Investments in a renewables only market

Market model in a future electricity market without fossil fuels

Rotterdam, 15 September 2017

Summary

Introduction

Currently, investments in renewables far exceed investments in conventional generation in the Netherlands and other European countries. This implies that the majority of investments in the electricity market is not based on price signals alone but on subsidies.

Some market observers worry that this dependency on subsidies is not a temporary phenomenon but a structural feature of the future European electricity market (even after the energy transition has been completed). The reason is that wind and solar energy have low marginal costs; as prices are generally set based on marginal costs this may result in low electricity prices and diminished incentives to invest.

To analyse this question TenneT has commissioned Ecorys to study the economics of a 100% renewables market and to advise on the optimal market model. The study focuses on a future market that has completed the energy transition and consists only of renewables. We analyse the investment incentives and the optimal market model in such a "renewables–only" market. Alternative market models are evaluated based on the following criteria:

- The model should guarantee *security of supply* (to a similar level as in today's market)
- The model should be as much as possible *based on the market mechanism*
- *Efficiency* (lowest costs to society)
- *Flexibility* (can the model be adjusted to changes in market)
- *Complexity* (as simple as possible and feasible)

Point of departure for our analysis is a world where fossil fuel based electricity generation is either not allowed or CO_2 price levels are so high that conventional assets are not profitable. In this report we ignore the costs and benefits of the future energy system but focus on the question how producers of renewable energy will be remunerated.

We have based our analysis on the small but rapidly developing literature on this topic, an assessment of experiences in other markets (notably telecoms and media) and interviews with 15 market experts including academics and market participants

Theory and experiences in other markets

Our analysis starts with a theoretical perspective on incentives to invest in a market with low marginal costs. Many practitioners in the electricity market explicitly or implicitly assume that prices are always equal to marginal costs. This thinking is based on the 'merit order model'. However, basic economic theory predicts that in the long run prices need to exceed the average total costs of production in order to keep generators in the market or attract new ones. So while prices respond to scarcity in the short run, in the long run the supply curve is upward sloping as investors demand positive prices and a return on their investment. At least theoretically, this way markets provide incentives for investments in renewable energy even when marginal costs are low. In practice, market outcomes may differ from the theoretical ideal. All markets show some degree of “market failure”. In the electricity market explicit or implicit price caps can for example result in ‘missing markets’. Despite these market failures many markets come to acceptable outcomes.

Experiences in other markets with low marginal costs show that companies do invest, even if there are no subsidies. An example is the market for mobile telecommunications. Although the costs of an additional call or additional download or negligible, prices for consumers are not. Operators are able to operate a network profitably by charging prices that exceed marginal costs.

Revenue models

The experiences in other markets show that companies use a variety of revenue models if marginal costs are low. Does that mean that similar revenue models will also be used in the electricity market? Electricity suppliers around the world already offer numerous propositions to small and large consumers. These revenue models fund investments in renewable electricity assets. For producers, prices on the wholesale market remain the benchmark for their investment decisions. Only if producers (including prosumers) expect that future prices will result in revenues that provides them a return that exceeds the cost of capital will they decide to invest.

Market model

It is likely that a shift to production with low marginal costs will result in new revenue models in the market. Does that also imply that ‘the rules set by governments and regulators and the associated role of competitive markets’ (the market model) needs to be changed?

We evaluate what kind of market model is able to deliver incentives to invest in renewable energy and to guarantee a high level of security of supply. This model must be able to accommodate the needs of producers and consumers as well as intermediaries and integrated energy suppliers.

We consider three “categories” of market models. Within each category there are many different models possible.

- Model 1: central planning and control of the system (“single buyer”);
- Model 2: a market with centralized rules regarding the specific pricing structure to be used in wholesale and retail markets in addition to the ‘energy-only market’;

- Model 3: a market in which producers and consumers have freedom to use their preferred pricing structure (often referred to as an 'energy-only market'[1]).

We conclude that model 1 will not work in a market with numerous producers and possibilities for demand response and storage. Moreover, it does not meet the criteria outlined above (e.g. being market based and efficient). A common characteristic of various models that can be grouped under model 2 (for example 'capacity markets') is that the government tries to steer market outcomes. In practice, this is complicated as the government (and TSO) does not have perfect information and it can result in inefficiency. Although such models may result in higher reliability, this comes at a cost.

In markets with no or limited regulations regarding pricing there are generally a variety of revenue models. Model 3 reflects this and leaves it to producers, suppliers and consumers to use their preferred pricing or revenue model. Model 3 offers the perspective to benefit from the advantages of the alternatives discussed under Model 2 without the disadvantages as there is less complexity and more flexibility for all market participants. The risk that consumption and investments decisions are distorted in an inefficient way is also lower. In many ways this model is an evolution from the current model rather than a revolutionary change. The details of this model (which is not identical to the current model) are further outlined in this report.

Conclusion

We conclude that we expect a 100% renewables market to provide adequate investment incentives even without government subsidies.

We do not propose any specific regulatory change in the allowed price structure or revenue model as there are risks that this would result in less efficiency, complexity, less flexibility and diminished incentives to innovate. Moreover, developments in the market such as increased opportunities for demand response and storage may be hampered if the pricing structure is poorly designed.

Our conclusions do not only apply to our scenario with 100% renewables and substantial demand response and storage options but to some extent also in the transition towards a market with 100% renewables. This does not rule out any interventions (e.g. capacity mechanisms or other interventions) during the transition phase towards a fully renewable market. However, arguments for market interventions in a renewables-only market are less convincing than *during* the transition. A key

[1] In the remainder of this report we do not use this term as it suggests that there are only transactions based on a certain volume of electricity. Freedom to use different kinds of pricing structures means that pricing structures not based on energy (MWh) may play an important role, but not as the result of government intervention. For example, prices may be based on capacity (MW).

reason is that the degree of uncertainty is much higher during the transition than after the transition.

Based on our analysis the optimal strategy is to improve the functioning of the price mechanism. In the main report we discuss a number of measures that can be considered. These policy recommendations are also applicable in a market that is still transitioning. In that sense they can be considered no-regret options.

Introduction

In the current market a high share of investments in generation assets is subsidised

The electricity market is undergoing a major transformation as the penetration rate of renewables increases. Currently, investments in renewables far exceed investments in conventional generation in the Netherlands and other European countries. Investments in renewables are an attractive investment as governments provide subsidies and tax incentives that compensate for the difference between market prices and costs. This implies that the majority of investments in the electricity market is not based on price signals alone but on public policies. As the IEA in a recent report explains this is quite a remarkable development against the background of deregulation and market liberalisation in the preceding decades.[3]

When renewable assets enter the market they produce electricity when the wind blows or the sun shines. Contrary to fossil-fuel assets their marginal costs of producing electricity are low. It is likely that the additional supply in the market, with low marginal costs, has contributed to lower average electricity prices. Somewhat paradoxically these lower prices may require higher subsidies (even taking into account expected cost reductions) as investors need to be compensated for the gap between market revenues and total costs.

TenneT is interested in the question if the dependency on government subsidies is a temporary phenomenon or a structural feature of the future European electricity market (even after the energy transition has been completed). To analyse this question TenneT has commissioned Ecorys to study the economics and optimal market model in a world that has completed the energy transition. Energy generation in this world consists only of renewables. We have been encouraged by TenneT to think beyond current discussions on the market model and to focus on what is needed in a scenario where fossil fuels are out of the picture and renewables are the norm.

Alternative market models are evaluated based on the following criteria:

- The model should guarantee *security of supply* (to a similar level as in today's market)
- The model should be as much as possible *based on the market mechanism*
- *Efficiency* (lowest costs to society)
- *Flexibility* (can the model be adjusted to changes in market)
- *Complexity* (as simple as possible and feasible)

[3] IEA (2016), "Re-powering markets, market design and regulation during the transition to low-carbon power systems"

We do not consider any distributional impact of a 100% renewables market (e.g. the impact on low income households).

Our approach is based on a literature review and interviews with market experts

We started this project with a review of the still limited but rapidly developing literature on this topic. Subsequently, we have interviewed about 15 market experts including academics and market participants. In this report we have synthesized the findings in the literature and the views that were brought forward in the interviews.

The terms "market model" and "market"

In this report we often refer to the "market model". We define the market model as: *the rules set by governments and regulators and the associated role of competitive markets.* As Table 1 shows a market model has multiple dimensions. In this report we concentrate on the dimensions that affect how production assets are remunerated and the way in which consumers pay for electricity. We assume that renewables are the norm – fossil fuel based electricity generation is either prohibited or prohibitively expensive due to carbon pricing. Our main interest concerns wholesale markets but we will also go into retail markets as developments in those markets can influence wholesale markets.

