside or outside Switzerland, and use the local infrastructure to deliver it. Under such a scheme, the structure of the traditional electricity distributor is split in two: one entity being responsible for the electricity generation, import and export, the other one for the electricity delivery to the final users\(^6\). Consequently the price of a delivered kWh

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\(^5\)See SR 734.71, Article 11. Available at [http://www.admin.ch/ch/d/sr/73.html](http://www.admin.ch/ch/d/sr/73.html)

\(^6\)Electricity distributors have the legal obligation to split their activities into these two distinct
has several components, the two most important ones being the price for generating the electricity and the price for its delivery.

Even though only large consumers\[^{7}\] have access to the network, and in anticipation of the complete market liberalisation that should occur in the next years in Switzerland, the bills of all consumers do exhibit the aforementioned structure. More precisely, the price of a kWh is subdivided into the following components:

1. **Electricity generation cost**
   This component corresponds to the cost of producing one kWh of electricity. It may depend on the type of generation facility, on the price of the primary energy that is used, on the facility’s amortisation rate, etc.

2. **Electricity transmission and distribution costs**
   This part of the price is related to the network use necessary to carry the electricity from its generating facility to the final user. It is typically further split in two sub-components corresponding to high voltage networks (transmission, import and export) and low voltage networks (distribution). In Switzerland, the transmission is operated by Swissgrid\[^{8}\] whereas local distributors are responsible for the final transit to the consumer, i.e. a natural monopoly characterises this price component, which is regulated by the ElCom\[^{9}\].

3. **Public fees and services to collectivities**
   The third component is related to the price paid to public collectivities for the use of their assets related to the distribution of electricity. For example, a tax for using public areas for the distribution of electricity is to be incorporated in this component, to the contrary of a tax corresponding to the use of water by hydroelectric facilities, which is to be incorporated in the electricity generation price\[^{10}\]. Local authorities may also use taxes to promote renewables. For example, in the Canton of Vaud, 0.18 cts/kWh are charged to encourage local initiatives in the sector of renewable energy sources (see LVLEne 730.01, Art. 40).

4. **“Feed-in Remuneration at Cost” (KEV) tax**
   In order to encourage the development of energy production from renewable sectors, in a procedure known as *unbundling*, see SR 734.7, Article 10. Available at [http://www.admin.ch/ch/d/sr/73.html](http://www.admin.ch/ch/d/sr/73.html).

\[^{7}\]i.e. more than 100 MWh per year, the end-users consuming less than that amount being said to be *captive*. Note that a Swiss household consumes an average of around 5 MWh of electricity per year (Federal Statistical Office).

\[^{8}\]Swissgrid is the entity operating Switzerland’s transmission system with responsibility for the operation, security and expansion of the 6'700 kilometre long high-voltage grid (Level 1 grid component, corresponding to voltages in the 220 to 380kV range).

\[^{9}\]The ElCom is Switzerland’s independent regulatory authority in the electricity sector. It is responsible for monitoring compliance with the Swiss Federal Electricity Act and the Swiss Federal Energy Act.

ergy sources, Switzerland has decided to guarantee producers that the electricity they generate from renewables will be remunerated at a price that corresponds to their production costs, which may be higher than the market price; the difference being paid through the “Feed-in Remuneration at Cost” Tax (known in Switzerland as the KEV Tax), which is currently fixed at the level of 0.35 cts/kWh. Another surcharge of 0.10 cts/kWh is currently being levied to finance water conservation measures.\(^{11}\)

The relative importance of these components is illustrated on Figure 3 for the years 2009-2014\(^ {12}\).

Figure 3: Composition of the Swiss electricity prices in cts/kWh, VAT excluded. The RPC component corresponds to the “Feed-in Remuneration at Cost” tax.

2.3 The Two Main Origins of Price Variation

In dynamic pricing schemes, both the electricity generation price and the transmission and distribution costs may vary. Periods of high demand would consequently be charged at higher a price. Two mechanisms are responsible for this phenomenon:

1. **Marginal cost of production**

\(^{11}\)For both these two taxes, see [http://swissgrid.ch/swissgrid/de/home/experts/topics/grid_usage.html](http://swissgrid.ch/swissgrid/de/home/experts/topics/grid_usage.html)

\(^{12}\)Illustration valid for the H4 Profile, corresponding to households with a yearly consumption of 4.5 MWh of electricity. (Source: ElCom, Tätigkeitsbericht 2011)
As the demand rises, the set of facilities to be switched on evolves. In periods of low demand, the only facilities running are those which are leading to cheap prices and those that cannot be easily be stopped, e.g. nuclear power plants. When the demand goes up, gas and coal fired power plants are progressively turned on, leading to higher prices. The order in which the power plants are switched on is related to their marginal cost of production, i.e. the cost for producing one more unit of energy, and to the price on the market. The only exceptions to this rule are those facilities that need to run close to full-time for technical reasons.

The corresponding amount charged to consumers is in most cases proportional to the quantity of delivered electricity (measured e.g. in kWh).

2. Transmission and distribution costs

On the other hand, as the demand rises, more electricity is to be conveyed by the transmission and distribution networks. Since the network capacity is finite, the price for electricity transit will tend to rise during periods of high demand (corresponding to large power flows).

The amount charged to consumers resulting from the transmission and distribution costs may have two components: the first one being proportional to the quantity of delivered energy (in e.g. kWh) while the second is proportional to the maximal power\(^{13}\) (in e.g. kW) used in a given period of time. The transmission and distribution costs not only depend on the consumption profile, but also on the topography and on the density of residential development. Note, however, that in the following tariffs the transmission and distribution costs that are charged to final consumers are independent of time, congestion and distance. The only time-varying tariffs are the ones of cross-border flows, the capacity of the latter being allocated by an auction process\(^{14}\).

We thus conclude that, in order to reflect the situation of both the generation facilities and of the transmission and distribution networks, time-varying tariffs are appealing since they allow sending the right price signal to end-users [5]. Indeed, it is for example known that California’s 2000 electricity crisis was caused by rates that were not reflecting the real situation of the electricity market (the wholesale price went up from around 30$ per MWh to 400$ per MWh, without any consequence on the retail prices paid by the final users, see e.g. [6]), leading to blackouts.

Time-varying tariffs also allow a reward for the efforts done in reducing the energy consumption during peak-periods. Indeed, since the price is higher during high demand periods, not consuming a unit of energy can result in potentially high savings.

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\(^{13}\)The maximal power is generally defined as follows. First, the day is split in 15 minutes blocks, then the average power for each of the blocks is computed. The maximum power is then defined as the maximum of these averaged powers.

\(^{14}\)Since April 2011 the Auction Office CASC.EU performs these auctions, see \texttt{http://www.casc.eu/en/Resource-center/CWE--CSE-and-Switzerland}
Many economists have observed that the principle of time-varying tariffs would solve the problems induced by a varying production, may that variation be due to speculation as was the case in California or to intrinsic volatility as is the case for both photovoltaic panels and wind turbines production; see e.g. [5] and references therein. The theoretical appeal of such a solution is thus firmly established. In order to assess the viability of such a strategy, one has to measure the behavioural changes when one is confronted to time-varying tariffs. More precisely, one has to measure the relative change in demand when a user is facing a change in price. This precisely meets the definition of the price-elasticity of the demand, denoted as $\eta$:

$$\eta = \frac{\Delta D}{D} = \frac{\Delta \log (D/D_0)}{\Delta \log (p/p_0)} \quad i.e. \quad D \propto p^\eta$$

(1)

Since the demand is not only sensitive to the price in the same period, but also to the price during other periods (the knowledge of a lower price in the future may tend to lessen the present demand), the corresponding elasticities must be introduced to account for this phenomenon. One can then write, in a self-explanatory notation:

$$D(t) \propto [p(t)]^{\eta_1} [p(t_i \neq t)]^{\eta_p} [D(t_i \neq t)]^{\eta_D}$$

(2)

where the $\eta$s are the elasticities. Note that in most of the models we will consider, the elasticities will be assumed to be constant. The $\eta$s are then determined by fitting the demand. Qualitatively we can already anticipate that $\eta_1$ will in most cases be negative, since the usual response to rising prices is a diminution of the demand. On the other hand, the $\eta_p$ will generally tend to be positive since if the past and/or future price increases, the consumption will tend to be shifted to the current period of time.

Several studies have been carried out in order to determine the effectiveness of time-varying tariffs and to evaluate the price-elasticity. Before exposing the results in Section 3, the existing types of time-varying tariffs are introduced in the next section.

