Long Term Power Purchase Agreements: the factors that influence contract design

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Patrick Wallace

Patrick Wallace is a partner in Simmons & Simmons LLP and a Visiting Professor of law at King’s College London.

Summary

Power purchase agreements (“PPAs”) are used in a wide range of transactions that facilitate many major objectives of government policy in fostering economic development, reducing prices by introducing competition, and preserving security of supply and protection against intermittent renewable generation by maintaining diversity of fuel types in the generation mix. The purpose a PPA is intended to serve will influence key features of its commercial and legal terms in different ways. The design of PPAs is also influenced by the particular characteristics of electricity as a product and the commercial operational and legal structures of the markets within which the PPAs operate. This paper analyses how these factors influence the price and other terms that tend to be used by independent power generation projects in developed and emerging markets across the world. It then examines the main issues that have to be negotiated in a PPAs to protect each of the parties against the risks presented by the nature of the asset and of the relevant power market.

Introduction

Long term power purchase agreements, widely known as “PPAs”, are a major feature of electricity markets in developed and developing countries across the world and have considerable global economic and developmental significance. They are among the highest value long-term contracts seen in international markets, because of the large capital costs of building the power stations and the value of the fuel that they process over the contract life. They are used to play a major role in trying to strengthen the economies of the countries that deploy them. PPAs are an important vehicle for attracting private sector capital and debt finance from commercial banks and from public sector development finance institutions and export credit agencies to develop new generating capacity to provide the power needed for industrial and commercial development. This is a particular feature of their use in developing countries, where they often also help to make electricity available to large sections of the population for the first time.

PPAs are also one of the legal mechanisms that are used to introduce greater competition into newly created electricity markets. These markets are established when vertically integrated electricity monopolies, which are often state owned, are split into separate generation, transmission, distribution and supply businesses which are generally then privatised. This full liberalisation is more common in developed economies. In these deregulated power markets, competition is introduced to generation by the development of independent generators; and these generators sell power to suppliers and traders under long term power purchase agreements and in wholesale spot markets for short term power trading. Often, competition is also introduced for the supply of electricity at retail level to industrial, commercial and in due course individual consumers.

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1 Such as the IFC, the EBRD and the African Development Bank.

2 In some systems major industrial commercial and public-sector consumers are also able to buy power directly in the wholesale market.
PPAs are also a major part of the legal framework used in implementing government policy on environmental protection and on fostering security of supply through diversity of generation and fuel sources. This normally involves a legislative or regulatory obligation on electricity suppliers to purchase specified amounts of power from renewable or nuclear sources, either by direct contracting or through a competitive auction process, often involving an explicit or implicit cross subsidy. This process results in renewable generators obtaining PPAs with major suppliers who in turn incorporate the renewable electricity produced into the mix of power that is used to supply consumers.

This chapter analyses how these objectives, and the legal structure and commercial risk allocation that apply to the markets that PPAs operate within, influence the way in which the key commercial provisions of PPAs are designed. The chapter begins by reviewing how the distinctive characteristics of electricity as a product and of the power markets PPAs operate influence the overall structure of PPAs. Then the chapter examines the way these features are usually reflected in key clauses in the most commonly used type of PPA, namely the emerging market long term PPA.

1. **The influence of the physical and legal characteristics of electricity**

PPAs are heavily influenced by the distinctive physical and legal nature of electricity. Electricity is, of course, an extremely important product and commodity that is regularly bought and sold in large quantities. However, the important point for contract design is that electricity is not a physical object. Instead, it is a flow of electrons across wires that link a generation station that is producing electricity to a consumer who is using it. Electricity is also a fungible product. It is not possible to trace a specific flow of identifiable electrons from one place to another. A quantity of energy is simply put in to the network at one point and a corresponding quantity is withdrawn by the consumer at an exit point. This has a number of significant legal consequences, as explained below.

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3 This chapter concentrates on the key payment and performance obligations that apply during the operational period of the PPA and on its expiry and on the way the PPA treats major adverse events such as events of political or ordinary force majeure, changes in law and tax and early termination. This focus has been adopted because these clauses show most clearly how product and market characteristics have affected contract design. Many long term PPAs also contain important and detailed clauses governing the process of developing constructing and commissioning the power station as well as complex technical and operational provisions, but these are outside the scope of this analysis.


5 A certain volume of transmission losses is incurred across the system. This is calculated and charged to all users as a system cost, pro rata to amounts transmitted for them.
Because electricity is not a physical object, it is not visible, does not occupy a single location, and cannot easily be defined by a simple description of its physical characteristics. This means that many of the traditional legal rules that would automatically apply to a conventional sale of goods transaction are not very easy to apply to a sale of electricity – so much so that, at least in English law, there is considerable doubt about whether electricity falls within the definition of goods at all. The result is that power purchase agreements must go to great lengths to define the product and its technical characteristics, the obligation to produce it, how it is measured, the obligation to pay for it and what happens when things go wrong. This means asking all the usual questions that would arise on a sale of goods transaction and then addressing them expressly and in a way that suits the specific context in which electricity is sold.

Electricity, by its nature, can only exist in the context of electricity systems that are normally owned by other people because, as stated above, the electricity has to flow along wires which are usually owned by more than one entity. Power will only flow if the operator of the power transmission network, the supply company that buys the power and the consumer who uses it, take the necessary actions that result in the power station being called on to generate and enable the electrons to flow out of the generating station. The power purchase agreement therefore presupposes that these operational steps occur and so the generator needs to know that the PPA recognizes its need to be connected up to the power system and that the generator’s interests are protected if the other steps in the process do not take place. Thus, PPAs have to sit within and be compatible with the broader matrix of legal and operational documents that govern the routine operation of the relevant power system.

2. **A product that has to be produced in real time and that has a very volatile market value**

From a commercial and legal perspective, the most important differentiating characteristic of electricity is, however, the inherent volatility in its economic value and this is what has the strongest influence over the way in which long term PPAs are normally designed. This volatility is caused by the fact that, as a product, electricity is impermanent, cannot really be stored using current technology and therefore has to be produced in real time; and that

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6 See Michael Bridge, Benjamin’s Sale of Goods (10th ed, Sweet and Maxwell 2017) 1-085 and the sources cited there.