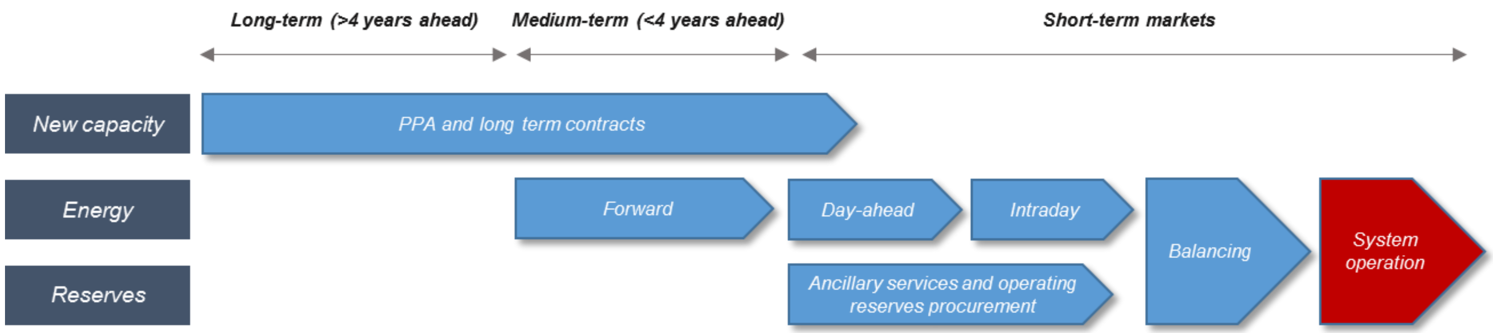
Table 1 - Relevant dimensions of market model or market frameworks

Policy	Examples of Regulation/ use of price mechanism	Main focus study
Carbon pricing	*Carbon regulation and trading*	
Support schemes	*Support schemes renewables*	✓
(short-term) wholesale energy markets	*Market/trading rules, energy prices, scarcity pricing, reliability standards*	✓
Capacity markets	*Capacity requirements, prices*	
Price/tariff regulation retail market	*Retail pricing, taxation and levies*	✓
Network regulation	*Planning, cost allocation, auctions*	

Note: Based on OECD/IEA, 2016

We often use the term “market” in this report. Generally speaking, the electricity market is characterised by many different sub-markets, depending on the product that is bought and sold (energy, capacity, or a service) and the relevant time horizon (varying from the “close to real time” market to the forward market where electricity is sold years before the actual production). The Figure below provides a graphical summary of the different markets. Our analysis takes all potential markets into account that contribute to a viable business case of an electricity generator.

Figure 1 – Building blocks of electricity markets



Outline of this report

In the next chapter ("Scenario") we introduce the only scenario that we use in this study, this is a future scenario that describes a world with only renewable, low marginal cost, generation assets.

After the introduction of our scenario for the future energy market, chapter 3 ("Market mechanism") provides a theoretical discussion on incentives to invest in markets with low marginal costs.

In chapters 4-5 we turn to the revenue models that might be used by producers in a 100% renewables market. In chapter 4 ("Other markets") we first look at revenue models in other markets that also exhibit low marginal costs. Next, we explore what kind of revenue models might emerge in the electricity market in chapter 5 ("Revenue models"). These revenue models should ultimately also result in a profitable business case for investments in electricity production.

Chapter 6 ("Market model") discusses if the rules set by governments and regulators and the associated role of competitive markets (the market model) need to be changed compared to the current situation.

Our scenario assumes that there are only renewables in the market. This scenario requires a transition from today's market in which fossil-fuel production is dominant. In chapter 7 ("Transition") we discuss if the conclusions on the market model in chapter 6 for a 100% renewables market are also applicable in the transition towards a market with only renewables.

Scenario

We imagine a future world where fossil fuels are not used anymore to generate electricity. We consider this scenario as a thought experiment, not as a projection or forecast

In order to analyse the implications of an increasing share of renewable energy assets with low marginal costs in the system we use a single scenario or "thought experiment". Overleaf we have listed the characteristics of the electricity market that we study in this report.

In our scenario we assume that fossil fuels are not in the picture because they are not allowed or CO_2 price levels are so high that conventional assets are not profitable. Based on current technologies, it is likely that such a scenario results in (much) higher system costs (as well as societal benefits). Renewable technologies are more expensive than fossil fuels and additional generation, storage or demand response is needed to cope with the intermittency of many renewable technologies. In this report we ignore the costs and benefits for the system but focus on the question how producers of renewable energy will be remunerated if there are no fossil-fuel production facilities in the market.

Storage will be a part of the future electricity market, but the share of storage and its costs are still highly uncertain. The same holds for demand response which is also expected to play an important role.

Our scenario – a 100% renewable electricity market

- Renewable energy is the norm. For the sake of argument it helps to start with the assumption that the marginal costs of all renewable energy production is low.
- The use of fossil fuels is either not allowed or CO_2-prices are at a level where investments in fossil-fuel generation capacity are not profitable.
- We do not consider nuclear energy.
- Demand response and storage (including Power-to-X technologies) are an important part of the electricity market.

Both storage and demand response can have marginal costs above zero which (in those cases where they set the price) may have a positive impact on the remuneration of energy generation with low marginal costs.

It is uncertain to what extent technologies with low marginal costs will be dominant or that other technologies will be used extensively as well (e.g. biomass). For the sake of argument it helps to start with the assumption that the marginal costs of all renewable energy production is low. If there are incentives to invest in such an extreme scenario there are also sufficient incentives to invest in a more realistic scenario with a variety of production technologies with different cost curves.

Future technological developments in storage and demand response technologies will be an important determinant of the type of energy market in the scenario, as the IEA also points out.[4] For example, electricity prices may be significantly more volatile in a world depending heavily on wind and solar power for electricity generation than in a world where a diversity of technologies mature (including storage and demand response). In the latter case, with relatively cheap storage and demand response, the electricity market may more closely resemble the gas market. In that market production and supply do not have to balance at all times as gas can be stored.

[4] IEA (2016), “Re-powering markets, market design and regulation during the transition to low-carbon power systems”, p. 46-47.

Market mechanism

Basic economic theory predicts that supply will match demand. However, this requires some strong assumptions

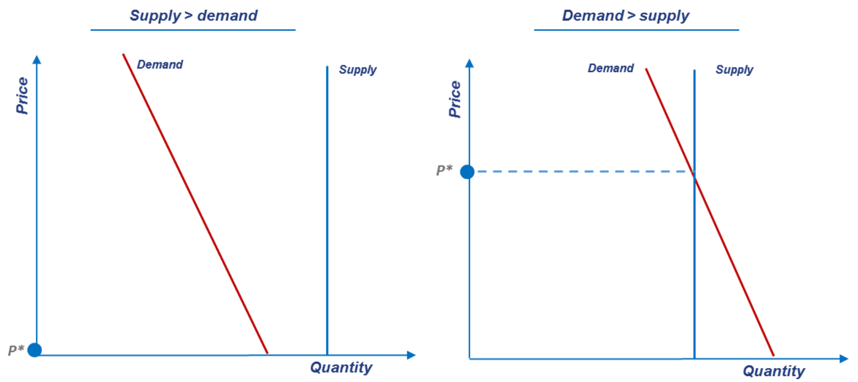
Most energy market participants have obtained experience in a market where the “merit order model” was the dominant way of thinking about electricity supply and price formation. In this model generation assets are dispatched if the marginal revenues of a plant exceed marginal costs. A similar model is taught in one of the first lectures of every basic course in economics, the optimal pricing strategy of a producer in this model is to set prices at a level where marginal revenues equal marginal costs. In our scenario with only low marginal cost renewables this price strategy would result in prices close to zero.

If prices are zero there would of course be no incentive for producers to invest in assets. This brings us to a second condition that prices should not only be based on marginal costs but also reflect the long run average costs of production (including a return on invested capital). If prices are lower than long run average costs producers do not make a sufficient return on their investment. In such a situation producers will not enter the market and eventually leave it if prices are not expected to increase (depending on whether prices are structurally below marginal costs or below average total costs). If sufficient producers leave the market the remaining producers will receive a higher market price that may exceed their marginal costs. Over time, as the reduction in capacity raises prices and results in above-normal returns, new producers will enter the market. In other words, even if the short run supply curve would result in prices close to zero, the long run supply curve would still be upward sloping (supply increases with prices).

In fact, even in the short term it is unlikely that the market always clears at a price close to zero as demand will exceed supply at certain hours. Another way of looking at this is from the perspective of a producer that has a single wind turbine and wants to sell electricity in forward markets. If this producer would agree to a price of 0.0 euro per MWh in the forward market it would have to deliver the electricity at the agreed point of time. However, if the wind does not blow at that time it has to get electricity from someone else (and pay for it). This means that it is not rational for the producer to agree on a price of 0.0 euro – it would mean accepting a risk without compensation while forgoing the opportunity to sell the electricity for a higher price.

Figure 2 illustrates the discussion above. In a market with only low marginal cost producers the supply is ‘perfectly inelastic’ and the supply curve is vertical (the underlying assumption is that capacity cannot be changed in the short term). Some consumers are able to reduce their energy consumption, the demand curve is downward sloping. If supply exceeds demand (for example in weekends or during the night) prices are close to zero. During other hours demand can exceed supply. The equilibrium price can be found by going along the demand curve. The resulting price level (*P**) exceeds marginal costs for all producers. These revenues, generated during hours in which demand exceeds supply, should be sufficient to recover investments. If that is not the case producers will not enter the market or re-invest.

Figure 2 – market prices exceed marginal costs when demand exceeds supply



Note: the supply curve shows the relationship between the price and the quantity supplied in the market, not the bids or marginal costs of individual suppliers

The below example illustrates *how* the high price outcome shown in Figure 3 could be reached in the bidding process.

Figure 3 – market prices exceed marginal costs when demand exceeds supply

Supply		*Demand*	
P (EUR/MWh)	**Q**	**P (EUR/MWh)**	**Q**
0.01	1000	40	3000
		45	2000
		50	1200
		55	1100
		60	1000
		65	950

In the example in figure 3 total production is 1,000 MWh. As producers do not have marginal costs they are willing to sell at any positive price. However, there are buyers on the market that are willing to buy at a price significantly above the marginal costs of producers. The market clears where demand equals supply (in the example at 60 EUR/MWh) even though producers are willing to sell at a price of 0.01 EUR MWh.[6] In markets without an auction but with a pay-as-bid mechanism and continuous trading the same logic applies. However, in such markets producers have to base their bid on their

[6] Note that there might be technical reasons why trading algorithms do not result in the theoretical equilibrium price (P* in figure 2). Block and complex orders can for example result in market outcomes that deviate from the theoretical social optimum.

expectation of the market clearing price as the price they receive is equal to their bid. This requires sufficient liquidity in the market as otherwise prices will be very sensitive to changes in weather conditions (in the hypothetical market with only intermittent renewable sources).