### 2.4 A Survey of Time-Varying Tariffs

Over the years, a number of different strategies have been devised in order for the electricity prices to reflect the state of electricity generation and network congestion. Some of the pricing schemes are characterised by pre-determined adjustments, others by special hours or days when the electricity is charged at a different price, and others truly reflect the changes in the marginal costs. A more refined description of the most widely used tariffs is to be found in the following.
2.4.1 Time of Use

The Time of Use (TOU) tariffs are the simplest and the most extensively used time-varying tariffs. The days are typically split in 2 to 5 periods, each being characterised by a static price. The splitting and prices are pre-determined and typically adapted on a monthly basis. The distributor fixes the electricity prices by using consumption estimates. The aim of TOU tariffs is to partially reflect the situation of the electricity market but has the advantage of being non-dynamical, thereby allowing households and industries to schedule their activities as a function of the TOU blocks.

2.4.2 Critical Peak Pricing

In Critical Peak Pricing (CPP), a normal tariff, which is generally belonging to the TOU family, is valid for most of the days of the year. However, a small number of days per year are subject to a price change. These occurrences correspond to periods of very high demand (peak loads) during which the generating utilities could not provide sufficient a quantity of electricity if keeping the prices flat. The electricity prices during the peak prices may be pre-determined or in some cases reflect the real-time status of the market. These two situations are referred as CPP-F (fixed) and CPP-V (variable).

As far as the authors know, CPP tariffs are not available to Swiss customers. One of the most well known examples of such tariffs is to be found in France. The “Tempo” tariff consists of three TOU tariffs. In order of increasing tariffs, these are: the “blue” one that is valid for 300 days per year, the “white” one for 43 days and the “red” one for the remaining 22 days; see Figure 4. Every day, the colour of the following day is communicated by SMS and email. A set of rules prevents the distributor from using too many highly priced days in a row. The tariffs range is quite wide; the peak period of a “red” day being charged around 7 times more than an off-peak period of a “blue” day.\(^\text{15}\)

A variant of CPP is called interruptible rates. The rates are following the TOU scheme most of the time, but when facing critical events and potential shortages, the facility may call its customers upon to cease their consumption. In the case the customers cannot stop their processes, the electricity is still delivered but at rates that are increased up to several dozens times, see e.g. \([7]\).

\(^{15}\)See [http://particuliers.edf.com/gestion-de-mon-contrat/options-tempo-et-ejp/option-tempo/details-de-l-option-52429.html](http://particuliers.edf.com/gestion-de-mon-contrat/options-tempo-et-ejp/option-tempo/details-de-l-option-52429.html)
2.4.3 Peak Time Rebates

The Peak Time Rebates (PTR) scheme is very similar to CPP in that only a reduced number of periods, characterised by either a high demand or a low production, are impacted by exceptional tariffs. In PTR, the incentive not to consume during peak time is not realised by increasing the corresponding prices, but in a non-punitive way by rewarding consumers if they agree to reduce their loads (compared to their baseline consumption) by either shedding them or shifting them outside of the critical peak periods. Note that no penalty is inflicted if consumers use electricity during these special periods, the usual tariff being applied. Figure 5 illustrates the effect of offering rebates by comparing the effective consumption to the averaged baseline consumption. Note that outside the peak period, the consumption of the group being offered with interruptible rates is higher than the baseline consumption. This is an illustration of the rebound effect, which will be discussed in 3.1.4.

2.4.4 Real-Time Pricing

In Real-Time Pricing (RTP) schemes, electricity tariffs are reflecting the electricity market situation. Prices are not pre-determined and are typically subject to hourly changes. This pricing scheme being extremely difficult to handle (intensive exchange of data, new billing procedures to define, etc.), it is often proposed in conjunction with other contracts. For example, a fixed quantity of energy (the so-called customer baseline load) may be sold at TOU rates, the amounts exceeding the threshold being the only ones charged according to the RTP scheme. Such a hedging strategy reduces the customer’s exposition to price volatility and offers utilities a greater revenue stability. Financial risk management products are also offered by some utilities in order for customers to customise their exposure to price differences, e.g. by entering forward contracts. Examples of voluntary RTP schemes in the United States of America and their effects on load shifting may be found e.g. in [1].
Figure 5: The blue line corresponds to the control group, which is charged with flat tariffs. The magenta line corresponds to consumers being offered with PTR, but not responding to the incentives. Finally the black line corresponds to the consumers responding to the PTR incentives [8]. The period during which rebates were offered is the one ranging from 11am to 6pm.

2.5 Time-Varying Tariffs for Captive Consumers in Switzerland

As anticipated in the beginning of this section, the first step of the liberalisation of the Swiss electricity market was to allow end-users consuming more than 100 MWh of electricity per year to freely choose their electricity producer, they are said to have a network access. The remainder of the end-users are said to be captive since, for them, the electricity market takes the form of a monopoly. The tariffs available for captive consumers are regulated according to SR 734.7 Article 6 and SR 734.71 Article 4. The liberalisation process will eventually allow every end-user to benefit from the network access.

In addition to the traditional flat rates, Switzerland’s main distributors propose TOU schemes. These tariffs are available both for captive consumers and for consumers that benefit from the network access. In Switzerland, the only non-flat tariffs offered to captive consumers known to the authors are of the TOU kind. Examples of such tariffs are given in the following.

\[\text{http://www.strompreis.elcom.admin.ch/}\]

\[\text{http://www.admin.ch/ch/d/sr/73.html}\]
2.5.1 Groupe-E - "1to1 energy easy"

In the “1to1 energy easy”, the day is split in three periods, the one ranging from 7am to 21pm being the peak period during which the electricity is around 1.5 times more expensive than in the off-peak period (19.38 vs 12.54 cts/kWh). For clients that are consuming more energy, but are still captive, the electricity price is lower but is to be supplemented with a power component of a few CHF per kW. In this case, i.e. in the “1to1 energy easy power” pricing scheme, the kW is billed at CHF 6.80, while the on-peak and off-peak tariffs are respectively reduced to 15.08 and 8.74 cts/kWh. Note that the power is defined as the maximal averaged power on 15 minutes blocks during the month at hand.

Figure 6: Groupe-E - "1to1 energy easy"

2.5.2 Romande-Energie - "volta double"

Romande Energie’s “volta double” tariff is very similar to the previous scheme we have discussed. The prices are pre-determined at 21.89 cts/kWh during the peak period and 13.34 cts/kWh during the rest of the day and during weekends.

Figure 7: Romande-Energie - "volta double"

2.5.3 SIG - "Tarif Profile Double"

In SIG’s “Tarif Profile Double”, the same kind of tariffs apply. Depending on the proportion of renewables the current incorporates, the peak periods are billed from 22.10 cts/kWh to 27.82 cts/kWh while the off-peak ones range from 20.46 cts/kWh to 27.82 cts/kWh.
2.6 Time-Varying Tariffs for Consumers Granted with Network Access in Switzerland

In Switzerland, end-users who annually consume more than 100 MWh of electricity are granted the right to access the network. Thereby they are allowed to buy their electricity on the market, in or outside Switzerland. As a second step of the Swiss electricity market liberalisation process, all consumers will eventually have the right to access the market and will not be bound anymore to buy their electricity from their local distributor. The procedure, which is described in SR 734.7, Article 34, is planned to take place five years after the law has been enforced and may be challenged by referendum.

In the following, we give two examples of possibilities that are available for customers that have access to the network, even though the prices for large companies remain largely unknown for understandable reasons. An in-depth evaluation of the effect of time-differentiated tariffs for large consumers may be found in [9].

2.6.1 SIG - "Tarif 3/5 périodes"

In SIG’s tariffs for large consumers – also available for captive clients consuming between 30 and 100 MWh of electricity per year – the days are subdivided in 3 or 5 periods as indicated by Figure 9. Each period is characterised by its own energy (e.g. in kWh) and power (e.g. in kW) prices.

19 Customers who buy their electricity abroad have to purchase the corresponding cross-border capacity, for which auctions are organised.

20 Available at [http://www.admin.ch/ch/d/sr/73.html](http://www.admin.ch/ch/d/sr/73.html)
From this example, one can see that tariffs designed for large consumers are not very different from those captive consumers are charged with. However, very large consumers are known to regroup in order to emit calls for bids and thereby to be offered competitive contracts together with negotiation possibilities.

### 2.6.2 The FlexLast project

The FlexLast project illustrates the innovative mechanisms available to large electricity consumers. Originating from a collaboration among Migros, BKW, Swissgrid and IBM, the FlexLast project aims at using a giant 200,000-m²-sized refrigerator as a buffer to cope with the intermittent character of the electricity generated from renewable sources and that is injected in the grid. The warehouse, which consumes 6 GWh of electricity per year, is equipped with an algorithm taking into account the grid status, the status (activity, temperature, etc.) of the refrigerator, the production of renewables, etc. and controlling the cooling strategy of the building.