7 These include the capacity in MW that the generator can be required to generate, the frequency ranges the electricity must comply with and the other required operating characteristics it must have.

8 Discussed below under “Capacity Charge”.

9 Very specific metering clauses usually apply, with meters being sealed, opportunities for joint inspections, testing and readings and processes for recalibration and, usually, corrective payments if inaccuracies are detected.

10 The wires from the generating set to the power station border are owned by the generator. The high and low voltage transmission and distribution networks through which the power is then transported are owned by transmission and distribution network operators which function as regulated monopolies. In some countries, these functions are combined in a single utility. The wires from the consumer’s connection point with the distribution network to the consumer’s appliances are owned by the consumer.

11 This will usually be a condition precedent to the sale. The generator will need to comply with standard connection requirements and meet the prescribed level of fees. If the power purchaser is the local utility it will often be liable if any failure by it to maintain the connection prevents delivery of power.

12 This is achieved by stating in the PPA that the point for delivery is at the connection between the generating station and the relevant transmission or distribution system.

13 This means the generator must undertake, in its connection agreement with the relevant transmission or distribution company, to comply with the operational and other requirements of the applicable Grid or Distribution Code.

14 Electrical energy can be converted into other forms of energy either by being used to pump water to higher altitude storage reservoirs and then used later to create hydro-electric power. Or it can be used to charge batteries
business and domestic demand for electricity varies enormously between different times of day, between working days and weekends, and between different seasons. This combination of factors means the market value of electricity fluctuates a great deal, within broad though relatively predictable parameters; and that satisfying demand requires a series of complex processes and time critical judgments, as illustrated below.

3. **The processes used to decide when a power station is to generate**

The challenge faced by system operators and suppliers is, therefore, to meet their customers’ fluctuating demand using the most economical combination of power stations that can be scheduled to run at the relevant time, bearing in mind the operational status of each power station and the technical flexibility it has to respond to changed instructions.\(^{15}\) This is a complex task, bearing in mind that the available portfolio of power stations will normally be quite varied. At one end of the spectrum, the portfolio will contain power stations that, while they were expensive to build, are considered cheap to run, but which may also be relatively expensive to shut down and start up. These are best suited to constant “baseload” running. At the other end of the spectrum there will be power stations that are more flexible and are therefore able to cope with short term operational changes as they service the peaks in customer demand.\(^{16}\) These are used for medium “mid merit” and “peak” consumption conditions. However, they can cost more to run, partly because of the cost of fuel and partly because they must in economic terms justify and recover their fixed costs over a smaller number of running hours. There are also many variations within this range and some generation types that must run\(^{17}\) or that will in practice run\(^{18}\) irrespective of these considerations.

The complexity of the system operator’s task is further increased by the need to fine tune the proposed running order. The system operator starts to schedule generating plant at the “day ahead” stage in anticipation of running to meet the next day’s predicted demand. It then refines the schedule to reflect changes in power station status and differences between the constantly updated predictions of likely demand and the actual amount of power taken by consumers in real time.

4. **The consequences of the scheduling and dispatch process for PPA design**

This very simplified description of the process that has to take place in order to schedule and dispatch generating plant to meet demand identifies a number of features that have a fundamental effect on PPA design, particularly in simpler markets where the role of independent power projects is only to sell to established supply companies or to a central national procurement entity.

The key factor is that a power station will not necessarily be called upon to generate at all times and the decision on whether to run it will not be made by the generator. This means

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\(^{15}\) The order in which power stations are called on to generate as a result of the system operator’s optimisation of these factors is known as the “merit order”.

\(^{16}\) Combined cycle gas turbine power stations are an example of more flexible plant. Hydro-electric and pumped storage plant are the most flexible form of generation as they can produce power almost immediately when the water is released to drive the turbines in the generation plant.

\(^{17}\) Nuclear power stations are a good example of power stations that must run for long periods due to the complexity, risks and costs of a shutdown.

\(^{18}\) Wind and solar power are examples of forms of generation that, while intermittent, will be produced at zero marginal cost when wind and light conditions permit unless positively disconnected.
the generator will not normally want to make the recovery of its fixed costs and profit margin dependent on unpredictable and potentially subjective decisions by the system operator about whether to run the power station. Generators therefore normally seek a fixed monthly “capacity” charge that covers these costs irrespective of actual use and a variable “energy” charge that is paid for each unit of electricity the power station is required to produce and that is designed to recover only the short run marginal costs caused by actually generating – in practice, mainly fuel.\

This structure also suits system operators and power purchasers very well. In helps keep costs down, because the overall price charged for electricity should in principle be lower under this structure because it removes risk for the generator and therefore the need for a risk premium that would otherwise be charged. In addition, a separate payment for capacity makes sense, as capacity has a very real economic and practical value in itself and also has regulatory importance for power systems and suppliers. This value arises because most national power systems aim to maintain a stated target margin of spare generating reserve that is expected to be available to generate if the power stations that are actually due to run are for any reason unable to do so or if unusual circumstances cause a larger than expected demand. This requirement can take the form of an explicit legislative obligation to supply that is placed on certain licensed suppliers, breach of which leads to legal sanctions; or it may be expressed as a requirement to own or contract for a stated volume of capacity; or it can be implicit in a duty to have measures in place that keep the “loss of load probability” below stated levels. Having legally binding contracts in place that require capacity to be available is one way of demonstrating compliance with explicit capacity reserve requirements. The fact that the power station can be called on to generate even at unexpected times provides comfort that the loss of load probability is low so that significant failure to supply is unlikely to occur.