The model that we presented above is of course too simplified. However, advanced models of the power market, for example of the IEA, arrive at a similar prediction that prices can rise above the marginal costs towards the long term average costs of generation assets under certain conditions.[7] Although these models are more advanced than our simple "model" they depend on similar assumptions. The most important of these assumptions are:

1. Producers (and consumers) are rational;
2. Producers (and consumers) have perfect foresight and access to all information;
3. There are no restrictions to enter or leave the market;
4. There are no restriction on prices; and
5. There are no externalities (costs or benefits that are not priced).

No market fulfils all theoretical conditions of a perfectly competitive market

In practice no market shows all the characteristics of the simple economic model of perfect competition. All markets show some degree of "market failure". Despite these market failures many markets come to acceptable outcomes. Often the remedies to market failure in the form of government intervention are not without costs ("government failure").

According to the literature, the two sources of market and government failure most relevant for the transition to the scenario with 100% renewables are:

1. It is not unlikely that our scenario of 100% renewables requires decades of government subsidization, potentially leading to an initial period of excess capacity and relatively low prices. Future investors might fear that even if the market reaches the scenario with only renewables governments will keep on interfering in the market. This creates regulatory risk. Likewise, (unexpected) reductions in the level of support for renewables might also create risks.
2. More variation in wholesale prices is likely due to a higher share of intermittent sources. There is uncertainty

[7] IEA (2016), "Re-powering markets, market design and regulation during the transition to low-carbon power systems". Page 43:
'By 2050, a market based on energy prices (energy-only market) with a carbon price could drive the transition to a low-carbon power system under certain scenarios. This might be the case if demand response continues to progress and storage costs fall, or if carbon and gas prices drive wholesale prices to a level high enough to recoup low-carbon investments costs, including a return.'

if producers can offer prices that exceed their marginal costs considerably. This may be the result of technical barriers or the perception that competition authorities or regulators will interfere if prices exceed a certain level. "Missing money problems" arise if there are explicit or implicit price caps (as in the current market) and they are set too low (below the actual Value of Lost Load, VoLL[8]), and ancillary services (flexibility, ramp-rates, frequency response, blackstart capability,etc.) and balancing services are inadequately remunerated.[9]

Within the context of our study an important question is if market failure is more likely in a scenario with 100% renewable energy than in the current market where the share of renewables is still limited. It is likely that after the transition the impact of one of the major sources of market failure will diminish, there is likely less regulatory risk as there is no need anymore to support specific technologies (see also chapter 'transition'). It is uncertain if and to what extent there will be more variation in wholesale prices as that will depend on the technology mix and the role of storage and demand response.

Current price developments in the market are not a template for our scenario

In the Western-Europe electricity market prices increasingly fluctuate based on weather conditions. Average prices have dropped as well resulting in losses for power producers and the closure of some production facilities. This development provides support to the argument that renewables put downward pressure on electricity prices. Although the investments in renewable capacity have contributed to lower prices in the past decade this does not mean that prices will also be low in our scenario with 100% renewables. In the current market subsidized renewables are an addition to existing fossil-fuel capacity, this has resulted in an increase in supply. This increase was not based on price signals but on the subsidies provided to renewables. Higher supply by production units with low marginal costs has contributed to lower prices (other factors such as the economic crisis have also contributed to it).

In our scenario the transition has been completed and governments do not intervene in the market.[10] This means that capacity will only be added if production facilities retire or if there is a change in demand. If demand increases this will be

8 The value of lost load is the amount consumers are willing to pay to avoid an interruption in the supply of electricity. In practice TSOs interfere to avoid a power outage. If the maximum price is below the costs of load shedding, consumers that contribute to excess demand are not charged the full costs to society (i.e. security of supply is an externality that is not fully priced).

9 Newbery, D. (2015), "Missing money and missing markets: Reliability, capacity auctions and interconnectors", Energy Policy 94

10 Some producers might still benefit from subsidies or other government interventions, those interventions are predictable and there is no uncertainty about new interventions.

reflected in prices, producers will only invest if they expect that average prices at the times the renewable asset generates electricity exceed the levelized costs of producing electricity.

Conclusion

In theory it is unlikely that in the long run prices will be structurally zero due to low marginal costs of production facilities. In the short run prices respond to scarcity, in the long run the supply curve is upward sloping as investors demand positive prices and a return on their investment. This way markets can, at least theoretically, provide incentives for investments in renewable energy, even when marginal costs are low.

However, in reality there may be market failures or government failures that may hinder the working of the market and investments in production capacity. The alternative market models that we will discuss in chapter 5 ideally would have to take away some or all of these failures.

In the next chapter we will first make a comparison between the electricity market and other markets where producers face no or very low marginal costs of production.

Other markets

Revenue models in other markets wth low marginal costs

Renewable electricity production is not the only production process that is characterised by low marginal costs. Digitalization has decreased the marginal costs of reproducing music, video and books. The digitalization process has increased the possibilities to apply a variety of pricing models. Cloud computing has for example enabled software vendors to apply the software-as-a-service pricing model.

In this chapter we describe some of the pricing models that are applied in telecommunication, railways and for software and digital content. These markets do not share the distinguishing characteristic of the electricity market that demand has to balance supply at every moment in time. Another difference is that in electricity markets some (small and large) consumers own production capacity themselves. Electricity is also a homogeneous good, the quality of the product does not differ between suppliers (although there are differences in services offered by suppliers.

Based on the examples described in this section, we conclude on the key elements of potential revenue models. In the next chapter, we then describe how these revenue models could work in the electricity sector.

Demand side - revenue models

Bundling/subscription-system

Consumers pay a fixed monthly price for limited or unlimited access to the content provided over a network. Examples are the data bundles of mobile providers. Similarly, Spotify (an online music streaming service) and Netflix (an online video streaming service) provide access to its full catalogue for a fixed monthly price.

"Freebie" strategy

Digital platforms and providers of digital content often provide access to their product for free to consumers. Companies such as Google and Facebook finance this strategy by charging companies that are active on the other side of the platform for advertisements.

Companies can also choose to offer their product for free in combination with other products. An example is the GPS-application on iPhones. This free application makes the iPhone platform more attractive to consumers. Apple can finance investments in its GPS-app by selling more iPhones.

Tiered pricing

In this pricing model the price of a basic product is relatively low but consumers pay for additional services. An example is a free app such as "Pokemon Go" or "Skype", they can be downloaded for free but consumers have to pay for some additional functionalities.

Mix of strategies

Companies often use a mix of pricing strategies. Telecom providers for example offer a diversity of bundles and prepaid plans with or without phone and with additional services attached (e.g. insurance; Spotify premium, etcetera). Some of these plans are sold as a bundle while the services can also be bought separately. Spotify offers a free version of its service in which users are confronted with advertisements and a paid version without advertising.

Newspapers are a classic example of a product with low marginal costs. Articles in a single issue of a newspaper are sold as a bundle. Blendle, an online service that offers online access to newspapers and magazines, provides the opportunity to buy a single article but has also introduced unlimited access to all newspapers on its website. Similarly the NS (Dutch railways) sells one-way tickets as well as annual or monthly subscriptions and discount plans.

Supply side - revenue model for the producer

In the previous paragraph we mentioned pricing strategies in retail markets. In those markets there is generally not as sharp a distinction between retail and wholesale markets as there is (to some extent) in the electricity market.[11]

In markets for digital content authors and producers are paid per download or for a bundle of movies/music albums. The major mobile operators have their own network and market it to consumers. The providers without a network pay for the use of the network which provides additional revenue to the owner of the network.

Without going into the details of the pricing structures used in these "wholesale" markets it is clear that there is not a single revenue model for producers (e.g. authors, network operators). Some producers have a business model based on volumes sold, others receive a fixed lump sum fee or a combination between fixed lump sum fees and variable fees.

[11] Integrated suppliers and consumers with own production facilities operate by and large outside wholesale markets.

Lessons for the revenue model in (retail) electricity markets

The experiences in the telecom industry show that new business models are not introduced overnight, but gradually develop over time as companies refine their strategies in response to developments. For example, when the UMTS technology was introduced in the previous decade many mobile operators offered plans without data limitations (but with a fair use policy). This turned out to be a loss making revenue model with the widespread adoption of smartphones. However, in the fixed line and cable market it is still the dominant pricing strategy to offer plans without capacity restrictions. With the adoption of the 4G technology in the mobile market some operators have re-introduced plans without capacity ceilings. This shows that pricing strategies are not static but that companies respond to changes in their cost structure, changes in consumer preferences and technological developments.

The examples for the telecoms industry and also other markets show the complexities of revenue models. In practice companies offer a wide array of pricing policies depending on:

- The “production costs” of different products;
- The preferences and willingness to pay of users;
- The risk appetite of producers and users.

By differentiating their products and revenue models, producers in the telecoms industry have been able to profitably serve very different market segments.

In most of the markets that we discussed in this chapter governments do not interfere in the market to set price levels. The only legal restrictions that companies face in their price setting are general competition rules. An exception is the telecommunication market where there is sector specific regulation regarding the tariffs that operators can charge for cross-border calls and data use, as well as for accessing the network and call termination. In contrast to the electricity market there is no specific taxation (except for value added) in the markets discussed.

In sum, although marginal costs in telecoms and the production of digital content are low there are still incentives to invest.[12] Sometimes variable prices are low combined with higher fixed costs but this is not always the case. Apparently, producers and consumers favour a variety of pricing structures providing incentives for producers to differentiate their service offerings to tailor them to specific target groups.