The lesson emerging from this example is that it is indeed possible to modify one’s consumption pattern so as to dynamically absorb the variability that is inherent to the electricity production from wind and solar technologies. Since such a strategy strongly relies on real-time data, communication technologies and automation are crucial ingredients, which are the subject of the next subsection.

### 2.7 Smart Grids and Time-Differentiated Pricing Schemes

Under the Smart Grid paradigm, the electricity distribution network is supplemented with bidirectional real-time communication capacities. The latter aptitude may then be exploited to transmit close to real-time price signals. As anticipated in the aforementioned FlexLast project, the problems emerging due to the variability of both sun- and wind-powered electricity generation may find their solutions in a real-time partial adaptation of the consumption to the production. In order to exploit the load shifting potential of households and industry, market incentives should be properly designed so as to stimulate a sizeable response from end-users (demand-response mechanisms).

Implementing such a vision requires the installation of decentralised energy management systems that dynamically adapt the consumption behaviour of the home or business by exchanging data with the grid, e.g. short-term prices, storage capacities, comfort requirements, occupancy pattern, etc. Both the demand- and the production-side would benefit from dynamical pricing:

\[ \text{See e.g. } \text{http://www.swisselectricity.com}
\]
\[ \text{http://www.bkw-fmb.ch/bkwfmb/fr/home/klimafreundliche_stromproduktion/tatbeweise/energieeffizienz/smartgrid-pilotprojekt.html} \]
1. **Demand-side**
   Since Smart Grid schemes are dynamic, the demand level is automatically adapted so as to optimise the usage, storing and selling of electricity while maintaining comfort above a pre-defined threshold. Robust strategies incorporating algorithms that can face the uncertainties regarding future prices and conditions are deployed in such situations. The consumption is thereby occurring during periods characterised by low prices, resulting in the satisfaction of the end-users’ needs together with a lowering of their bills.

2. **Production-side**
   On the production side, Smart Grid schemes not only allow for an optimisation of the way energy from renewables is used, but also represent a solution to the problem of stability that occurs as soon as renewables substantially penetrate. The Smart Grid concept indeed provides the framework (at both the physical and algorithmic levels) enabling the energy emerging from renewable sources to offer regulation services despite their intrinsic variability. Issues regarding the combined effect of multiple users using different parametrisations may be solved thanks to the IT capacities brought by Smart Grids.

For both the demand and production sides, the question of the control of a certain number of domestic appliances by the local distributor is raised. The following two options are available:

1. **Automatic control**
   A certain subset of the processes would be dynamically controlled by a local computer, according to pre-defined criteria among which the price of electricity.

2. **Remote control**
   The remainder of the devices of which certain loads may be deferred would be controlled by the distributor, according to pre-defined criteria. The distributor would then be in charge of delivering and storing the electricity whenever suits the grid best.

Remotely controlled devices (including local storage capacities) would open the possibility for grid operators to dynamically manage the grid status by adjusting the demand. A critical issue for the success of the Smart Grid concept is thus the degree of acceptance by end-users. This is the subject of Section [3](#).
3 Customers’ Response to Time-Differentiated Tariffs and its Econometric Modelling

This section is devoted to the main factors that influence the end-users’ acceptance of time-differentiated tariffs and, more generally, of the Smart Grid paradigm. Experimental studies evaluating the price elasticity in the Swiss context and the peak-load reduction at the international level are then presented.

3.1 Effectiveness of Time-Varying Tariffs

3.1.1 Ability to Reflect the Market’s Status

The efficiency of time-varying pricing schemes may be evaluated from various perspectives. From the distributor’s point of view, one of the criteria that applies is the ability to reflect the market situation in order for its consumers to dynamically adapt their behaviours to the present context. Among the pricing schemes that have been presented (TOU, CPP-F, CPP-V, PTR, RTP), RTP pricing schemes are the ones that are the most likely to generate a change in the end-users’ response whose effects on the electricity market are beneficial, according to [10]. Indeed, since the rate of tariff adaptation in RTP schemes generally is occurring once every hour, the image the customers can build of the electricity market is quite accurate.

On the other hand, TOU’s ability to capture the state of the electricity market is limited since the time-blocks and the corresponding prices are generally kept fixed for several months in a row. As an illustration, the author of [10] evaluates that a TOU scheme would only have reflected around 15 to 20% of the price variation that has occurred in the wholesale market during the California crisis of 2000-2001.

Since TOU is only partially representing the real-time situation of the electricity market, it is often proposed in conjunction with load charges, i.e. not only is the energy charged, but the peak power too. Load charges represent a convenient way of charging the end-users with a tariff that partially reflects their power usage pattern. However, since load charges are only related to the peak usage, they do not prevent end-users to concentrate their usage around the peak period.

Moreover, RTP prices are typically announced with a delay of less than a day, they are thereby capable of reflecting unplanned events.
3.1.2 Technology as an Enhancer

Even if energy behaviours may have an impact on energy savings (see e.g. [11] for a review), one of the most important factors that influence the effectiveness of time-varying tariffs, measured e.g. by the reduction in the peak-load, is the one of enabling technologies. Indeed, on average, the end-users’ enthusiasm to dynamically adapt their behaviour to price incentives drops off very quickly, even more in the electricity market due to the low level of prices that are nowadays faced. In order to witness a sustainable effect, enabling technologies are to be provided. These technologies may take forms as simple as smart thermostats provided with algorithms that take into account the average prices during the day, the weather conditions and forecast, the pre-defined comfort zone, etc. The effect of such devices have shown to be more important and more durable, see e.g. [12, 13, 14] and [15] in the case of substantial penetration of energy generation from renewable sources.

3.1.3 Barriers to the Diffusion of Innovations

Even though some innovations would have a positive impact, i.e. they are rationally desirable, they are not perforce adopted. Several obstacles to the adoption of innovations may be identified:

- Too small benefits considering the implementation efforts,
- Lack of knowledge about the existence of alternatives (bounded rationality)
- Emotional bias and/or attraction towards a particular brand,
- Analysis restricted to short-term consequences (see e.g. [16, 17]),
- Group dynamics (peer support or pressure),
- ... 

A comprehensive review of the major obstacles faced by innovations and of successful adoption strategies in the energy sector may be found in [18]. The electricity sector is certainly concerned by all of the obstacles in the above list but the emotional one, which is most probably negligible.

An estimate of the adoption potential can be found by measuring the price, past and future demand elasticities, see equation (2). The next subsection consists in a review of the works performed in the Swiss context, which measure the price elasticities in the Swiss residential sector.
3.1.4 Rebound and Backfire Effects

In the above, efficiency issues have been approached under the angle of peak-load reduction and of the tariff’s ability to reflect the market dynamics. Even though the performance of dynamic pricing schemes, in particular RTP, have been assessed in these domains, it remains largely unclear whether dynamic pricing schemes tend to lessen or not the overall consumption. Unless distributors’ revenues are decoupled from the quantity of electricity sold (see e.g. [19]), their interests are certainly more to be found in shifting loads rather than in shedding them. Figure 5 is a representative example of load shifting. It was moreover noticed in [13] that the dynamical tariffs introduced in California did not result in any consumption reduction:

There was essentially no change in total energy use across the entire year based on average SPP prices. That is, the reduction in energy use during high-price periods was almost exactly offset by increases in energy use during off-peak periods.

As is very often the case when introducing new technologies, an increased efficiency in one domain tends to favourably impact the amount of time and resources that can be devoted to other activities. Progress realised in the electricity sector may then be compensated by other highly carbon-emitting activities. The owner of an electric car may for example feel more comfortable with the idea of flying more often, thereby partially annihilating his efforts when viewed from an holistic perspective. For a discussion of this effect, known as the rebound effect, and of situations in which the overall effect is negative (backfire effect), see e.g. [20].