A dual capacity and energy charge structure is also very compatible with way that power stations are scheduled and dispatched. As described above, to optimize the economics of meeting demand, the system operator needs to make judgements between the relative costs of running different power stations. This can best be done if the system operator knows the marginal cost of production of each power station at the relevant time. For power stations that the utility owns, this is an internally known fact. For power plants that a utility does not own, but that operate under contract with separate capacity and energy charges, the energy charge will normally represent the short run marginal costs of that power station. So, this pricing structure is operationally useful in many systems because it enables the system operator to make the necessary economically rational choices between these different power stations.

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This describes the normal choice for independent power generation project companies with a single power station and a long-term PPA. Larger generating companies with a portfolio of power stations are often prepared to sell power on a firm basis and manage the fluctuations in their various stations’ output across the portfolio and by spot market trading. Clearly that approach means incorporating a significantly different allocation of risks when designing the PPA.

As explained below, sometimes minimum purchase obligations in underlying fuel supply contracts – known as “minimum take” or, traditionally, “take or pay” clauses - have to be reflected in PPAs. This can mean that fuel is not always a cost that varies solely according to output levels.

These could include orders to comply with the obligation which if breached could lead to liability, financial penalties or adjustments to recoverable tariffs.

This is not applicable in some systems with formalised spot markets. There, separate obligations may exist under the applicable market rules that require generators to disclose actual availability and that remunerate production by reference to spot market prices, unless parties to the PPA have exempted the volumes they have traded with each other from settlement at the spot price.
The need to facilitate system operation also leads to PPAs specifying the other technical capabilities and operating constraints of a power station that may limit its ability to run when instructed\(^\text{23}\) or that may cause additional costs that the generator will seek to recover. For example, a PPA will normally specify the “start-up” time required for a generating set to begin producing electricity and the “ramp up rate” at which it can increase levels of generation in response to system operator instructions. The system operator has to take these and other contractually specified constraints\(^\text{24}\) into account when deciding what stations to schedule. If the system operator’s instructions to generate infringe these limitations, the generator will be protected against liability and reductions in capacity payments if it fails to generate.

Similarly, PPAs will often specify additional charges for responding to particular instructions. A start usually requires much more fuel and causes more wear and tear than a simple increase in the level of generation so there is often a specific charge for that.\(^\text{25}\) Operating at above maximum design capacity in emergency situations\(^\text{26}\) can entail disproportionate wear and tear and costs, so there can be an additional charge for that. Sometimes power stations are required to run in particular operating modes that help preserve the stability of the electricity transmission system,\(^\text{27}\) and receive a differently calculated charge that reflects the nature and costs of those modes of running. The rationale for these additional charges is to ensure that the choices made by the system operator do not impose disproportionate additional costs\(^\text{28}\) on the generator without appropriate compensation.

The above is a deliberately simplified summary of a very complex and interrelated set of economic realities and technical processes, but it helps to illustrate how the distinctive features of electricity as a product have generally led contracting parties to adopt this particular structure for PPAs.

Of course, there can be significant variations to this basic structure. For example, some thermal power is sold under PPAs that do not have a separate capacity and energy charge. Instead, these PPAs aim to recover fixed costs by having a higher charge per unit of electricity coupled with an obligation on the power purchaser to instruct the power station to run for a certain number of hours a year\(^\text{29}\). If the power purchaser breaches that obligation, it is obliged to pay the charge for the missing number of hours, less the cost of fuel not burnt.

Similarly, PPAs for wind, solar and hydro power generation projects do not have a dual capacity and energy charge structure as there is no separate fuel cost to charge for. They therefore either specify a capacity charge that entitles the purchaser to the full output of the

\(^{23}\) These are widely referred to as “dynamic parameters” or “dynamic characteristics”.

\(^{24}\) In systems where there is a mandatory spot market, the system operator may not be party to the PPA. These characteristics are therefore notified under applicable grid codes and spot market rules.

\(^{25}\) The charge, and indeed the time taken, will often vary according to whether it is a “cold start” when the power station has not been operating for a period so that it boilers have to be fired up or a “hot start”, when the power station is already partially prepared to start running.

\(^{26}\) This is often known as “max-gen” or maximum generation.

\(^{27}\) These include running in spinning reserve mode, ready to be synchronised with the grid and start generation at shorter notice; and providing what is known as “reactive power” by running in a manner not designed to optimise generation levels but that instead helps to maintain system stability.

\(^{28}\) In some cases, such as providing “reactive power” for system stability purposes, there can be a significant opportunity cost if the power station would otherwise have been selected to generate in the normal way.

\(^{29}\) Clearly this structure can be risky for the generator as, if the generating plant unavailable at the required time, it can risk losing a substantial part of the fixed costs it aims to recover. For this reason, the best approach is to structure the mandatory dispatch obligation in a way that allows both parties sufficient flexibility to use the capacity when it is both available and needed.
plant but the charge is adjusted to reflect any shortfall in availability below targeted levels; or else they give no firm commitment on output but charge a price per unit generated and contain an obligation on the power purchaser to purchase all actual output. The generators rely on this, and on the fact that seasonal wind and sunshine patterns can broadly be predicted from past records, as their assurance that they should over time recover their fixed costs and make a profit.

The above description focusses, for simplicity, on systems where power is sold by independent power projects to a single state-owned utility that combines the functions of system operator and monopoly supplier to customers. Other more complex market structures exist, particularly in developed jurisdictions that have liberalized their markets for competition policy reasons and have therefore introduced a mandatory spot market for all sales of power by generators. Long term PPAs can also be implemented in those market structures, in several different ways explained below.

This can be done simply by arranging the generator sell power under a slightly modified form of a classic PPA and leaving it for the power purchaser to take responsibility for putting the power into the spot market as seller and for taking it out as buyer. Alternatively, many market structures make it possible for sellers and buyers to make notifications to the market operator that match their respective inputs and outputs. This allows a seller and a power purchaser to exempt matching or jointly notified trades under a PPA from the obligation under the market rules to pay and receive the spot price. Another possibility is for the generator to sell the relevant output into the spot market which entitles it to receive the spot price and enter into a swap or difference contract with a power purchaser. The power purchaser then buys the same quantity of power out of the spot market, but the payments under the swap contract leave them each in the same net position as if the power had been sold directly at the agreed long term contractual strike price.