[12] Note that it is more difficult to ascertain whether investments are at an “optimal” level as excess demand or excess supply are in many cases less visible than in the electricity market.

Determinants of the revenue model of a company:

Cost structure
No company can survive if revenues are lower than the average total costs of production. In competitive markets prices tend towards the long run (total) costs of production.

Market power
Companies that have market power can ask a higher price than a company that operates in a competitive market. A company with market power will consider the willingness to pay (elasticity of demand) of consumers in its price setting.

Transaction costs
Frequent price changes are costly to some extent for all market parties. In an electricity market without smart meters it would be too expensive to apply prices that change on a daily basis for example (a consumer would need to read the meter value every day). With smart meters the transaction costs have dropped significantly but consumers will (implicitly) still consider the time that it takes to monitor prices, some will decide that it is not worth the effort to respond actively to price changes and will prefer a contract with fixed prices or an automated response (e.g. taken care of by a service provider).

Allocation of risks and incentives to reduce costs/risks
The way products and services are priced influences the distribution of risks. In a mobile telecommunication price plan without a data limit the provider bears the risk of volume fluctuations for example whereas in pre-paid plan consumers face the risk.

Revenue models

Future revenue models of suppliers and producers

Introduction revenue model renewable producer

In this chapter we discuss revenues model of renewable electricity producers. We analyse what kind of profitable revenue models could emerge for investments without any subsidies in a future renewables-only market.

As the revenues ultimately depend on consumer demand we first discuss revenue models on the demand side of the market, in a contract between a supplier or producer and a consumer/user. We finish the chapter by analysing what the revenue models on the demand side of the market mean for power producers.

Demand side - price/revenue models small (retail) and large (industrial) consumers

Figure 4 on the next page shows some examples based on the experiences in other markets discussed in the previous chapter and revenue models that to some extent are already present on the electricity market. It is very likely that figure 4 is not complete and that new business models will develop or are already available in the market. Entrepreneurs will respond to changes in the market and develop new products and services for consumers. Note that new products may also consist of combinations of the features described below.

When we refer to “consumer” we mean both small retail consumers and large industrial consumers, unless stated otherwise. Most revenue models can in principle be applied to small (retail) as well as large (industrial) consumers. In practice the preferences for pricing models of course differ between consumer groups and even between consumers.

Figure 4 – Revenue models on the demand side (contract between supplier and "consumer")

Model	***Description***	***Examples***
Flexible prices	Prices respond to changes in spot market	Industrial consumers electricity market, new proposition by a company that offers retail consumers prices based on wholesale market (+ subscription fee)
Long term contracts with fixed prices	Consumer does not face price risks in this contract.	Broadband, existing contracts in retail electricity market
Tiered pricing	Consumer pays a fixed fee for baseload of electricity but has to pay at certain hours or if consumption exceeds a certain level	Mobile telecommunications (payment plan with data limit), rail roads (season ticket for a specific trajectory)
Bundle of services	Electricity is offered in a package with other services (behind-the-meter electricity services) or other services (telecommunications, water, gas, heat/cold)	Supply contract with energy efficiency advice services, smart thermostat or electric vehicle charging station.
Freemium	Electricity is supplied with other goods	E.g. refrigerator with electricity supply for X years (Tesla, a car manufacturer, offered cars with free charging in the past)
If available	Consumers can only receive electricity when specific production assets produce electricity or they are charged higher prices if there is no production	Some mobile telco plans which limit bandwidth if a contractual limit has been reached.
Managed availability	Consumers provide control to certain appliances and allow supplier to turn them on/off based on price fluctuations	Experiments with demand side management in electricity markets, large industrial consumers (e.g. in balancing markets). Compensation of ESCO based on energy savings.
Pre-paid	Consumers pay upfront for X kWh of electricity consumption	Mobile telecommunications. Retail electricity market in some countries

The discussed revenue models can be differentiated based on the following characteristics:

- Managing of **price risks** – in traditional retail contracts consumers are not fully exposed to price fluctuations on the spot market. For larger consumers it is more common that they manage price risks themselves in dynamic electricity price contracts, in a future market without any technological constraints such a contract might also be preferred by some retail consumers.
- Managing of **volume risks** – In traditional electricity supply contracts consumers pay more if they use more electricity. It is imaginable that this changes, in mobile telecommunications price plans for example consumers pay a fixed (monthly) price until they reach the limit of their data bundle.
- **The time horizon** – The characteristics discussed are offered over a certain period, which could be relatively short (e.g. a month or a year) or longer (e.g. multi-year contracts). The time horizon is related to the allocation of risks between consumers and suppliers.
- **Energy management (managing volume)** – Energy Service Companies (so-called ESCO's) to some extent (depending on the type of contract) are responsible for the volume of electricity consumption. In theory, this could be extended to all consumers, small and large if they have smart meters and smart appliances. Small and large consumers might allow a supplier to control some of their appliances, adjusting consumption to changes in the market.
- **Energy related services and products** – Many suppliers already offer services such as energy efficiency advice, charging stations for electric vehicles etc. Note that energy management services do not fall in this category but are mentioned separately.
- **Other services –** Suppliers can leverage their client relationship to cross-sell other products and services (e.g. telecommunications, home automation etc.)

In principle, there seem no practical barriers to offer one of the revenue models included in figure 1 to either small or large consumers in our scenario of the future electricity market. Information technology has reduced the costs of demand side management technologies and smart meters will make it possible to apply flexible pricing to all consumers groups. However, there will remain differences between preferences of consumer groups and even individual consumers. In practice, suppliers will offer different products to different user groups (as suppliers do in mobile telecommunications) depending on their preferences. Different user groups are targeted with these products based on their willingness to pay; some users will prefer "basic" services, others will prefer additional services (e.g. energy efficiency advice).

For the purposes of this report the main question is if the existing and emerging revenue models will provide fixed or variable revenues to producers. On the consumer side there are both drivers that increase the demand for flexibility (short-term contracts with variable prices) and drivers for an increase in demand for fixed capacity with prices that do not move with spot prices.

- Small and large consumers that have their own production capacity likely need flexibility to respond to changes in their own consumption/production level.

  This group of consumers require contracts that provide flexibility to respond to changes in their production levels. Some consumers in this group might be willing to take price risks, others will prefer that the supplier (or another market party) bears that risk.

- Consumers that are able to shift their electricity consumption over time or store electricity likely prefer a contract for a fixed capacity or a fixed (annual) consumption level if that is economically attractive. Some consumers may also choose long term contracts with fixed prices that do not depend on consumption in order not to be exposed to price fluctuations.

  For this group it can be attractive to buy a “bundle of electricity” (á la telecommunications) or subscribe to a certain level of capacity (á la Netflix). A combination of products to manage energy flows (especially “behind-the-meter services”) may also be attractive. A “baseload” of electricity consumption can be part of such a combination of products and services.

Supply side - revenue model producer

The revenue models discussed in the previous paragraph concern the revenues of a supplier. What do these revenues imply for our renewable producer with a single wind turbine introduced in the introduction of this chapter?

Wholesale market provides a benchmark for investment decisions, regardless of ownership structure

The owner of a renewable production asset does not necessarily sell its electricity in wholesale markets (see figure 5):

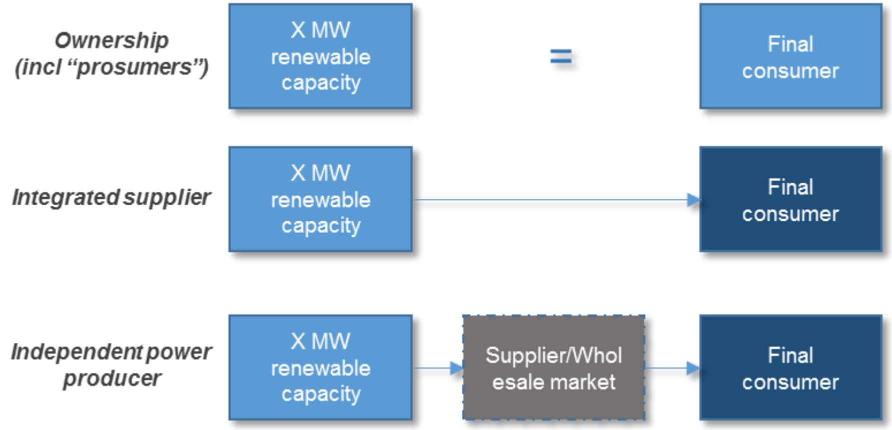
- In the current market and the market of the future a substantial share of all generation assets are owned by consumers. These producers/prosumers only enter wholesale markets when their electricity generation exceeds consumption (and they are not able to store it) or when consumption exceeds generation. If price are high these producers might also choose to sell electricity at the expense of their own consumption.

- Other assets are owned by suppliers who sell - all or most of - their output directly to consumers.

Hence only a fraction (albeit a sizable one) of total electricity consumption is traded in wholesale markets. Prosumers that consume all the electricity they produce are to a limited extent exposed to fluctuations on wholesale markets. The "revenue model" for these market players is that they do not have to buy electricity in the market.

An integrated supplier can transfer both price and volume risks to consumers or third parties or bear some or all of the risks itself. The revenue models that are possible for suppliers are discussed above. However, "prosumers" and integrated suppliers base their investment decisions on the opportunity costs (the costs of obtaining electricity from other sources). Wholesale prices provide a benchmark for those opportunity costs. This means that if wholesale prices are below the long term average costs, these market participants will not invest in their own assets. But when prices exceed long term average costs they will. This is one of the mechanisms that ensure that in the long run prices equal average costs.