3.2 Overview of Households’ Response to TOU Schemes

3.2.1 Empirical Evidence in Switzerland

Estimating the elasticity of the Swiss households’ electricity demand is a complex task. To tackle this challenge, the author of [21] has collected data from several Swiss electricity distributors proposing two-period TOU tariffs. Assuming that the demand takes the form

\[
\begin{align*}
D_i^{on}(t) & \propto \left[ p_i^{on}(t) \right]^{\eta_{on}} \cdot \left[ p_i^{off}(t) \right]^{\eta_{off}}, \\
D_i^{off}(t) & \propto \left[ p_i^{on}(t) \right]^{\eta_{on}} \cdot \left[ p_i^{off}(t) \right]^{\eta_{off}},
\end{align*}
\]

where \( i \in \text{cities}, \ t \in \text{years} \).
where the proportionality factors take care of various other influences such as the level of income, the households’ size, the number of heating and cooling days, and where “on” and “off” respectively stand for on- and off-peak, the author found elasticities of the following magnitude:

\[
\begin{array}{c|c|c|c}
\eta_{\text{on}} & \eta_{\text{off}} & \eta_{\text{on}} & \eta_{\text{off}} \\
-0.85 & 1.10 & 0.47 & -0.92 \\
\end{array}
\]

Note that the elasticities defined in (3) are relating the demand and the price evaluated at the same time \(t\), they are therefore known as short-term elasticities. If one were to consider the effect of the prices at time \(t - 1\) on the demand at time \(t\), one would introduce long-term elasticities. In [21], the author finds long-term elasticities that are generically larger in absolute value than the aforementioned short-term ones. This effect is interpreted as being due the fact that if end-users are given more time to adapt to a change of price, not only their behaviour will change, but also the kind of devices they own. By adapting their devices, end-users change their consumption habits by either being able to consume less in the case of an increasing price or by shifting more of their loads more effectively, leading to larger elasticities.

Let us now return to the short-term elasticities. As anticipated in subsection 2.3, the own-price elasticities are negative and cross-prices elasticities positive. The rationale behind this is simply that as the price rises during a peak period, end-users tend to consume less during that period (\(\eta_{\text{on}} < 0\)) and shift their consumption towards off-peak periods (\(\eta_{\text{off}} > 0\)). The same happens when the off-peak price rises: the demand during the off-peak period diminishes (\(\eta_{\text{off}} < 0\)) while the on-peak period’s demand augments (\(\eta_{\text{on}} > 0\)). One can thus conclude that on- and off-peak electricity are substitutes.

As can be seen from the numerical values reported in the above table, the substitution is however not symmetric: the sensitivity to a off-peak price rise is greater than the one to an on-peak price rise (\(\eta_{\text{off}} > \eta_{\text{on}}\)), as illustrated by Figure 10. On the left-hand side, the rise in price lessens the price difference among the two periods, consumers would thus tend to shift some loads towards the on-peak period since it would improve their comfort. On the other hand, even though an on-peak price rise augments the difference among the two periods, any load shifting would result in less comfort. A good estimate of the amount of deferrable loads together with comfort issues are thus absolutely crucial to understand the demand response to a price variation.

Note that the estimation of [21] were realised by using present-day data, i.e. they do not include the effects automation could bring in the case of a Smart Grid deployment.
Figure 10: Cross-demand adaptation to a price increase ($\Delta p$). The size of the arrow indicates the sensitivity of the demand response to $\Delta p$, i.e. that $\eta_{\text{on}}^{\text{off}} > \eta_{\text{off}}^{\text{on}}$.

### 3.2.2 Peak-Load Reduction Evidence

In order to assess the efficiency of the peak-load reduction due to time-varying tariffs, [22] gathered data from 15 experiments, ranging from simple TOU schemes to RTP ones with enabling technology, mostly in the United States of America. The conclusion from this study is that the effect may be substantial, and even more if enabling technologies are present, see Figure 11:

> . . . demand responses vary from modest to substantial, largely depending on the data used in the experiments and the availability of enabling technologies. Across the range of experiments studied, time-of-use rates induce a drop in peak demand that ranges between three to six percent and critical-peak pricing tariffs lead to a drop in peak demand of 13 to 20 percent. When accompanied with enabling technologies, the latter set of tariffs lead to a drop in peak demand in the 27 to 44 percent range.\(^{25}\)

### 4 Economics of Time-Varying Rates and Load Shifting

This section contains a review of the microeconomics that lie behind the design of time-varying rates. In a first subsection the modelling approach proposed in [23] is presented. It consists of a dynamic partial (supply-demand) equilibrium model used to determine the optimal dynamic pricing when the demand responds to price change.

\(^{25}\)Quote from [22]'s conclusion.
Figure 11: Relative reduction of peak load observed in the 15 experiments studied in [22].

with some delay. In a second subsection the more general concept of optimisation with equilibrium constraint is considered. It seems to the authors that this framework is the best adapted to study the design of time-varying or adaptive pricing for electricity or to include these schemes in planning models.

4.1 A Global Model of TOU Pricing

In this section, we present the model elaborated by Çelebi and Fuller in [23]. The supply- and demand-side of the model are successively reported. After the merge of these two parts, an illustration in the Swiss context is performed.

4.1.1 Supply Side

Let us first consider the supply-side. It contains \( m \) facilities (indexed by \( i \)), \( n \) demand or TOU blocks (indexed by \( j \)), the model describes the evolution during \( T \) months (indexed by \( t \)). The discount factor is \( r \).

The model is characterised by the following parameters that may depend on the month \( t \):
Number of hours in demand block $j$ : $H_j(t)$,

Cost per produced MWh by facility $i$ : $c_i(t)$

Capacity in MW of facility $i$ : $K_i(t)$

Energy demand in MWh during the hour $h$ of block $j$ : $d_{jh}(t)$

**Decision Variables**  The decision variables consist of the energy flowing from facility $i$ during the hour $h$ of block $j$ : $z_{ijh}(t)$.

**Supply model**  If the demand was known and fixed, the supplier would solve the following linear program

\[
\text{minimise} \sum_{t=1}^{T} \left( \sum_{i=1}^{m} \sum_{j=1}^{n} \sum_{h=1}^{n} r^t c_i(t) z_{ijh}(t) \right)
\]

subject to the following constraints:

\[
\sum_{i=1}^{m} z_{ijh}(t) \geq d_{jh}(t) \quad (5)
\]

\[
z_{ijh}(t) \leq K_i(t) \quad (6)
\]

\[
z_{ijh}(t) \geq 0 \quad (7)
\]

The quantity between brackets in (4) represents the daily cost during month $t$. Equations (5) to (7) respectively correspond to the requirements that the demand is met (5), the facilities are running below their maximal capacities (6) and that the energy flow is positive (7). The dual variables corresponding to equations (5) and (6) respectively are $p_{jh}(t)$ and $u_{ijh}(t)$, which are greater or equal to zero. The Lagrangian can thus be written as:

\[
\mathcal{L} = \sum_{t=1}^{T} \sum_{i=1}^{m} \sum_{j=1}^{n} \sum_{h=1}^{n} r^t c_i(t) z_{ijh}(t)
\]

\[
+ \sum_{j=1}^{n} H_j(t) \left( \sum_{i=1}^{m} z_{ijh}(t) - d_{jh}(t) \right) \quad (8)
\]

\[
+ \sum_{i=1}^{m} \sum_{j=1}^{n} \sum_{h=1}^{n} u_{ijh}(t) \left( z_{ijh}(t) - K_i(t) \right)
\]

Note that we can interpret $p_{jh}(t)$ as the cost of increasing the demand $d_{jh}(t)$ by one unit (a MWh in the case at hand), while $u_{ijh}(t)$ may be interpreted as the cost of decreasing the capacity $K_i(t)$ by one unit (a MW in the case at hand).
If the demand was known to the distributor, he would solve the above optimisation problem, find the optimal solution $z_{ijh}(t)$ (using e.g. the simplex algorithm) and then produce $z_{ijh}(t)$ MWh during the hour $h$ of block $j$ from facility $i$, and this all days of month $t$.

Let us finally define the $\delta_{jh}(t)$ parameter as:

$$\delta_{jh}(t) \equiv \frac{d_{jh}(t)}{d_j(t)}$$

where

$$d_j(t) \equiv \sum_{h=1}^{H_j(t)} d_{jh}(t)$$

for a later use. It measures the proportion of the demand in block $j$ that takes place during hour $h$.

### 4.1.2 Demand Side

In the above supply model, the demand $d_{jh}(t)$ is considered as known and fixed. However, this assumption should be relaxed and a model of the demand elaborated. Since the response of consumers to changing prices is distributed over time (see e.g. [24]), a geometric distributed lag (GDL) demand law is used by [23]. For a single commodity model with constant elasticities $b$ and $e$, it takes the form:

$$d(t) = a(t)p(t)^b d(t - 1)^e,$$

which in its log form is given by:

$$\ln[d(t)] = \ln[a(t)] + b \ln[p(t)] + e \ln[d(t - 1)].$$

Equation (11) can be extended to the multi-commodity case, the commodities being the electricity demand in the different blocks of the day:

$$\ln[D_j(t)] = A_j(t) + \sum_{k=1}^{n} B_{jk} \ln[P_k(t)] + E_{jj} \ln[D_j(t - 1)],$$

where:

- $A(t)$ Vector representing non-price effects of period $t$,
- $D(t)$ Vector of electricity demand for each block in period $t$,
- $P(t)$ Vector of electricity price for each block in period $t$,
- $B$ Square matrix of own- and cross-price elasticities,
- $E$ Square diagonal matrix of lag elasticities.