These arrangements tend to depart more from the classic PPA model and may entail a higher risk profile and greater market price exposure for the generator. This is because the parties usually expect these contracts to make far fewer references to the physical characteristics of the underlying power station, so that they are more compatible with the other commodity derivatives that are traded in the market. These forms of PPA are mentioned because they show that the PPA model can be adapted to suit very different market structures and risk profiles. More detailed review of the terms of these variants is however outside the scope of this analysis.

5. **Key characteristics of long term PPAs that are not electricity specific**

PPAs are also shaped by many other important characteristics that are not unique to the electricity industry, but which are also found in other long-term offtake feedstock and service contracts, particularly in the energy, natural resource and infrastructure sectors and in public private partnership contracts. These features arise wherever a long-term contract requires the use of capital intensive assets with high up-front construction costs or upstream development costs that need to be recovered over the expected useful life of the asset, as the asset performs the expected services. The result is an economic imbalance at different points in the contract life between costs incurred and revenues received, which creates

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30 A recent market trend in some wind PPAs is to offer a firm commitment at levels well below expected output of the wind farm and sell the extra generation it produces into the spot market; and, if required, to have back up supply or hedging arrangements in place in case of greater than expected shortfalls in generation by the wind farm.

31 A key risk for large wind farms is that other wind farms may in future be built in the vicinity that detract from the wind that reaches them.

32 Sometimes the contract for differences may be with a power trader rather than a generator or supplier.
particular vulnerability for the producer. This vulnerability is often enhanced because the assets, by their nature, risk in practice being dependent on a single purchaser, which is often state owned or has a legal or practical monopoly or other market power over the ultimate end-use market.

There are many reasons why purchasers might choose to make different purchasing choices in future if free to do so, as illustrated below. So, if the risk of that happening is not priced into the project at the outset, it is necessary to exclude the possibility by creating a legally enforceable purchasing obligation in the long term PPA or other agreement, rather than relying on purchasers choosing to continue buying the product or service the asset provides.

For example, technological change and shifts in government and regulatory policy are key risks in the power sector. If, after a power station has been built, a new and more efficient form of power generation technology is developed and the electricity supply company is entitled to start buying its power elsewhere, the original power station will have to lower prices, thereby undermining cost recovery and investment return, lowering the overall value of the project company, and risking insolvency. The same can at times happen even if the preferred form of power generation may at least initially be more expensive - for example, if environmental policy drives a move away from existing technology, such as coal-fired generation, or towards new technology, such as renewable generation. A secure long-term PPA is therefore necessary if the intention is to protect the generator against these risks.

The need for this protection is increased in the case of major infrastructure projects by the frequent lack of real competition between potential buyers, particularly in non-liberalized markets, and by the vulnerability caused by the physically embedded nature of the asset. If lack of competition means there is only one potential purchaser for the output of a power station, the developers need to put a long-term contract in place with the utility before they are committed to construct it. Until construction starts, the developers have a relatively equal bargaining position with the power purchaser as they can always refuse to incur the expenditure; but the developers' bargaining position becomes much weaker once construction starts, because the costs are sunk, and normally it is not physically or economically practical to take the assets back during or after construction and earn revenue elsewhere.

Like other long-term infrastructure contracts, PPAs also have to address the events that can take place during their lifetime, which destabilize the economic and other assumptions that underpinned the original pricing and performance terms. For example, changes in environmental and other laws, and changes in the price and availability of fuel lead to cost changes. The generator can only be sure of passing these on if it has a long term PPA that entitles it to do so. Force majeure events disrupt performance and reduce the generator’s earnings. A PPA will not normally cover these revenue losses, but it will prevent the power purchaser from terminating the whole PPA unless prolonged. PPAs also have to cater for potential credit risk from the offtaker and for the risk of political force majeure.

33 This is what happened to much conventional thermal generating capacity when combined cycle gas turbine technology was introduced and enabled to capture market share in newly liberalised electricity markets such as the UK.

34 There are important exceptions, such as barge-mounted and ship-mounted power stations that are available at short notice and can be withdrawn just as quickly; and power stations composed of groups of small modular diesel fuelled generators, which can be assembled at and land sites and removed when no longer needed (assuming the government allows this). The British power developer Aggreko specialises in these. They are often used in emerging markets and are particularly useful for meeting immediate needs for new generating capacity. However, cost and scale mean that they are not generally seen as attractive long-term solutions.
nationalisation, or the break-up of the utility power purchaser or state-owned fuel supplier as part of a market liberalisation process whose possible form is as yet unknown.

Paradoxically, these risks often present themselves in the most acute form in the very countries where the need for major infrastructure projects is the greatest, namely, in developing countries where infrastructure sector has not been liberalized so that there is only one practical customer, and where foreign equity and debt capital may perceive particularly high risk. This happens because, in practice, the first privately financed international investments in developing countries are often made in the energy and natural resources sectors. While oil gas and mining projects are developed with a view to generating substantial proportions of their revenue from export sales, the distinctive characteristic of independent power projects is that they are often the first international energy sector investments that have an exclusively domestic customer base. This means that in many emerging market jurisdictions, these issues are addressed for the first time when the country begins to seek investment in new independent power projects. The rest of this chapter will therefore focus on a typical emerging market long term PPA to see how the product and market characteristics described above are reflected in the practical detail of risk allocation and contract design.

6. Making the Capacity Charge work

We have seen the rationale for having separate capacity and energy charges. However, the capacity charge raises several issues that require careful treatment when designing PPAs to make sure the power purchaser gets what it pays for. One such issue is availability. Power stations are often not available at their full design (or “nameplate”) capacity. The exact level of availability that a generator achieves depends on prevailing conditions that are beyond its control and on a series of maintenance and operational decisions that are within its control. To incentivize maximum availability, many PPAs therefore establish a target percentage availability and apply a regime of bonuses and rebates to the capacity charge, depending on whether the power station achieves that target availability in the relevant measurement period. In some cases, the generator would be credited with availability when the PPA states that the risks that prevented it from being available are not its responsibility: for example, in case of political force majeure. Ordinary force majeure would normally not be excused — so the capacity payments would be reduced for resultant unavailability. These incentives are seen as the main assurance that the power purchaser will get the availability it has contracted for.