Figure 5 – Contractual relationships renewable energy producers



For an independent power producer there are only a limited number of revenue models imaginable (figure 6). Producers are either fully exposed to market forces ("merchant producer") or price (and possibly volume) risks are shifted to suppliers or consumers, by selling in long-term forward markets or by entering a Power Purchase Agreement. In practice most independent power producers will enter into a PPA to limit their market exposure. Such agreements are increasingly used by companies to procure renewable energy.

Additionally, producers might also be able to generate revenues by offering grid support services.[13]

A merchant producer that is fully exposed to price risks will likely have to earn its revenues in a limited number of hours. This means that a merchant producer with only renewables in its portfolio generally faces more risks than a producer with only fossil-fuel plants. A likely implication is that producers or suppliers have an incentive to enlarge and diversify their portfolio to spread price and volume risks. It is also possible that other (financial) intermediaries take over the risks of fluctuations in renewable electricity generation and prices.

Figure 6 – revenue model producer on wholesale market

Model	***Description***
Merchant producer	Revenues based on spot market and short-term forward (wholesale) markets
Power Purchase Agreement (PPA)	All price/volume risks are mitigated in long term contracts (with utilities or corporates)
Price hedge or *synthetic* PPA	Price and volume risks are partly mitigated, revenues depend partly on wholesale spot prices

[13] REservices (2014), "Economic grid support services by wind and solar PV, a review of system needs, technology options, economic benefits and suitable market mechanisms". In a study for TKI wind op Zee, Van Hulle concludes that ancillary services will remain a small source of additional income for offshore wind farm operators, even if massively deployed in favourable power market conditions (Van Hulle, F. (2015), Ancillary services from offshore windfarms in the Netherlands

Revenue model in recent offshore wind tenders

Recently, the Danish wind electricity giant DONG and the German company EnBW both won an offshore wind contract in Germany by not requesting any subsidies. How might the revenue model of DONG and EnBW work? As explained in figure 2 and 3 there are several options:

1. They might expect that they will recover the investment based on wholesale prices.
2. They might have a PPA with a third company, for example a corporate that wants a guaranteed supply of renewable electricity.
3. DONG and EnWB is also a supplier and can supply wind generated by the offshore park to its customers. Note that in this case it will still consider the opportunity costs of doing so, i.e. the investment decision will be based on a projection of wholesale prices.

In press statements DONG and EnBW have expressed that they have based their bids on their projection of wholesale prices and their expectation that cost prices will continue to drop. The tenders do not yet provide conclusive evidence that investments are feasible without subsidies as the companies will take a final investment decision on a later date (the farms are planned for 2025). Developers can back out of a project at relatively low costs which means that it remains to be seen if offshore wind is indeed already competitive in the German market.

Conclusion

The transition to a 100% renewables market has different implications for the revenue model preferred by consumers and producers:

- Producers with renewable assets have a high share of fixed costs and generally prefer a revenue model with fixed revenues and long term contracts as they cannot easily adjust their generation levels to changes in demand and supply. For these producers it is not rational to sell their electricity long term for a price below the levelized costs. Merchant producers that rely on wholesale prices face higher risks and consequently will only invest if they expect prices that allow them to meet a relatively higher target rate of return.

- For small and large (industrial) consumers the picture is mixed. The discussed revenue models differ depending on characteristics such as price risks, volume risks, time horizon, etcetera. Some (probably the majority) consumers will for example prefer fixed prices, others will prefer flexible prices based on spot market developments.

While the preferences of consumers or producers at first sight may not be fully compatible, it is the nature of markets to let supply and demand meet. The different propositions offered to consumers is precisely this mechanism that is at work. The type of revenue model chosen determines whether risks lie with the producer or the consumer. Finally, it should be noted that the revenue models discussed will often go hand-in-hand with the emergence of new market participants or the reinvention of old ones. Many intermediaries are expected to be active on the future energy market. Depending on their risk appetite, these intermediairies will also bear part of the risks. For example, suppliers (not owning generators) have already been active for decades. Aggregators will also increasingly become active, either providing semi-automatic energy management services or by actively managing demand. Some market participants may be especially well positioned to provide flexibility and hence absorb risks (eg. storage, hydro, biomass, demand response). Other (financial) market players are able to offer a hedge to flucations in wholesale prices to porducers or consumers

Thus, in a 100% renewable market there are various revenue models that can result in a profitable business case for an investment in a renewable production asset. That does of course not imply that all investments will be profitable. Ultimately, wholesale prices will remain the relevant benchmark for the opportunity costs of an investment in production capacity. An integrated supplier will for example not invest if he expects that wholesale prices are insufficient to recover investments as it would be cheaper to purchase electricity on the wholesale market. From the perspective of an individual investor his main worry is how demand and supply will develop as that determines future prices – the chosen revenue model is a tool that helps to allocate these risks.

In this chapter we have implicitly assumed that all revenue models are possible and that governments, regulators and TSOs do not interfere. In the next chapter we discuss if there is any rationale for using alternative market models with more intervention in the revenue models applied by suppliers and producers.

Market model

Role of competitive markets and rules set by governments and regulators

Introduction alternative market models

In this chapter we evaluate what kind of market model is able to deliver incentives to invest in renewable energy and guarantees a high level of security of supply. This model must be able to accommodate the needs of producers and consumers as well as intermediaries and integrated energy suppliers. Ideally, it should not have any of the "market failures" mentioned in the previous chapters.

Market models considered

We consider three "categories" of market models. Within each category there are many different models possible.

- Model 1: central planning and control of the system ("single buyer");
- Model 2: a market with centralized rules regarding the specific pricing structure to be used in wholesale and retail markets in addition to the 'energy-only market';
- Model 3: a market in which producers and consumers have freedom to use their preferred pricing structure (often referred to as an 'energy-only market'[14]).

Note that we do not focus on elements of market models that are aimed at specific technologies such as "Contract for Differences" (DfD), Feed-in premiums, obligations to supply a certain share of total supplies with renewable energy etc. In our analysis we assume that renewables are already the norm, in such a scenario there is no need to have specific regulation aimed at renewables (other than a ban on fossil fuel electricity generation or sufficiently high CO_2 prices as explained in our Scenario).

Model 1. Central "planning and control" of the system

In the current market there is already a significant role for government intervention. A large share of investments in renewables is not primarily based on market signals but on government subsidies. In theory, this could be taken further and extended to the whole market. In the most extreme version the government or system operator takes control of the entire system: "central planning". Market forces can be introduced in this model when a "single buyer" contracts electricity generation

[14] In the remainder of this report we do not use this term as it suggests that there are only transactions based on a certain volume of electricity. Freedom to use different kinds of pricing structures means that pricing structures not based on energy (MWh) may play an important role, but not as the result of government intervention. For example, prices may be based on capacity (MW).

from private players which would be remunerated based on the levelized cost of energy (LCOE). Such a model could in principle solve a number of the perceived market failures of the current system: the government can ensure all needed capacity is put in place, and can ensure this capacity is adequately funded. Perceived regulatory risks might also be lower in such a model.

We will not discuss central planning and control of the system in detail as it conflicts with one of the requirements that the market model should be market based. The main problem is that in such a system it is much more complex to balance supply and demand. In a market with a few fossil-fuel producers and stable demand it is relatively straightforward to determine what the generation volumes should be. In today's market, and even more so in the future, there are numerous generators. Moreover, large and small consumers have the ability to adjust their consumption. For a central entity it is nearly impossible to efficiently contract adequate levels of generation and demand response, especially in a complex future world with numerous and constantly evolving central and decentral generation assets, storage and demand response. The reliance on the decisions of a single decision-maker increases the risk that this single decision-maker takes the wrong decisions. Using demand response flexibility in the system in combination with decentralized generation and storage would be very complicated as the actions of many different actors have to be coordinated.

IEA (2016) summarizes why wholesale energy markets have an essential function that can not be replicated through a centralized system. (Wholesale) energy markets can:

- Ensure co-ordination of millions of distributed resources locally (including demand response and storage) and co-ordination across large geographic areas spanning multiple control areas.
- Provide incentives to perform, i.e. minimise operation costs and be available when the system values the resources most.
- Bring transparency and inform collective decisions about the relative value to the system of different resources and in particular renewable generation technologies.
- Incentivise innovation in the power system.

Model 1 would not benefit from these advantages of markets.

Model 2. Centralized rules prescribing the pricing structure

In the previous chapters we concluded that it is likely that producers and consumers prefer a different pricing structure if the cost structure changes or if new technologies such as storage are introduced. Based on this observation alternative market models have been proposed which emphasize a specific pricing structure or revenue model in addition to the 'energy-only model'. Below we discuss a number of those proposals.

2.A. The two-market solution

Keay (2016) introduces the idea of splitting wholesale and renewable markets in two separate markets.[15] One would be 'as available' power, which is available to consumers at a relatively low price at times when there is sufficient supply in the corresponding wholesale market for participating low-carbon generators. The other would be 'on demand' power, available at all times but at a significantly higher price. The idea is that the differing costs and operation of 'as available' and 'on demand' sources are reflected in the retail market. Consumers are able to select 'on demand' or 'as available' power (with separate meter readings) or also combinations of the two sources. This system is supposed to ensure that all generators (renewables and conventional) are remunerated by the market by providing appropriate investment signals – solving a perceived market failure of the current system.

Consumers would receive the 'as available' price as long as generation of that class exceeded demand. This would require that consumers have appliances capable of reacting to the presence of 'as available' supply and designed to make best use of it. In Keay's proposal consumers that do not have such equipment would pay the more expensive 'on demand price' which includes the system costs of reliability and flexibility.