The outcome of (12) is the knowledge of the demand for each TOU block, depending on the electricity price of the block, the past demand, the elasticities and on non-price effects.
4.1.3 Representing the Supply-Demand Equilibrium

We now merge the two parts of the problem: the supply (cf. 4.1.1) and demand (cf. 4.1.2) sides. In order to do so, \( d_j(t) \) and \( D_j(t) \) are first identified. The problem is then represented by a mixed complementarity problem (MCP) composed of the complementarity conditions for the optimal supply problem derived from the Lagrangian (8):

\[
\begin{align*}
    z_{ijh}(t) &\geq 0 \quad \perp r^t c_i(t) - p_j(t) + u_{ijh}(t) \geq 0, \\
    p_j(t) &\geq 0 \quad \perp \sum_{i=1}^{m} z_{ijh}(t) - d_j(t) \geq 0, \\
    u_{ijh}(t) &\geq 0 \quad \perp K_i(t) - z_{ijh}(t) \geq 0,
\end{align*}
\]

and of the demand side, where the price \( p_j(t) \) for each of the TOU blocks is derived from the dual variables associated with the discounted marginal cost:

\[
\ln[d_j(t)] = a_j(t) + \sum_{k=1}^{n} b_{jk} \ln[p_k(t)] + e_{jj} \ln[d_j(t-1)],
\]

\[
d_j(t) = \delta_{jh}(t) d_j(t),
\]

\[
p_j(t) = \frac{1}{r^t} \sum_{h=1}^{H_j(t)} \delta_{jh}(t) p_{jh}(t).
\]

4.1.4 A Numerical Illustration

In order to illustrate the aforementioned model, let us apply it to a region roughly the size of Switzerland on a three-months period. The implementation code has been written in GAMS\(^{26}\) and solved using the PATH solver\(^{27}\).

The generation facilities are taken to be:

<table>
<thead>
<tr>
<th>Type</th>
<th>Installed capacity [MW]</th>
<th>Costs [CHF/MWh]</th>
<th>Availability [%]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydro</td>
<td>11400</td>
<td>10</td>
<td>70</td>
</tr>
<tr>
<td>Nuclear</td>
<td>560</td>
<td>76</td>
<td>90</td>
</tr>
<tr>
<td>Renewables</td>
<td>3800 (non hydro)</td>
<td>150</td>
<td>0 - 15</td>
</tr>
<tr>
<td>Imports</td>
<td>10000</td>
<td>200</td>
<td>100</td>
</tr>
</tbody>
</table>

\(^{26}\)General Algebraic Modelling System, see http://www.gams.com

\(^{27}\)PATH solves Mixed Complementarity Problems, see http://pages.cs.wisc.edu/~ferris/path.
where the costs have been extracted from the ETSAP database\textsuperscript{28} and where the last column indicated the averaged availability of the corresponding electricity source during a typical day. The availability for renewables is taken to be varying across the day with solar activity peaking at around 2pm and wind activity around 6pm. Note that a straightforward procedure would enable the model to take exports into account.

The days are subdivided in two periods (\textit{i.e.} demand blocks), which respectively are:

<table>
<thead>
<tr>
<th>Name</th>
<th>Period</th>
<th>Consumption [%]</th>
</tr>
</thead>
<tbody>
<tr>
<td>On-Peak</td>
<td>7 am to 9 pm</td>
<td>72</td>
</tr>
<tr>
<td>Off-Peak</td>
<td>9 pm to 7 am</td>
<td>28</td>
</tr>
</tbody>
</table>

The demand for electricity is taken to be around 240 PJ/year (\textit{i.e.} 66.7 TWh/year). Since the numerical example is only designed to be illustrative, the elasticities used are directly taken from \cite{21}:

\[
\{b_{jk}\} = \begin{pmatrix} -0.8 & 0.8 \\ 0.5 & -0.7 \end{pmatrix} \quad \text{and} \quad e_{jj} = 0.5 \quad \forall j \in \{1, 2\} \tag{19}
\]

\textbf{Results}

The following table summarises the prices in CHF per MWh computed for the on-peak and off-peak blocks by solving the model designed in \cite{23}, which has been refined to take into account the variability of electric production emerging from renewable energy sources:

<table>
<thead>
<tr>
<th></th>
<th>On-Peak</th>
<th>Off-Peak</th>
</tr>
</thead>
<tbody>
<tr>
<td>Month 1</td>
<td>39.1</td>
<td>20.6</td>
</tr>
<tr>
<td>Month 2</td>
<td>46.1</td>
<td>32.4</td>
</tr>
<tr>
<td>Month 3</td>
<td>47.8</td>
<td>33.6</td>
</tr>
</tbody>
</table>

Table 1: Prices $p_j(t)$ [CHF/MWh]

From the last table, one can observe that even though the hydro capacities are sufficient to produce all the electricity for the off-peak period:

\[
\begin{align*}
\text{Off-peak hydro production} & \quad 0.7 \cdot 11.4 \ \text{GW} \cdot 10 \ \text{h/day} \cdot 30 \ \text{day/month} \\
& = 2394 \ \text{GWh/month}, \\
\text{Off-peak demand} & \quad 0.28 \cdot 67.5 \ \text{TWh/year} \cdot 1/12 \ \text{year/month} \\
& = 1575 \ \text{GWh/month},
\end{align*}
\tag{20}
\]

the corresponding prices are higher than the operations' costs per MWh (10CHF/MWh for hydro), the reason being that, thanks to the fact that on-peak and off-peak electricity

\textsuperscript{28}ETSAP is the International Energy Agency’s Energy Technology Systems Analysis Program. Database available at \url{http://www.iea-etsap.org/web/Supply.asp}.
are substitutes as may be seen from [19], an important part of the consumption is shifted towards the off-peak period. The demands are given below in TWh per month:

<table>
<thead>
<tr>
<th></th>
<th>On-Peak</th>
<th>Off-Peak</th>
</tr>
</thead>
<tbody>
<tr>
<td>Month 1</td>
<td>3.05</td>
<td>2.39</td>
</tr>
<tr>
<td>Month 2</td>
<td>3.20</td>
<td>2.39</td>
</tr>
<tr>
<td>Month 3</td>
<td>3.25</td>
<td>2.39</td>
</tr>
</tbody>
</table>

Table 2: Demand $d_j(t)$ [TWh/month]

The off-peak price thus takes into account the fact that the hydro capacities are saturated and that any increase in the demand would either have to be met by using more expensive facilities or by rising the price so as to lower the demand (using the negativity of the $b$ matrix’s diagonal elements).

### 4.2 Non-Cooperative Game Models

In [25] the relationship between a retailer practising real-time pricing and a finite set of customers optimising the timing of their electricity consumption is modelled as a non-cooperative game which admits, under some general conditions a unique and stable Nash equilibrium. The model is summarised below, in a slightly more general formulation than the one used in [25].

**Retailer** The distributor has access to its own production equipment and also to the wholesale market. Depending of the total demand $D(t)$ in a time slot $t$ of the day, the marginal cost of production is given by $\gamma(D(t))$, which is the price that will be charged.

**Consumers** Each consumer $i$ has a minimum daily requirement of electricity $\beta_j^i$ for each type of service $j$. Let $x_j^i(t)$ the demand by consumer $i$ to satisfy service $j$ at time slot $t$. The following constraints must thus be satisfied:

$$\sum_t x_j^i(t) \geq \beta_j^i,$$

(21)

$$x_j^i(t) \geq x_j^i[\text{min}](t)$$

(22)

$$x_j^i(t) \leq x_j^i[\text{max}](t)$$

(23)

where $x_j^i[\text{min}](t)$ and $x_j^i[\text{max}](t)$ are given bounds. The dual variables corresponding to the constraints (21) to (23) respectively are $\eta_j^i$, $\mu_j^i(t)$ and $\nu_j^i(t)$, which are greater or
equal to zero. Let us define the following sets: \( \mathbf{x} = (\mathbf{x}(t))_{t \in T} \), where \( \mathbf{x}(t) = (\mathbf{x}(t))_{i \in I} \), with \( \mathbf{x}(t) = (x^j(t))_{j \in J} \).