The problem is that this system relies on the generator declaring its availability accurately and honestly. The accuracy of the declaration will clearly be tested if the power station is called on to run. However, if the power plant is not fully available but the generator thinks the power station is unlikely to be needed, the generator may be tempted to make an incorrect declaration in the hope of avoiding a rebate for poor availability. To counteract this, the system operator/power purchaser will often test a plant that has declared itself fully available even if it would not otherwise be scheduled.

Either way, if the power station fails to operate as instructed, sanctions will apply under the PPA. Clearly, for the period in question, the capacity charge is not paid for the actual volume of lost output. Usually, there is an additional deduction of several times that amount from

35 This is discussed below in section 13.

36 Care has traditionally been taken to define these amounts as rebates not as damages and not to refer to them in the contract as “penalties” due to concerns about potential unenforceability. Recent English caselaw indicates more likely acceptance that provisions of this kind in a negotiated contract would serve a separate legitimate commercial purpose and therefore be valid. Cavendish Square Holding BV v Talal El Makdessi; and ParkingEye Ltd v Beavis [2015] UKSC 67.
the overall monthly capacity charge, to act as a deterrent to mis-declarations. Often, these additional sanctions will include disregarding future declarations of availability for a stated period unless the power plant is called on to run. Sometimes, declarations are also disregarded retrospectively for a similar period except to the extent that the power station actually ran. Some PPAs will not apply a penalty if failure to operate was due unforeseeable events of force majeure as this was unanticipated and does not indicate intentional misdeclaration37.

The levels of bonuses and rebates vary. Bonuses are normally capped at nameplate capacity. Often the amount paid per MWh as a bonus for exceeding target availability is lower than the amount per MWh rebated for falling short of target availability. This is because the purpose of the regime is to incentivize the delivery of the expected capacity. Higher than target availability may well not be needed, and therefore has a lower value to the power purchaser. Lower than expected availability is a problem, so greater rebates may be appropriate. For this reason, PPAs will at least make a pro rata reduction in capacity charge for shortfalls in average availability compared with target availability: for the first tranche of any shortfall the rebate is likely to be more than pro-rata, to create an economic incentive to eliminate avoidable losses.

Declared availability can also be disallowed for other reasons: for example, if an inspection visit, a formal test result or other objective evidence demonstrates that the plant was not capable of generating at a time when it was declared available, PPAs generally also contain a right to conduct a certain number of capacity tests each year to verify that the maximum declared net capacity or nameplate capacity can actually be achieved. If not, then the PPA normally provides that the power station is de-rated, which means the maximum capacity is reduced proportionately, and the monthly capacity charges are calculated from this reduced base amount.

PPAs also supplement these economic incentives to deliver the promised capacity by including some basic legal assurances. One frequently seen clause is a contractual undertaking that the generator will seek38 to maximize availability or at least to achieve target availability. This is often heavily debated as generators may want only the financial incentives to apply, as the incremental costs required to improve availability to these levels may in some cases exceed the likely extra resultant revenue. Generators can also be concerned that allegations of breach may be used as a basis for terminating the contract if its pricing becomes unattractive to the power purchaser.

Another legal source of comfort is a commitment that the generator will not sell electricity from the power station to anyone else. This is often heavily debated but, if secured, obviously ensures that the generator does not make a windfall profit when the main purchaser has borne all the fixed costs39. The generator may however try to negotiate consent to sales to third parties no doubt in exchange for a share of the additional revenue.

37 This approach is an exception from the normal position that force majeure leads to a pro-rata reduction in capacity payments. The combined effect of the customary provisions is that the generator would lose the usual level of capacity payment but would not suffer an additional disproportionate loss of revenue by way of sanction for intentional misdeclaration (assuming the force majeure event was notified as soon as it was known).

38 The strength of this obligation is also often debated – with suggestions from reasonable to all reasonable or best endeavours. Care is needed in jurisdictions where all reasonable or best endeavours may be interpreted as requiring disproportionate efforts or cost (or where the legal position is unclear as in many common law jurisdictions).

39 This is particularly sensitive where the third-party purchaser is able to buy incremental output at below the average price and is then able to use that electricity to undercut sales to consumers by the main power purchaser.
Finally. It should be noted that while periodic capacity charges are often misleadingly described as “fixed charges” or “base charges”, they are normally drafted in a way that provides for predetermined variations over the duration of the contract to reflect the underlying commercial terms that have been agreed. As seen above, they may be adjusted to reflect the amount of capacity made available. Elements of the charge may also be subject to indexation, at least in relation to the portion of the underlying costs that are not just historic. If debt service costs are not already hedged, exchange rate fluctuations may lead to an adjustment of part of the capacity charge as well. Similarly, elements of the charge that reflect historic or current costs that are incurred in foreign currency may also be adjusted to reflect exchange rate fluctuations.

7. **Energy charges and fuel risks**

   The energy charge, as discussed above, is supposed to represent the short run marginal costs of generating so it is really intended to reflect the cost of fuel used. Because the cost of fuel over the lifetime of a long term PPA for thermal power will normally be very large, the energy charge needs to be very carefully designed to ensure the correct allocation of risks between the parties.

   In principle, the power project company will not want to take risk on the cost of fuel, because it cannot rely on making any profit to by doing so. However, the power purchaser’s willingness to take the risk on fuel costs is based on an assumption that the power station operates with the promised level of efficiency in turning fuel into electricity. Ensuring this happens is the generator’s responsibility and risk. If the power station operates inefficiently, the power purchaser will not want to incur the resultant extra charges. The amount of the energy charge that is due is therefore computed on the assumption that the plant maintains the contracted thermal efficiency or “heat rate” and the generator normally bears the risk of having to pay for any excess fuel required. Often, the heat rate a power station can achieve is only clear at completion of construction and may well differ from the level specified at the design stage. This means that the heat rate is usually tested during commissioning tests when construction is completed, and a heat rate is established then. The energy charge under the PPA is then computed on the basis of the lower actual level of thermal efficiency achieved during the commissioning tests. Some PPAs will also provide for capped liquidated damages to the power purchaser if the heat rate is less efficient than the contractual specification. These will reflect whatever liquidated damages the generator can recover under the construction contract for the power station.