According to Keay, wholesale markets could be constructed along the same lines. Generators would have the choice of entering either the 'on demand' (or flexibility) market, or being dispatched in the 'as available' pool. Dispatch in the 'as available' segment would be automatic. Prices in the 'as available' part of the wholesale market could be set in various ways. They could initially be set by government or regulator on the basis of the expected long term marginal cost of capacity in this segment of the market, but with additional support offered to producers as needed to ensure that their total investment costs were covered (i.e. subsidies for renewables). In the long term, the prices established in this market by consumer demand would determine the volume of inflexible plants. Over time, consumers' ability to use 'on demand' power would increase and its value in the market should become apparent.

15 Keay, M., 'Electricity markets are broken—can they be fixed?', OIES Paper: EL 17, The Oxford Institute for Energy Studies, 2016, 1-38

Prices in the flexible market prices could involve flexible and capacity payments. At the wholesale level prices would have to cover the costs of generators. These costs together with system costs would be passed on to consumers.

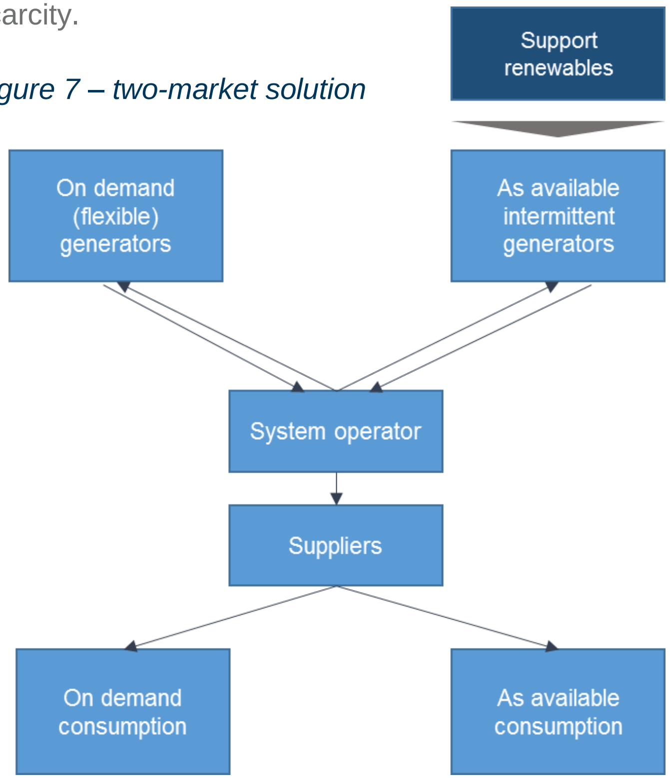
If the cost of renewables falls, the cost of generation for the 'as available' market should increasingly tend towards the value of such supply for consumers and support for renewables can be phased out.

This two-market solution has similarities to proposals for capacity markets (see 2.D.). An advantage of the model would be that consumers consider the price of scarcity in their consumption decisions which may contribute to security of supply. However, large consumers and increasingly small (retail) consumers already can respond to changes in market prices. A single price for 'as available' power is likely to be inefficient as the willingness to pay for electricity differs between consumers. If the reform would only be aimed at retail consumers it seems unlikely that it will have a significant on the market as retail consumers are just a share of the total market and many consumers will not be willing to adjust their consumption.

Another disadvantage is that it would require an overhaul of retail and wholesale markets, the added complexity would entail costs. All consumer devices would have to be modified to be switched of if 'as available' electricity is not available. Although a transition to a two-market model would add complexity the model is flexible once implemented, consumers and producers do not face any restrictions.

If small and large consumers have smart meters a similar market outcome could be reached if suppliers charge higher prices in times of scarcity (consumers pay a higher prices for electricity if 'as available' supply is not available). For this reasons the two-market solutions is likely less efficient than a market in which prices reflect the costs to the system in times of scarcity.

Figure 7 – two-market solution



Explanation figure 5 by Keay (2016)
"On demand" (flexible) generators are dispatched by the system operator and receive income form the market, which could include capacity, energy and other payments. "As available" generators power output is accepted automatically by the system operator. They receive the (relatively low) "as available" price set, initially by the government or regulator, in the long run by demand in the "as available" market. In the transition period they also receive income from market support schemes for renewable and low carbon sources. Depending on the regulatory system, suppliers could either choose to purchase separate on demand and as available supply and thus take advantage of the two generation price options, and to be able to offer consumers a choice, or could be required to offer the two options to consumers.

2.B. (Mandatory) lump-sum fixed prices for electricity supply (not dependent on volume supplied)

When the fixed costs of electricity production increase and variable costs decrease producers will generally prefer a larger share of fixed lump-sum revenues as they cannot adjust output. With fully variable revenues price and volume risks for producers (or intermediaries) would increase and producers would request a higher financial rate of return.

A solution to this may be to mandate that suppliers charge each small and large consumer a fixed lump-sum rate. In our view there are merits in this proposal as it could provide more certainty for producers that investments will be remunerated.

Producers would be less dependent on uncertain price developments in wholesale markets. This could lower capital costs and increase investments in capacity with positive effects on security of supply. Hence, such a model could potentially address perceived market failures of the current market.

A drawback of this model is that a fixed distribution between fixed and variable prices would result in less flexibility and add complexity. If the allocation between fixed and variable prices does not match with the underlying cost structure it may also result in inefficiencies. If variable prices are very low there is for example the risk of over-consumption. If variable prices are set too high there is less consumption than would be socially optimal and some consumers may have the incentive to go off-grid.

The preference for fixed lump-sum versus variable prices differs between consumers. Consumers that have their own production assets will likely prefer more variable prices as they only take electricity from the grid in certain conditions. Consumers that are able to shift their electricity consumption over time or store electricity likely prefer a contract for a fixed capacity or a fixed (annual) consumption level if that is economically attractive. The differences in preferences between consumers implies that it will be difficult if not impossible to set rates at the "right" level.

2.C. Long term contracts (Investment markets)

The main feature of this model is that it shifts competition in the market (spot market) to competition *for* the market. Suppliers are required to cover their forecasted demand through contracts with generators and flexible solution providers. In exchange, generators receive long-term contracts with conditions and terms allowing them to recover the total costs of their investments. The short-term market in this context acts as a balancing market to settle imbalances arising from contractual differences between generators and suppliers (EC, 2015).[16] A number of South American countries (Chili, Peru, Brazil) have a model with central auctions for long-term contracts which is comparable to this model. Long-term contracts are also used to support nuclear power generation, for example the nuclear plant at Hinkley Point C in the UK.

This model aims to solve perceived market failures in the current energy-only market by providing long term stability to investors and producers. Many providers of renewable capacity prefer long term contracts as it limits their exposure to price risk, a price that they cannot manage themselves as they cannot (or only to a limited extent – depending on technological developments) adjust output if market prices change. Such long term contracts might encourage additional investments in capacity which could contribute to security of supply. A drawback is that *someone* has to decide what share of supply needs to be covered by long-term contracts and how long those contracts should be. This results in complexity and makes it difficult to adapt the model to changes in the market. There is a considerable risk that too much or too few capacity is contracted, resulting in inefficiencies in the system. Long term contracts could also distort incentives to invest in demand response and storage as they have less opportunities to benefit from short-term price fluctuations. Lastly, if too much energy is contracted long term the markets is foreclosed. New entrants will not be able to enter the market as consumers have already contracted their required capacity.[17] The risk that markets are not open for new entrants can be partly mitigated by auctioning separate contracts for new and existing contracts (as Brazil does).

2.D. Capacity markets

Capacity markets provide a remuneration for having generation capacity available. In recent years there has been a lot of discussion around capacity markets and many different models have been proposed, some of them have been implemented in a number of European countries (in a sector enquiry the European Commission found 35 mechanisms in 11 countries). The most common mechanisms are “strategic reserves”,

16 European Commission (2015), “Energy economic developments, investment perspectives in electricity markets”, Institutional Paper 003

17 See also E-Bridge Consulting, UMS Group and Prof. W.A. Wolak (2013), “White Paper zu einem nachhaltigen Strommarktdesign”

"tenders for new capacity" and "targeted capacity payments schemes".[18] The main idea behind all these models is that generators do not only receive compensation for electricity that is actually produced but also for supplying (fixed) capacity to the market.

Capacity mechanisms are suggested to address perceived market failures that are deemed to prevent timely investments in generation capacity. The EC's sector enquiry cites a limited ability of electricity markets to deliver high prices at times of scarcity as they key market failure, which is due to a number of reasons:

- Few individual electricity customers are able to respond to price variations in real time and to reduce their consumption during peak hours when prices are high. To protect consumers, price caps have been put in place that are relatively low and do not reflect customers' willingness to pay for secure supply.
- The rules for managing balancing markets, where electricity generation and demand must be matched in real time by network operators and the ultimate electricity price for each hour is set, in practice cap the price in forward markets.
- Bidding zones are often delineated in such a way that out-of-market 'redispatching' measures are required to turn off some generation and turn it on elsewhere (at extra cost) within a zone to balance the grid. This out-of-market redispatching undermines investment signals and distorts electricity prices.
- Even where scarcity pricing is allowed, and bidding zones are appropriately delineated, market participants may still be hesitant to invest in new capacity due to considerable uncertainty about future market developments, such as the impact on their investment of the increasing market share of renewable energy and potentially extreme price volatility.

In this report we do not provide a detailed discussion of all the merits and drawbacks of capacity markets. However, we note that in practice it is difficult to design a mechanism, it is very complex for example to treat all forms of electricity production and demand response equally. Moreover, it is costly to enforce rules regarding the mechanism, to adapt the mechanism to changes in market circumstances and technological developments and to prevent market distortions.