**Payoff to consumer** The total demand in time slot \( t \) is given by:

\[
D(t) = \sum_i \sum_j x^j_i(t).
\]  

(24)

This determines the marginal cost \( \gamma(D(t)) \), and hence the tariff payed at time slot \( t \) by each customer. The aim of the \( i \)-th customer is thus to minimise

\[
\psi^i(\mathbf{x}) = \sum_t \gamma(D(t)) \left( \sum_j x^j_i(t) \right),
\]  

(25)

under the constraints (21) to (23). Note that the interdependence among customers comes from the price determination equation, see (24). The Lagrangian for the \( i \)-th consumer can thus be written as:

\[
L^i = \psi^i(\mathbf{x}) + \sum_j \eta^j_i \left( \beta^j_i - \sum_t x^j_i(t) \right) + \sum_{t,j} \mu^j_i(t) \left( x^j_i[\min](t) - x^j_i(t) \right) + \sum_{t,j} \nu^j_i(t) \left( x^j_i(t) - x^j_i[\max](t) \right).
\]  

(26)

The first order conditions for a Nash equilibrium are given by:

\[
0 = \frac{\partial L^i}{\partial x^j_i(t)} = \frac{\partial \psi^i(\mathbf{x})}{\partial x^j_i(t)} - \eta^j_i - \mu^j_i(t) + \nu^j_i(t),
\]  

(27)

which can be written as:

\[
\left( \gamma(D(t)) + \gamma'(D(t)) \left( \sum_k x^k_i(t) \right) \right) - \eta^j_i - \mu^j_i(t) + \nu^j_i(t) = 0,
\]  

(28)

with the following complementarity conditions:

\[
\eta^j_i \geq 0 \quad \text{and} \quad \eta^j_i \left( \sum_t x^j_i(t) - \beta^j_i \right) = 0, \quad \text{(29)}
\]

\[
\mu^j_i(t) \geq 0 \quad \text{and} \quad \mu^j_i(t) \left( x^j_i(t) - x^j_i[\min](t) \right) = 0, \quad \text{(30)}
\]

\[
\nu^j_i(t) \geq 0 \quad \text{and} \quad \nu^j_i(t) \left( x^j_i(t) - x^j_i[\max](t) \right) = 0. \quad \text{(31)}
\]

Applying classical theorems (see e.g. [26]), we can find easily conditions which assure that an equilibrium exists and that it is unique if the \( \gamma(D(t)) \) function is strictly convex and increasing.
4.3 Competitive Equilibrium Models

The model of the previous subsection may be adapted to situation in which there are a consequent number of players. To do so, let us assume that each customer $i$ is replicated $n$ times with demand parameters $\beta^j_i/n$ and bounds $x^j_i[\min(t)/n$ and $x^j_i[\max(t)/n$. This describes a game where the number of players increases while the influence of each player diminishes. The first order conditions for a Nash equilibrium (28) is now given by:

$$\left( \gamma(D(t)) + \gamma'(D(t))\frac{\sum_k x^j_{k}(t)}{n} \right) - \eta^j_{i} + \mu^j_{i}(t) - \nu^j_{i}(t) = 0. \quad (32)$$

When $n \to \infty$ the conditions of a competitive equilibrium are met. Note that for each type of player $i$ and type of service $j$, the following constraint must hold:

$$\sum_t x^j_i(t) - \frac{\beta^j_i}{n} \geq 0, \quad (33)$$

which is the same as (21). The same reasoning applies for the other constraints and, as a consequence, the KKT multipliers are the same as before.

In the large $n$ limit, the term $\gamma'(D(t))\frac{\sum_k x^j_{k}(t)}{n}$ tends to 0, the condition (32) thus becomes:

$$\gamma(D(t)) - \eta^j_{i} - \mu^j_{i}(t) + \nu^j_{i}(t) = 0. \quad (34)$$

Each consumer is now a price taker. His decisions have no influence on the price. The quantities $x^j_i(t)$ are then determined by using (34) together with the complementarity conditions (29)-(31).

In [25] these games are shown to be similar to a class of games defined on transport or communication networks. In [27] the convergence of Nash equilibria to a traffic equilibrium called Wardrop equilibrium was proven along very similar lines to those exposed in this section.

4.3.1 A Global Linear Programming Formulation

The above model only considers the demand side. In order to represent the supply side, the description developed in 4.1.1 is particularly well adapted. It contains $m$ facilities (indexed by $\kappa$), $n$ demand or TOU blocks (indexed by $\theta$). The model is characterised by the following parameters:

\footnote{In this model, no monthly variations nor discount factor are considered, but these are straightforward to implement.}
Number of hours in demand block $\theta : H_\theta$,  
Cost per produced MWh by facility $\kappa : c_\kappa$,  
Capacity in MW of facility $\kappa : K_\kappa$.

Let $z_{\kappa \theta}$ be the energy flowing from facility $\kappa$ during the time slot $\theta$. If the timing of demands of type $j$ for consumer type $i$ were under direct control of the retailer, it would solve the following linear programme:

\[
\min_{\{z_{\kappa \theta}, x_{ij}(\theta)\}} \sum_{\theta=1}^{n} \sum_{\kappa=1}^{m} c_{\kappa} z_{\kappa \theta} \tag{35}
\]

under the following constraints:

\[
\sum_{\kappa=1}^{m} z_{\kappa \theta} - \sum_{i,j} x_{ij}(\theta) \geq 0, \quad \sum_{\theta} x_{ij}(\theta) \geq \beta_{ij}, \quad x_{ij}(\theta) \geq x_{ij}[\min](\theta), \quad x_{ij}(\theta) \leq x_{ij}[\max](\theta). \tag{36, 37, 38, 40, 41}
\]

These constraints correspond to the demand having to be met, the capacity having to be kept below its threshold, and the energy flows having to be positive. The dual variables for equations (36), (39), (40) and (41) are respectively given by $\pi_\theta$, $\eta_{ij}$, $\mu_{ij}(\theta)$ and $\nu_{ij}(\theta)$.

By applying the optimality condition for a linear programme and if the variables $x_{ij}(\theta)$ are in the optimal basis, meaning that their reduced costs must be zero, we get the following:

\[
\nu_{ij}(\theta) - \mu_{ij}(\theta) - \eta_{ij} + \pi_{\theta} = 0. \tag{42}
\]

This equation is to be compared with (34). The dual variable $\pi_{\theta}$ corresponds to the marginal production cost to satisfy demand. Therefore we conclude that (42) and (34) are identical. The other duality conditions would lead to similar complementarity conditions. Henceforth, the solution of the linear programme gives the optimal response of consumers to a marginal cost pricing.

Indeed the same result remains valid if one models the retailer over a long period with investment activities, as is done in the ETEM-SG model, for example (see e.g. [28]). In this case the price of electricity will be given by the long term marginal cost, which includes the investment cost.
4.4 Multilayer Game Models

The games’ structure considered in the previous subsections is occurring when different electricity customers are facing a supplier with a marginal cost pricing scheme. In [29] and [30] the game structure considered is more encompassing as it involves three layers of players, the customers (many), the retailers (a few competing to attract customers) and the producer (wholesale market actors). We will not develop this analysis any further because it does not correspond to the electricity market structure in Switzerland. The total realisation of the Swiss electricity market liberalisation would however require such models to be studied.

5 Optimal Distributed Charging and Storage Control for a Population of Electric Vehicles

In this section, the focus is placed on the use of dynamic TOU pricing or RTP schemes to foster the integration of BEVs or PHEVs in a Smart Grid environment.

As noted in [31], the electrification of transportation is often seen as one of the solutions to challenges such as global warming, sustainability, and geopolitical concerns on the availability of oil. From the perspective of power systems, an introduction of plug-in electric vehicles presents many challenges but also opportunities to the operation and planning of power systems: If vehicles charging operations are considered regular loads without flexibility, uncontrolled charging can lead to problems at different network levels endangering secure operation of installed assets. However, with direct or indirect control approaches the charging of vehicles can be managed in a desirable way, e.g., shifted to low-load hours. Moreover, BEVs and PHEVs can be used as distributed storage resources to contribute to ancillary services for the system, such as frequency regulation and peak-shaving power or help integrate fluctuating renewable resources.

In most of the proposed distributed control approaches, a so-called aggregator is in charge of directly or indirectly controlling the charging of vehicles and can serve as an interface with other entities such as the transmission system operator or the energy service providers. Communication thus plays a key role since, as in most of the control schemes, a significant amount of information needs to be transmitted between vehicles and utility management. This fits well in the paradigm of Smart Grids, in which an advanced use of communication technologies and metering infrastructure, increased controllability and load flexibility, and a larger share of fluctuating and distributed resources are foreseen.
5.1 Decentralised Control and Incentive-Based Coordinated Charging Control

Each BEV or PHEV is entering the market as an independent actor in the interaction between the utility providing the charging energy and the users deciding when to plug in their vehicles. Decentralised control schemes, based on game theoretic concepts, must thus be envisioned.