   Fuel prices can be very volatile, and the risk of significant fuel price movements is not normally factored into the economics of the project company. Thus, when the price of fuel moves, the energy charge in the PPA is also adjusted accordingly. Where a specific fuel source is used under a long-term fuel contract, any changes in the price under that contract are normally passed straight through to the purchaser by way of an adjustment to the energy charge. Where the fuel is bought on liquid world markets, two approaches are possible. Under one approach, the initially agreed price simply adjusts by reference to movements in agreed fuel market price indices. The other approach is to make the project the fuel procurement manager and to pass through the actual fuel prices achieved, perhaps with the generator retaining a limited incentive payment if the results of its fuel procurement process exceed specified targets.

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40 This is obviously not the case for solar wind and hydro power.

41 Sometimes power project developers are thought to specify unambitious heat rates with a view to making profit on subsequent energy charges: careful checking of specification and the testing process just described also help protect against this.
8. **Take or Pay clauses in fuel contracts**

Often gas or coal-fired power stations are fuelled under a long-term fuel supply contract that contains a “take or pay” clause. If so, this will normally be reflected in the PPA and the power purchaser will be contractually obliged to run the power station often enough to enable the power station to consume the minimum volume of gas which it has committed to purchase under the gas supply contract. If the power station is not instructed to run at these levels, the net additional costs incurred by the generator under the fuel contract are passed on to the power purchaser, after taking account of any other associated benefits under the gas contract take or pay clause, such as rights to free “make up” gas in future within certain time limits. The take or pay obligation in the PPA may however be reduced if the power station’s availability is below target, if that prevents the power purchaser from achieving the minimum dispatch required, unless the shortfall in power station availability is due to power purchaser breach or certain types of force majeure.  

9. **Fuel supply risk**

The most difficult issues arise if the fuel does not arrive as and when specified under the fuel supply agreement. The key question, if replacement fuel can be found, is who should bear any additional fuel cost. If replacement fuel is not found, the question that arises is whether the power station will be treated as unavailable in this situation. If so, it will lose capacity charge income, which is a major issue for it.

The way the PPA allocates these costs and liabilities generally depends on the reasons for the non-delivery. If it is due to fuel supplier default, some liquidated damages may be available under the fuel supply agreement. However, they may well be insufficient to cover the potential loss of capacity charge under the PPA if the power plant is deemed unavailable. Sometimes liquidated damages can be specifically negotiated with the power project in mind, as can happen for example with a gas supply contract from a specific dedicated gas field. If so, the liquidated damages may cover the capacity charges that the power project loses under the PPA, or the PPA may state that the generator passes the liquidated damages on to the power purchaser but is deemed to have been available so that the capacity charge remains payable. However, if the interruption is due to force majeure affecting the fuel supplier, there will not be any compensation due under the fuel supply contract and there will be a correspondingly stronger case for the power station to be treated as available for capacity charge purposes, as long as efforts have been made to source alternative fuel.

One of the best approaches for a generator to take at the outset of negotiations is to characterize the contract not as an agreement for the sale of power, but as a contract for the service of turning the customer’s fuel into electricity – known as an “energy conversion agreement” or a “toll processing agreement”. This simple change in terminology can often achieve a major change in contractual risk allocation, because if it is adopted, the natural consequence is that all fuel supply risks automatically lie with the offtaker; whereas if the

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42 This approach would generally apply to political force majeure in an emerging market PPA with a state-owned power purchaser. The position on whether ordinary force majeure affecting the power station would diminish the power purchaser’s minimum dispatch obligations would depend on the outcome of negotiations and in particular on whether the price of the fuel, which benefits the power purchaser, was lower because of the minimum take obligation.

43 The overall effect of the two approaches would normally be the same but different practical results may follow from the approaches if the fuel supplier, the generating company or indeed the power purchaser fail to meet their payment obligations. The generating company will normally prefer to be deemed available and to pass on whatever liquidated damages it actually receives from the fuel supplier. This approach suits the generator better as it maintains its normal revenue flow and the benefit of any government guarantee of power purchaser payment obligations, which would not normally apply to fuel supplier obligations.
agreement remains described as a sale and purchase, the natural assumption is that the
generator organizes fuel supply and takes the resultant risks. Then the generator has to
negotiate hard to transfer these to the power purchaser utility, even though the utility is
arguably better placed to spread these risks across its customer base.

10. **Credit risk**

The risk that the power purchaser may not pay is a major danger for the generator under a
long term PPA. Even in markets where alternative buyers exist, termination for non-payment
can result in losses to the power generator if the capacity or power is re-sold at a lower
price. The risks are however particularly acute in jurisdictions where there is only one
realistic buyer, for example where the power utility is a monopoly which is often also state-
owned. This is normally the case in developing countries, where other economic and political
factors can exacerbate the problem. State controlled utilities can present a high credit risk if
there is no stable regulatory formula that allows tariffs to keep pace with costs, if there is a
history of poor collections from consumers or if there is a track record or perceived risk of
interference with power prices for short-term political reasons. Similarly, there can be a
perceived risk that a change of regime or of government policy may reduce political support
for foreign owned or financed independent power projects and therefore increase the
chances that the state will not take steps to make sure the utility is able to make payments to
them.

The problems are enhanced where governments use the state-owned utility as a vehicle for
implementing economic and social policy by keeping tariffs at uneconomically low rates or
implementing cross subsidies to domestic or agricultural sectors. Whatever the merits of
these policies may be, they can tend to undermine the financial strength of the utility. This
also makes the cost of electricity from new power stations (which is normally already higher
than the average cost of power from existing power plants that were paid for long ago) seem
particularly expensive compared with the average tariffs charged by the utility. This makes
these PPAs vulnerable to attempts to terminate or destabilize them at times of political or
financial crisis.