In our view it is generally optimal to put a price on scarcity (based on the value of lost load). High prices at times of scarcity provide suppliers/consumers an incentive to contract capacity to avoid having to buy in the spot market in situations when prices are high. Although capacity markets may have merits in specific situations they do not provide a silver bullet

18 European Commission (2016), "Final Report of the Sector Inquiry on Capacity Mechanisms", COM(2016) 752 final

solution that ensures sufficient incentives to invest in generation capacity. Moreover, when capacity mechanisms are poorly designed there is a risk of inefficiencies, too much capacity may be contracted for example or there is no level playing field between generation options (including small prosumers and demand response) which results in too much or too few of some generation options.

Conclusions regarding "Model 2"

In table 2 we have scored the models relatively to the current market model. The table shows that these models in theory can contribute to the security of supply. Whether they do so in practice depends on the details of the market design as well as its implementation. For example, an inadequately organized market with long term contracts might also result in lower reliability. Another example is a capacity mechanism that rewards producers that would be also in the market in the absence of capacity payments does not contribute to security of supply – hence the details of the capacity market design are very important.

Although the models may result in higher reliability, this comes at a cost. All models result in less efficiency and flexibility and diminished incentives for innovation. All models add complexity to the market, in model B for example someone has to determine the optimal maturity of contracts. In model A markets have to be administratively split in two.
In model B and C there is less flexibility to choose a preferred contractual structure, e.g. with a mandatory fixed payment for electricity supply. Consumers that prefer flexible prices might not be able to select the contract that they prefer.

	A. Splitting up market in firm/interruptible	B. Change share of fixed/variable prices	C. Long term contracts	D. Capacity remuneration mechanism
Efficiency (lowest societal costs)	-	-	-	-
Flexibility (can model be adjusted to changes in market)	=	-	-	=
Incentives security of supply	+	+/-	+/-	+/-
Complexity	-	=	-	-

Table 2 – Advantages and disadvantages of "model 2"

- (somewhat) worse than current market model

= similar to current market model

+/- either (somewhat) better or worse than current market model

+ better than current market model

Model 3. A market in which producers and consumers have freedom to use their preferred revenue model

In chapter four we discussed experiences in other sectors. In markets with no or limited regulations regarding pricing there are generally a variety of revenue models. Model 3 reflects this and leaves it to producers, suppliers and consumers to use their preferred pricing or revenue model.

The pricing structure that results from the competitive process may well resemble in some ways one of the pricing structures discussed under "Model 2". Producers are not necessarily paid based on the megawatt hours produced in this model. It is likely that some producers will sell all of their capacity directly to consumers or to intermediaries. Other producers will also be active on the market as consumers. "Model 3" offers the perspective to benefit from the advantages of the alternatives discussed under "Model 2" without the disadvantages as there is less complexity and more flexibility for all market participants. The risk that consumption and investments decisions are distorted in an inefficient way is also lower.

In many ways this model is an evolution from the current model rather than a revolutionary change.

Our conclusion that the scenario with only renewables requires not a fundamentally different market model but that there are market distortions that can be addressed is in line with for example the conclusions of a report of IEA on market design and regulation during the transition to low-carbon power systems[19], a report of the MIT energy initiative on the "Utility of the Future" [20] and a report by the International Renewable Energy Agency. [21]

"The transition to low-carbon power can be carried out through upgrades to existing market arrangements and regulatory instruments. The necessary upgrades can be identified in the best practices of existing electricity markets in Europe, the Australian National Electricity Market and North America.

In the longer run, the design of markets will be shaped by technologies such as storage, demand response and consumers installing distributed resources. But this is not yet the case and, for the time being, market design requires no shift in paradigm. Keeping this in mind, the transition phase is likely to be an evolutionary process based on the interactions between technologies and market rules.'

IEA, Re-powering markets

19 IEA (2016), "Re-powering markets, market design and regulation during the transition to low-carbon power systems"

20 MIT Energy Initiative (2016), "Utility of the future"

21 IRENA (2017), "Adapting market design to high shares of variable renewable energy", International Renewable Energy Agency, Abu Dhabi

'The presence of high shares of variable renewable energy increases the uncertainty in the prediction of market conditions and network constraints. Consequently, the time and locational granularity of market signals should be increased with rise in variable renewable energy levels. The design of short-term energy markets should be enhanced and refined at all levels, including timelines, bidding formats, clearing and pricing rules, and their integration with reserves and regulation markets.'
Irena, Adapting market design to high shares of variabel renewable energy

'Recommendation 1: Create a comprehensive and cost-reflective system of prices and charges. The only way to enable centralized and distributed resources to jointly and efficiently operate, expand, compete, and collaborate, is to establish a comprehensive and cost-reflective system of economic signals—prices and regulated charges—with adequate granularity in service type, time, and location. Prices and regulated charges collectively determine, at each connection point and time, the value of the services provided or consumed by any particular agent. Incorrect economic signals can drive inefficient investment and operational decisions, enable costlier resources to displace more efficient ones, enable inefficient business models to crowd out efficient ones, and result in more expensive electricity services and a loss of societal welfare.'
MIT, Utility of the future

In table 3 we have listed the differences between "Model 3" and the current model which we explain in more detail below for each of the objectives. In this report we have largely ignored network regulation. Networks are a crucial part of the electricity market and we close this chapter with a brief discussion of the implications of model 3 for network regulation.

Table 3 – Differences between current model and model 3

Policy	"Model 3"	Current model
Support schemes low carbon investment	*Not needed due to regulation or carbon pricing preventing generation based on fossil fuels*	*Level of support unpredictable*
Electricity (wholesale) market regulation	*Energy prices with a high temporal (and possibly also high geographical[22]) resolution. Scarcity pricing*	*Scarcity not fully priced. (Perceived) risk of intervention by regulators. Limited temporal/geographical resolution in energy trading*
Price/tariff regulation small and large consumers	*Full flexibility (taxes and levies should not be too distortionary)*	*Distortions due to taxes and levies*

1. Support schemes low carbon investment

In the current market interventions by governments can distort investment incentives. In the scenario with 100% renewables this is likely less of a concern. If governments intervene at all it should be as transparent and predictable as possible.

2. Electricity (wholesale) market regulation

Key here is to take away distortions due to the missing markets and missing money problem. For retailers and producers this would mean that there are no legal or technological barriers to charge a certain price (without abusing a dominant position). In times of scarcity (when a strategic reserve is activated or in case of load shedding), prices should reflect the "value of lost load" (VoLL). The VoLL should reflect the opportunity costs of the load reduction or the activation of the strategic reserve. At times of scarcity the price of electricity consumption is not based on demand and supply in wholesale and balancing markets but on a level set by the TSO or regulator (based on an assessment of the value of loss load).[23]

In the 100% renewables market more flexibility likely is needed. Ideally, price signals would be varying close to real time. This way prices as closely as possible reflect demand and supply

[22] Some authors stress the need for locational pricing signals (due to constraints in distribution or transmission grid cost level differs between locations).

[23] Alternatively, wholesale prices could be adjusted based on the level of operating reserves. The Electric Reliability Council of Texas (ERCOT) applies for example an "Operating Reserve Demand Curve" (ORDC), in the Texas market a surcharge ("price adder") has to be paid that increase automatically as available operating reserves decrease. When operating reserves drop to 2,000 MW or less, the ORDC will automatically adjust energy prices to the established VoLL.

conditions in the market. To date, market designs vary in their granularity with the closest to real time having five minute settlement periods (Australia). In the future advances in ICT may make it possible to increase the granularity (Newbery, 2017).[24] Increasing penetration of renewables may also require a change in bidding formats and trading algorithms. A detailed analysis of the required changes is beyond the scope of this report. Irena (2017) argues for example that bidding formats should allow market participants to hedge against variable short-term market conditions and to better represent the characteristics of demand response and storage.[25] Van der Welle (2016) argues that there may be benefits of replacing block bids by 'advanced block bids' or 'multi-part bids'.[26]

In "model 3" there are multiple ways in which electricity and electricity generation capacity is traded. To some extent, this is already the case in the current market. Trading in electricity is most transparent at exchanges, where electricity is traded based on standardized contracts. Bilateral trading between market players is less transparent. The transactions of large parties already have to be reported based on REMIT legislation but this is not the case for transactions of smaller consumers and producers. New technologies such as "Blockchain" allow for decentralised tracking of contracts. Blockchain systems are fully decentralised, with all transactions being arranged, executed and performed on a peer-to-peer basis. Such technologies may offer a cost-effective way to obtain insight into available generation capacity, storage capacity and supply contracts, including details such as the duration of the contract and conditions (e.g. guaranteed supply or supply-if-available). The benefits of such a system with a decentral register have of course to be weighed against the costs. A possible benefit is that transmission operators have better information to project adequacy of supply. The costs consists of the administrative burden to producers and the cost of developing and maintaining the system.

In chapter 5 ("Revenue models") we concluded that it is likely that the risks for suppliers/intermediaries increase as the cost structure will be largely fixed but demand may fluctuate. This might be a reason to put more emphasis on the oversight of risk management practices of electricity market participants. The main goal of this oversight would be to ensure that market participants have adequate risk management systems and procedures. Requirements regarding minimal solvency and liquidity rates might be possible additional measures. There are obvious parallels with the regulatory framework as applied in banking and insurance markets. E-Bridge (2014) refers to this

24 Newbery, D. (2017) "What future(s) for liberalized electricity markets: efficient, equitable or innovative?", Energy Policy Research Group Working Paper.