5.1.1 A Mean-Field Game Solution

In [32, 33], the decentralised control of a large population of BEVs or PHEVs (called PEVs hereafter) is considered. In [33], an adaptive real-time tariff is proposed as a way to achieve the optimal timing of recharging electric vehicles. Basically the situation is very similar to the ones addressed in sections 4.2 and 4.3. Adopting the notations of [33], the days are split time steps \( t \in \{0, 1, ..., T\} \). The relative state of charge of the \( n \)-th PEV at time \( t \) is denoted by \( x_{n}^{t} \). The charging dynamics can thus be written as:

\[
x_{t+1}^{n} = x_{t}^{n} + \frac{\alpha_{n}^{n}}{\beta_{n}^{n}} u_{t}^{n} \tag{43}
\]

where \( u_{t}^{n} \) is the charging rate of the \( n \)-th PEV at time \( t \) (in MWh/timestep), \( \alpha_{n}^{n} \) is the charging efficiency for the \( n \)-th PEV, \( \beta_{n}^{n} \) is the battery size of the \( n \)-th PEV (in MWh) and \( x_{0}^{n} \) is a given initial state of charge for the \( n \)-th PEV. The aim of the charging strategy is to get all PEVs charged at the end of the period:

\[
x_{T}^{n} = 1. \tag{44}
\]

Let \( D_{t} \) be the aggregate non-PEV base demand at time \( t \). We assume that the retail price is based on the marginal cost pricing scheme. The price will thus be an increasing function of the ratio of total demand to total electric generation capacity, denoted \( C \):

\[
p \left( \frac{D_{t} + \sum_{n=1}^{N} u_{t}^{n}}{C} \right). \tag{45}
\]

The daily cost for the \( n \)-th PEV is thus given by:

\[
J^{n}(u) = \sum_{t=0}^{T-1} p \left( \frac{D_{t} + \sum_{m=1}^{N} u_{t}^{m}}{C} \right) u_{t}^{n} = \sum_{t=0}^{T-1} p \left( \frac{d_{t} + \text{avg}(u_{t})}{c} \right) u_{t}^{n} \tag{46}
\]

which is the same equation as (25) and where \( d_{t} = D_{t}/N, \) \( c = C/N \) and:

\[
\text{avg}(u_{t}) = \frac{\sum_{n=1}^{N} u_{t}^{n}}{N}. \tag{47}
\]
In this model each PEV is a player in a dynamic non-cooperative game. One should thus tries to characterise a Nash equilibrium. As usual for control and open-loop Nash equilibrium problems (see e.g. [34]), the following Hamiltonian is introduced, for PEV \( n \):

\[
H^n(\lambda_{t+1}^n, x_t^n, u_t^n) = p \left( \frac{d_t + \text{avg}(u_t)}{c} \right) u_t^n + \lambda_{t+1}^n \left( x_t^n + \frac{\alpha^n}{\beta^n} u_t^n \right).
\]  

(48)

At a Nash equilibrium, for each PEV \( n \) the following first order optimality conditions holds:

\[
0 = \frac{\partial}{\partial u_t^n} H^n(\lambda_{t+1}^n, x_t^n, u_t^n) = p \left( \frac{d_t + \text{avg}(u_t)}{c} \right) + p' \left( \frac{d_t + \text{avg}(u_t)}{c} \right) \frac{u_t^n}{cN} + \lambda_{t+1}^n \frac{\alpha^n}{\beta^n}.
\]  

(49)

The adjoint equation of which being given by:

\[
\lambda_t^n = \frac{\partial}{\partial x_t^n} H^n(\lambda_{t+1}^n, x_t^n, u_t^n) = \lambda_{t+1}^n.
\]  

(50)

with transversality condition

\[
\lambda_{t+1}^n = \zeta^n,
\]  

(51)

where \( \zeta^n \) is the Lagrange multiplier associated with the constraint \([44]\) for the \( n \)-th PEV.

In this game each player reacts to the average decision taken by the set of all players. When the number of players becomes large, the decision of one player has a small impact on the average of all decisions and the optimality condition simplifies. In the limit where \( N \to \infty \), while \( c \) and \( d_t \) remain finite, which is representative of a large fleet of PEVs, the conditions which determines the optimal charge \( u_t^n \) is thus given by:

\[
0 = p \left( \frac{d_t + \text{avg}(u_t)}{c} \right) + \zeta^n \frac{\alpha^n}{\beta^n}.
\]  

(52)

At the limit, each player (i.e. each PEV \( n \)) plays against the average of all other players. This is a situation very similar to a competitive equilibrium, as already visited in section 4.3 The control community calls such a dynamic game structure a Mean-Field Game, see [35, 36, 37]. The obtained solution is also called a Mean-Field Nash Equilibrium.

5.1.2 A Decentralised Control Scheme Based on RT Pricing

Let us modify slightly the cost function of the agent controlling the \( n \)-th PEV:

\[
J^n(u) = \sum_{t=0}^{T-1} \left\{ p \left( \frac{d_t + \text{avg}(u_t)}{c} \right) u_t^n + \delta(u_t^n - \text{avg}(u_t))^2 \right\},
\]  

(53)
where $\delta$ is a given non-negative constant, common to all agents. The presence of $\delta$ is penalising the strategies that depart from the average strategy. In [33] it is shown how a decentralised control is implemented through a charging negotiation procedure, which takes place at some time prior to the actual charging interval. The introduction of $\delta$ may be necessary for the negotiation process to converge. The negotiation procedure is the following, quoting [33]:

**Step 1** The retailer broadcasts the prediction of non-PEV base demand $d_t$ to all the PEV agents,

**Step 2** Each of the PEVs proposes a charging control that minimises its charging cost with respect to a common a-priori aggregate PEV demand broadcast by the utility,

**Step 3** The retailer collects all the individual optimal charging strategies proposed in step 2, and updates the aggregate PEV demand corresponding to the proposed charging strategies. This updated aggregate PEV demand is rebroadcast to all of the PEVs,

**Step 4** Repeat steps 2 and 3 until the optimal strategies proposed by the agents no longer change.

When the actual charging start time is reached, each PEV will implement the optimal strategy obtained from steps 1-4. In the negotiation procedure each of the PEVs independently updates its own optimal feedback charging strategy with respect to the one-dimensional average value of all PEV agent strategies. At convergence, if it occurs, the collection of proposed individual charging strategies is a Mean-Field Nash Equilibrium, see [33]. Figure 12 illustrates the valley-filling effect due to PEVs.

![Figure 12: Illustration of the valley-filling due to PEVs, the solid pink line corresponds to $D_t$. On the left, negotiation strategies do not converge due to a too small value of $\delta$.](image-url)
5.2 Optimal Storage and V2B Operations

5.2.1 Example of V2B Operations

As argued in [38, 39], there are also new opportunities offered by correlating the movement of cars in a city and the movement of the power load. BEVs/PHEVs may be used to feed power back to home or office buildings; this is known as Vehicle-to-Building (V2B) operation. Such operation can be used either for demand response (DR) during peak load or for outage management during faults of the distribution system.

**Simple economics of DR** In [39] the authors consider a garage for a large commercial building where 80 vehicles arrive at 8:00 am and stay until 17:00. The garage is equipped with a bidirectional charger and controller. It can then play the role of an aggregator and charge the car batteries when the building demand is below peak load and discharge the batteries to partially supply the building to reduce the peak demand.

One assumes that there are two charge rates that vary during the day: \( r_1 \) and \( r_2 \), respectively corresponding to mid-peak and on-peak periods, and a monthly demand charge \( r_p \) which applies to peak power demand. The monthly revenue from DR is thus given by:

\[
G = E_{ec} (r_2 - r_1) \times \vartheta + r_p (P_{\text{max}} - P_{\text{DR}}^{\text{max}}) \tag{54}
\]

where \( E_{ec} \) is the energy shifted from on-peak to mid-peak time, \( \vartheta \) the number of days in month, \( P_{\text{max}} \) the maximum on-peak demand (kW) and \( P_{\text{DR}}^{\text{max}} \) the new maximum on-peak demand after the DR (kW).

As an example, let us consider 80 cars, each having a 15 kWh battery, and use the electricity tariffs exposed in 2.5.1: \( r_1 = 0.09 \) CHF/kWh, \( r_2 = 0.15 \) CHF/kWh and \( r_p = 6.80 \) CHF per maximum on-peak kW. The cars are fully charged at night, when the off-peak rate is the lowest. In the morning the garage is charging the batteries, at mid-peak rate and the energy is shifted to the afternoon, thus reducing both the energy and the peak demand bill. A safety 6kWh energy level is maintained in each battery to allow for the return trip of the driving cycle.