For all these reasons, independent power projects and their financiers usually seek short
term credit support backed up by long-term guarantees from the state, through its finance
ministry, of the power purchaser’s payment obligations under the PPA, if the state owns
the power purchaser. The willingness of a state to give such guarantees is often in effect a
pre-condition to attracting developer interest, unless the state and utility are particularly
strong. Sometimes states try to put a time limit on the guarantee or else limit it to energy
charges and a portion of the capacity charges so as only to cover debt service repayments,
though this is typically resisted. The medium-term target for states in emerging markets is to
grow the financial strength and stability of their utilities to the stage where the need for these
guarantees can be limited or eventually eliminated, without thereby jeopardising the states’
ability, in the meantime, to attract the investment necessary to develop the electricity
generating capacity they need to underpin economic growth.

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44 Note that a guarantee from the state to the project company that the power purchaser will meet its payment
obligations under the PPA is very different from a guarantee by the state to the project company’s lenders that the
project company will repay its loans. The difference is that the obligation to make payments under the PPA only
arises if the power project has fulfilled its obligations to generate power. A direct state guarantee to lenders would
mean the state assuming project risk instead of the lenders doing so. Occasionally the distinction is lost in
discussions about a state guarantee, but a direct state guarantee to lenders would now be extremely unusual.
11. Liability for a failure to deliver power: exclusion of consequential loss liability

As shown above, long term PPAs of the kind used by independent power projects are non-firm rather than firm, which means that the generator does not absolutely promise that power will be available at all times. That said, the generator does receive a fixed monthly capacity charge and is therefore expected to maximize availability. As explained above P45 PPAs therefore include financial bonuses and rebates that incentivize generator to the achieve the target availability and financial sanctions for false declarations of availability. These create confidence that the generating capacity being paid for is actually available for use, if required. They also create a strong financial sanction for a failure to deliver power in the form of a loss of revenue to the generator. This reduction in revenue due to rebates is formulated as an adjustment to the price payable, which is, different, conceptually and legally, from the contractual liability that a generator could have for breaching its obligation to deliver power.46

The analysis in the following paragraphs will show how the legal complexities of calculating actual recoverable loss and the potential magnitude of the economic losses caused by failure to supply have led to a market practice of limiting or excluding liability for damages for breach of contractual obligations to generate electricity and relying instead on the incentive mechanisms described above. This is best illustrated by analysing two important categories of damages liability, each of which could be very costly, and is driven by different factors.

One category of liability that is often excluded is the potential liability of a generator to a power supplier to compensate the power supplier for the additional cost of purchasing alternative power to replace the missing output. In a country where there is a liquid spot market for power and alternative generation is available, the cost would usually be the amount by which the spot market price at the time of the shortfall exceeds the price in the PPA. However, in a country where there is a single integrated supply utility which has a portfolio of owned generating plant and PPAs, the position is more complex. The utility’s loss would only be the additional costs of obtaining the power from one of these existing sources. In many cases this would just be the extra fuel cost of generating at a higher level from a power station that the utility already owns. Because the utility would not have to pay itself for the use of capacity it already owns, this additional cost would often be lower than the cost of buying power in a spot market where the implicit capacity value in the spot price is high at times of peak power demand. Alternatively, the utility’s other PPAs may entitle it to additional power at the applicable energy charge, without any obligation to pay any additional capacity charge. Either way, this additional fuel cost is in practice likely to be less than the savings the power purchaser realizes due to the reduction in capacity charge under the PPA with the defaulting generator. Consequently, classic calculations of damages might well not result in any payments at all, even if contractual liability were not excluded.

The computation of the power purchaser’s losses would however be different if the failure to generate occurs at times of peak demand when there is no additional capacity on the system to create replacement power, even using the margin of reserve capacity that is usually held in readiness. Paradoxically, the actual financial loss to the power purchaser may be even less in this situation. This is because suppliers traditionally exclude or cap their

45 See section 6 “Making the Capacity Charge work”, above.
46 Note that in the typical non-firm PPA this obligation could only arise after the power station had actually been instructed to produce power after declaring itself available to generate. In a firm PPA, the contractual liability would arise irrespective of the operational condition of the power station.
47 For the discussion of the assessment of damages under English law in this volume, see A Tettenborn, ‘Abstract Damages in International Sale Contracts – When should They be Available?’
liabilities to customer, with the result that disconnecting customers usually does not result in major short-term liabilities for the power supply company. While there may be specific regulatory penalties in place for disconnections, these are not universal and may in cases be less than the actual costs saved. This again means that the characteristics of the electricity market structure make classic damages computations difficult to apply and mean that damages for breach of contract are a relatively impractical form of sanction for failure to generate power. His practice of generators limiting liability to power purchasers who in turn limit their liability to ultimate consumers is very widespread within the industry. It has arisen because of the potential for very high levels of economic and consequential loss. It is easy to see how these losses could arise. Electricity is a key precondition for almost all forms of economic activity and an interruption in power supplies can suspend production and result in huge losses of revenue by consumers. The view that seems to be taken when deciding to limit contractual liability for this is that, if a power supply company were liable for the true economic cost of these suspensions, its financial stability would be jeopardized. The utility would have to charge a very high premium to cover the risk, which would make power more expensive than consumers would want or, in some cases, could afford. It is therefore considered better to have a market and regulatory structure that requires suppliers to take reasonable steps to provide for adequate capacity for the system as a whole, but to leave users to make individual arrangements to counteract the risk of shortfalls if it is worthwhile for them to do so (for example, by installing a back-up generator if the need justifies the costs). In other words, the limit on liability is based on an assumption that consumers are better able to bear or manage this residual risk at reasonable cost than power suppliers are. It is easy to see why, against this background, power purchasers have looked for price adjustment clauses to deal with poor availability and non-delivery of power, rather than rely solely on liability for normal contractual damages to protect them. For the same reasons, generators and suppliers routinely exclude contractual liability for consequential and economic losses and loss of revenue.