25 IRENA (2017), "Adapting market design to high shares of variable renewable energy", International Renewable Energy Agency, Abu Dhabi

26 Van der Welle, A. (2016), "Required adjustments of electricity market design for a more flexible energy system in the short term" (ECN-N-16-033)

idea as a "risk-based safety net".[27] The main attraction of such a safety net is that it comes with relatively limited market distortions if implemented correctly.

Cross-border trade can reduce the costs of the system and contribute to security of supply in our scenario with 100% renewables. In our scenario with only renewable electricity the benefits of interconnection are higher than in a market dominated by fossil-fuels due to the intermittency of wind and solar energy.[28] The benefits of interconnection are higher the larger the differences between countries in generation mix, weather conditions and endowment with storage options. Over the last decades cross-border capacity has increased. There are still opportunities to improve the working of the (intra-day) market. Ultimately, electricity should be able to flow at any moment to where the value is highest.

3. Prices/tariffs retail market

Consumer should be able to select the pricing plan that they prefer. Some consumers will choose a long term contract with fixed lump-sum rates. Other consumers will be very active on the market and responsive to price changes.

Taxes should be designed in such a way that they do not distort decisions of producers and consumers (although taxes may need to be distortive to reach other policy goals). Net metering is often mentioned as an example of how taxes can distort incentives. Due to net metering households pay less taxes on their electricity consumption which makes investments in for example solar panels more attractive. In the long run such distortions can result in too much or inefficient investments in capacity. High energy taxes can also distort incentives to invest in storage as storage may be used to limit taxes to be paid by small and large prosumers. As a result there may be too much storage that is not necessarily located in parts of the electricity network where it is most needed. When electricity is stored by an independent operator there is the possibility of double taxation (when the storage is loaded and when electricity is consumed). This can obviously reduce the incentive to invest in storage. Differences in tax rates between electricity and gas may also have an impact on incentives to invest in Power-to-gas technologies.

In many markets taxes form a high share of the total electricity bill. It is likely that this can make some pricing models (e.g. a bundle of electricity for a fixed lump-sum price) less attractive than they would be in absence of the taxes. Due to the high share of taxes, the relative effect of using the bundle is lower

[27] E-Bridge (2014), "Ein Beitrag zur Ausgestaltung eines Fangnetzes zur nachhaltigen Gewährleistung der Versorgungssicherheit"

[28] Newbery, D. et al (2017), "Market design for a high-renewables European electricity system", Cambridge Working Paper Economics: 1726

than it would be without the taxes. Similarly, a proposition like ‘free electricity in weekends’ (offered by for example Direct Energy in the US) when demand is low is likely to be less attractive when taxes and network charges form the largest share of an electricity bill.

In sum, tax distortions are often mentioned in the context of net metering but there are other reasons why the current tax framework should be reconsidered in our scenario with 100% renewables.

Regulation of network operators

Limited capacity of distribution and transmission networks can be a constraint that distorts demand and supply decisions in the market. When there is abundant capacity, markets are not distorted but system costs may be high. This means that there should be appropriate incentives for network owners to invest while taking into consideration cost efficiency.

This report is focused on how renewable electricity producers should be remunerated in a 100% renewables market. We have not studied in detail what changes are needed in for example network tariffs. In general, transmission and distribution tariffs should not discriminate between types of production/consumption, consumers and producers should not choose production over storage or demand response just because of network tariffs, unless there are differences in the costs that the additional production or consumption cause in the network. Network charges based on capacity are in general less distortive than charges based on electricity consumption.

Compared to wholesale markets, network tariffs are static. In many countries there is a tariff that is equal in all locations and adjusted infrequently (often yearly). But the value and cost of electricity can vary significantly at different times and locations. This may provide an argument for increasing the temporal and locational granularity of prices and charges (for example nodal pricing or pricing including locational signals (IRENA, 2017)) but such measures have to be balanced against the costs, including complexity while their effectiveness also needs to be further researched.[29]

Conclusions regarding “Model 3”

Model 3 offers the perspective of a flexible, efficient market with security of supply. Contrary to “model 1” and “model 2” there is not necessarily a trade-off between security of supply and other objectives.

[29] MIT Energy Initiative (2016), “Utility of the future”

Within model 3 there is scope to address market failures and to improve the functioning of the price mechanism. Below we have included a number of measures that can be considered:

- When demand exceeds supply prices should be able to reflect the *value of lost load.* Ideally, energy prices should have a high temporal (and possibly also high geographical) granularity with trading very close to real-time;
- Governments should either not interfere in the market or be very predictable, taxes and network charges should not be excessively distortive (taxes and network charges should not distort level playing field between technologies, including storage and demand response);
- In a market with only renewables the benefits of interconnection are high, especially when other countries have more storage capacity. Measures to take away barriers that limit energy flows from one country to a country where it is more needed such as investments in additional capacity and improving (intraday) markets should be taken.

Transition

Market model in transition towards 100% renewables

During the energy transition more distortions of incentives to invest

In this report we have used a scenario with only renewable electricity production. For this scenario to be realised a transition from today's still modest contribution of renewables is required. In the previous chapter we concluded that "model 3" with flexibility for market players is the optimal model *in* the scenario with 100% renewables. Is this model also equipped to deal with the challenges of the transition *towards* a market without fossil fuels?

The main driver for investments in electricity generation during the transition are government subsidies as market prices alone provide insufficient incentives to invest in renewables. It seems unlikely that this situation will change in the near future, although it can for certain technologies and certain locations. Uncertainty about subsidy levels, CO_2-prices and trading mechanisms and the phasing out particular technologies (e.g. coal and nuclear), can form a regulatory risk that distorts investment decisions. For investors it is difficult to predict how supply and demand in the medium and long term will develop as it depends on actions taken by governments. In the scenario with only renewables this market failure is likely to be reduced, it is hard to see a justification for additional interventions in the market in this scenario.

Rationale for intervention is clearer in a market in transition

So there are reasons to expect that the risks of market failure and missing markets are higher during the transition than after the transition has been completed. Moreover, during the transition there is a risk that fossil fuel generators leave the market while there are still insufficient other suppliers of flexibility (storage, demand response). This implies that the rationale for market interventions is clearer in a market in transition than in a market that has already transitioned.

Thus, arguments to introduce a capacity mechanism, a strategic reserve or a "safety net" that address market failures are stronger during the transition than after the transition has been completed. Indeed, in the literature and public debate such measures are discussed and have been implemented in many European Member States.

However, this does not automatically imply that such interventions aimed at maintaining security of supply are indeed needed. We have not analysed this as this was not the focus of our report. Whether such interventions are desirable should in any case be thoroughly assessed, also the costs and benefits, and when implemented they should be designed with care.

In this report we note that the potential benefits of such interventions (capacity mechanisms or mandatory long term contracts) in a market with only renewables are likely to be lower than they are today. So, if the benefits would be considered lower than the cost today it is unlikely that this conclusion would change in a market with only renewables.

The other conclusions regarding “model 3” are also applicable in a market in which fossil fuels are still dominant. In that sense measures to improve the functioning of the market mechanism and address market failures can be considered “no-regret options”. For example, implicit or explicit price caps are as undesirable in the scenario with only renewables as they are in today’s market. Likewise, distortions due to taxation should be avoided as much as possible in all scenarios.

Conclusion

In a fully renewable energy market there will be more power generation facilities with low marginal costs. The volume of electricity generation and prices will become more volatile as a result of the intermittency of wind and sun.

These developments have already started and resulted in new business and revenue models offered to consumers (both retail and large users). It is likely that in the future new models will emerge. These revenue models provide the revenues for profitable business cases in generation assets. Although it can be expected that there will be more emphasis on fixed lump sum prices for access to electricity supply, it is impossible to predict what kind of revenue models will become dominant. Experiences in other markets show that there *are* incentives to invest in production assets in such a market, just as basic economic theory predicts. We conclude that we expect a 100% renewables market to provide adequate investment incentives even without government subsidies.

The price mechanism is the best way to balance demand and supply in a market with millions of actors. For a single buyer it would be extremely complex to calculate required dispatch in a world of decentralised production, demand response and abundant storage possibilities.

We do not propose any specific regulatory change that would force or stimulate market participants to use a specific revenue model or contractual structure (e.g. mandatory use of long-term contracts or obligation that capacity has to be contracted in addition to what some call the 'energy-only' market). There are risks that any such regulatory change would result in less efficiency, less flexibility and diminished incentives to innovate. Moreover, developments in the market such as increased opportunities for demand response and storage may be hampered if the pricing structure is poorly designed.

Our conclusions do not only apply to our scenario with 100% renewables and substantial demand response and storage options but also in the transition towards a market with 100% renewables. This does not rule out any interventions (e.g. capacity mechanisms or other interventions) during the transition phase towards a fully renewable market. However, arguments for market interventions in a renewables-only market are less convincing than during the transition. We have not analysed the costs and benefits of any such interventions in this report.

Based on our analysis the optimal strategy is to improve the functioning of the price mechanism. Below we have included a number of measures that can be considered:

- When demand exceeds supply, prices should be able to reflect the *value of lost load.* Ideally, energy prices should have a high temporal (and possibly also high geographical) granularity with trading very close to real-time. Trading rules

and algorithms used in centralised energy markets should be evaluated to see if they are still fit for purpose in a market with much more price and volume fluctuations;
- Governments should either not interfere in the market or be very predictable, taxes and network charges should not be excessively distortive (some distortion is unavoidable but taxes and network charges should not distort the level playing field between technologies, including storage and demand response);
- In a market with only renewables the benefits of interconnection are high, especially when other countries have more storage (or flexible) capacity. Measures to take away barriers that limit energy flows from one country to where it is more needed – such as investments interconnection capacity and improving (intraday) markets – should be assessed.

These policy recommendations are also applicable in a market that is still transitioning. In that sense they can be considered no-regret options.