In this example 720 kWh of energy is shifted (80 times 9 kWh), and the maximum on-peak demand reduces by roughly 225 kW. Hence, according to (54) the monthly revenue is 2394 CHF, for a month of 20 weekdays. Notice that the major part of the revenue comes from the reduction of the peak-demand charge (1530 CHF).
5.2.2 Economic Analysis of the Use of Storage Provided by Idle PHEVs Based on Locational Marginal Pricing

- Profitability of temporary storage activities, based on current zonal marginal prices

In [40] it is claimed that the potential benefits to users will not be sufficient to provide incentives for using BEV or PHEVs for temporary energy storage. A very detailed analysis is based on the assumption that the vehicle owner is charged under a real time pricing (RTP) scheme, which is obtained by adding a transmission and distribution cost of 0.07 $/kWh to the hourly nodal price that permit the computation of locational marginal price (LMP). These prices reflect the congestion occurring on the transmission network and reflect the real economic value of each kWh stored at different times of the day by vehicles connected to the different hubs of the transmission grid. In [40] the authors use LMP data published by three American cities (Boston, Rochester and Philadelphia) and simulate the optimal use of storage capacity of PHEVs by the owners. They observe a very low yearly profit (typically in the range $10-50), which could not be a credible incentive to participate in this trade.

This analysis, reported in [40] seems to contradict the analysis of [39] summarised above in 5.2.1. A closer look shows that in both cases the trading of energy is not profitable. In the example of 5.2.1 it was mostly the component of tariff based on the maximum on-peak demand which was generating profit from demand shifting. In conclusion, it seems that the zonal prices used in [40] where not reflecting the same economic value as the one characterising the reduction of the maximum on-peak demand as in the commercial tariff mimicked in 5.2.1.

- Profitability of temporary storage activities, based on prospective nodal marginal prices.

The same analysis, in a prospective context, with nodal prices reflecting congestions due to increased use of renewable energies, like solar and wind to produce electricity, could lead to different conclusions. The computation of nodal prices is shown to be obtained from the dual solution of the optimal dispatch problem under constraints of capacity of the transmission network. This development is based on the papers by Ruiz et al. [42, 43, 44] and Stiel [45] and is exposed in the following.

It is possible to define a linear power flow model to describe the distribution of power in the different lines of a transmission network, i.e. a linear relation

\[ P_f = \Psi(P_G - P_L), \quad (55) \]

where \( P_f \) is the vector of power flows on each line of the network and \( P_G - P_L \) is the vector net power injection (generation power \( P_G \) minus load \( P_L \)) at each node.
bus (node) of the network. The transmission sensitivity matrix $\Psi$, also known as the injection shift factor matrix, gives the variations in flows due to changes in the nodal injections. The shift factor matrix is a function of the characteristics of the transmission elements and of the state of the transmission switches. For a given point in time, the system operator dispatches the committed units so as to minimise the total costs of operations. Assume that the generation costs are piecewise linear, and denote the vector of nodal generation annualised costs in CHF/MWh by $c_G$. The economic dispatch solved is a linearised lossless DC optimal power flow (OPF) problem, formulated as a linear programme:

$$\text{minimise} \quad c_G^T \cdot P_G$$

under the following set of constraints:

$$1^T (P_G - P_L) = 0 \leftrightarrow \lambda, \quad (57)$$

$$P_{f\text{min}} \leq \Psi (P_G - P_L) \leq P_{f\text{max}} \leftrightarrow \mu_{\text{min}}, \mu_{\text{max}}, \quad (58)$$

$$P_{G\text{min}} \leq P_G \leq P_{G\text{max}} \leftrightarrow \gamma_{\text{min}}, \gamma_{\text{max}}, \quad (59)$$

where $1$ stands for a vector whose components are all equal to 1. The constraint (57) ensures the total load-generation balance, (58) enforces the flow limits on transmission elements and flowgates, where lower limits usually represent the limit in the opposite flow direction, and (59) models the lower and upper generation limits. The dual variables are indicated next to the corresponding constraints.

In [44], the nodal marginal prices is then derived:

$$\pi = -(\lambda 1 + \Psi^T (\mu_{\text{max}} - \mu_{\text{min}})). \quad (60)$$

So, if we introduce the dispatch problem description in a linear programming model like ETEM-SG [28], the implicit nodal price given by (60) will serve to guide the potential use of BEVs or PHEVs for temporary storage and for charging.

5.3 Other Ancillary Services Provided by EVs

In Refs [46], [47] and [48] it is shown how electrical vehicles can be used to provide ancillary system services, like frequency and voltage stabilisation and load following power injection. These activities may have significant economic value, however a relative small number of BEVs seems to be needed to provide those services, as noted in Ref. [40].

6 Conclusion

This report has focused on the economic rationale of dynamic adaptive tariffs that will necessarily be introduced when a Smart Grid concept is implemented, in the context
of major renewable energy development and important penetration of plug-in electric vehicles. After having reviewed and reported in these pages some of the most recent international contributions to the economic analysis of smart-grids and their pricing schemes, we arrive at the following observations:

- Variable tariffs, also called Time-of-use pricing, are already in use in several countries, including Switzerland. A few econometric analyses have permitted the assessment of their relatively small effect on demand shifting and peak-load reduction.

- Much higher price elasticities are expected when a Smart Grid scheme is implemented and households are provided with devices (home computers) permitting an optimal timing of flexible loads based on real time prices.

- The issue of public acceptability of two-way communication of energy and price data and their use in regulating daily electricity usages is posed and some survey analyses will have to be done to get a better grasp at this delicate question. Conjoint analysis seems to be the technique that could be used to exploit the result of surveys concerning acceptability of new technologies.

- For planning purpose one has to represent demand-response in the prospective supply-demand equilibrium models. The Çelebi and Fuller model exposed in subsection 4.1 is particularly convenient if we can model the dynamic adjustment of the electricity demand law, using hereditary and price elasticity effects.

- Another approach, exposed in 4.2 consists in representing the optimisation problem concerning the optimal timing of the usages which is solved by the consumer when a new tariff is announced. The situation has the structure of a non-cooperative game for which a unique Nash equilibrium exists. When the number of customers increases, each customer having less influence on the price determination, the Nash-equilibrium tends to become a market equilibrium. It is possible to show that the optimal demand-response can be represented in an energy model structured as a mathematical (or linear) programming model, by simply representing the constraints of the optimal timing problem in the global energy model. This approach will be implemented in the ETEM-SG model that has been recently developed to model energy planning decisions in a context of Smart Grids deployment in the Arc-Lémanique region and the Canton of Bern [49].

- The possible massive penetration of electric vehicles poses a challenge to the electric grids. Real-time pricing schemes should be used to ensure that the recharge period for electrical vehicles remains in the off-peak period, so that this new load will have a “valley-filling” effect on the regional power system load curve. Here again the interactions between the utility and the vehicle owners is a non-cooperative game where each player reacts to the average action of the other
players, a structure called “mean field game” which corresponds grossly to a competitive economic equilibrium.

Plug-in electric cars will also offer temporary storage services. With the current electricity tariffs this activity could prove to be profitable in a V2B system, when the business organisation has an important part of the tariff which is determined by the peak-demand load. If the tariff seen by the vehicle owner is only the zonal marginal price of electricity, the current values for these prices do not seem to provide a sufficient potential profit to the owner entering this type of temporary storage transaction. However the future zonal marginal prices, when a very large penetration of renewable energy technologies has taken place, could be quite different from what they are today and the temporary storage business could develop under these new circumstances.

In conclusion we are comforted in our conviction that dynamic electricity pricing will develop simultaneously with the diffusion of smart metering systems and with the penetration of renewable energy generation technologies and the diffusion of electric vehicles with plug-in batteries. Smart Grids will permit a large implementation of tariffs based on real-time-pricing, and home computers will facilitate the implementation of local optimisation of the timing of demand, battery charging loads and temporary storage. The economic analysis of these pricing schemes has shown that they lead to some form of competitive market equilibrium, which can be easily represented in energy models like ETEM-SG. These models should then be able to anticipate the potential impact of Smart Grids on the future supply-demand equilibrium for electricity in different regions of the country. However a big unknown still exists; it concerns the acceptance by the end-users of smart-grid protocols involving day-to-day consumption usages and management of the vehicle battery. This will be explored in a survey during the second phase of this research project.
References