12. **Change in law**

The price formula contained in a long term PPA is defined at the outset and lasts for the duration of the agreement. The price will be based on the generator’s understanding of the costs that are imposed on it by national legislation at that time and, sometimes, any known impending changes. If a change in legislation causes those costs to increase, the generating company will not be able to recover them from its purchaser unless the PPA expressly allows it to do so. If the generator were uncontracted and operating in a fully competitive market structure it would, like any other business, at least seek to pass these costs on to consumers through higher prices. This is why change in law clauses appear in long-term PPAs and in PPAs where there is not a reliable competitive market for the re-sale of the capacity. In short-term PPAs in liquid markets, however, change in law clauses are not normally used, because the risk is considered manageable for a short period and generators are expected to try and recover the increased costs when they recontract.

For this reason, long-term PPAs will normally contain a clause that entitles them to pass on increases in costs caused by changes in law. The PPA normally obliges the generator to seek to minimize the costs. The change is normally passed on by means of an increase in

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48 This passage describes the thinking behind the decision taken to exclude liability for consequential and economic loss during the establishment of the UK electricity market structure at privatisation, when the author was directly involved.

49 It is difficult to say whether this assumption is formally tested when these decisions are taken, but the same choice seems to be made in most situations.
tariff. The clause often contains a mechanism for agreeing the scope of any major capital works that are required by the change so that the generator is not at risk of carrying out the work and subsequently risking a determination that there was a more cost-effective way to comply with the change. The PPA may expressly state that equity investment needed to fund capital expenditure will earn a rate of return and that the cost of debt finance will also be factored into the change in the PPA tariff; and it may provide the alternative of the utility or state funding the capital expenditure up front so as to avoid these elements of cost. There may be an agreed annual threshold below which no change is made. The clause will usually be reciprocal in the sense that in the unlikely event that a change in law reduces costs, the price under the PPA will be reduced. Changes in tax are also usually included as triggering price adjustment, though generally applicable changes in direct tax on profits or turnover are often excluded on the basis that all businesses in the country have to bear these. A clause would normally be written so as expressly to capture reductions in net revenue as well as increases in costs, in part so as to ensure that changes in tax are covered that are not necessarily within the strict definition of costs.

There are many ways of drafting the change in law clause. One very good way to capture the nature of the required adjustment is to provide that the contract is adjusted so that the generator is no better and no worse off as a result of the change and then to add further detail on the issues mentioned in the previous paragraph if negotiations permit this.

In principle, there can be overlap between change in law clauses and indexation clauses, as some general changes in law that affect businesses costs will feed through into general inflation; thus, if part of the PPA tariff is indexed (for example, labour costs), some of the impact may already be catered for. The drafting of change in law clauses does not usually address this explicitly, but the point could be raised in the process of quantifying and determining an actual claim.

13. **Political force majeure**

Generators usually insist on clauses protecting them against the impact of political force majeure, in countries where they see a risk of potential direct government interference (including expropriation, or direct governmental intervention) or where they see a risk of broader civil disturbance or other country risks adversely affecting the project. These clauses are not normally included in stable developed jurisdictions. At times, power purchasers try to restrict the clause to direct government action rather than third party action, on the basis that general instability is often part of overall country risk that should be reflected in the profit margin and rate of return that underlie the PPA.

The protection the clauses give is usually twofold. First, they provide that if political force majeure prevents the generator from complying with its obligations, the generator is deemed not to be in breach of the PPA and any necessary time periods for compliance are extended accordingly. This is the same as what happens under an ordinary force majeure clause. It

50 Sometimes, the PPA just gives a right to terminate the contract and claim a termination payment instead. This in principle prevents the generator from being locked into an uneconomic pricing formula. However, this is usually rejected as the size of the termination payment makes recovery much more problematic.

51 Occasionally power purchasers run the argument that change in law costs should be shared or even that reciprocity means they should pass on increases in their costs to generators. In a long-term contract this is a trap for the unwary as the logic is that costs ultimately need to be borne by those who use the services concerned, and this clause is simply about dealing with changes in the levels of costs originally reflected in the price.

52 As taxation is imposed by law, changes in tax are in practice normally covered anyway, even if not expressly mentioned.

53 Some developing countries give specific exemptions from taxes to new projects for a stated number of years. Where these cover profit tax, the state or power purchaser would be expected to pay compensation for any change.
simply ensures that the generator is not subject to liability for breach of contract or potential termination of the PPA.

The second area of protection concerns payments. The political force majeure clause will normally include language that makes sure that the generator is paid as if it had actually generated power at the required level. This additional statement is usually necessary because the PPA capacity charge and availability adjustments would otherwise reduce the fixed monthly capacity repayments to reflect the actual levels of generation achieved; they need to be corrected accordingly.

To prevent over-compensation, some clauses say that if the generator had been under-performing before the political force majeure event started, it will be paid at the level of performance previously being achieved, plus any improvement that was reasonably to be expected.

Political force majeure events may not just cause loss of revenue but can at times involve additional costs if for example there has been physical damage to the power station. Some PPAs cover these costs explicitly by an indemnity to the generating company from the power purchaser if it is state owned. Others leave compensation to other methods: direct government undertakings, insurance if available, or potentially investment treaty claims in case of expropriation.

Finally, PPAs also typically protect the generator against political force majeure by entitling the generator to terminate the PPA with compensation, if the force majeure is not remedied after a prolonged period – commonly 12 to 18 months.

14. **Ordinary force majeure**

A long term PPA would also normally contain a clause protecting the generator against ordinary force majeure, as distinct from political force majeure. Ordinary force majeure is usually defined as covering circumstances beyond the reasonable control of the generator such as storm, lightning, tsunami, extreme weather, “act of god”, explosion and fire not caused by an operational defect. Sometimes it includes industrial unrest, usually excluding the generator’s and its contractors’ workforces. There can be debate about whether the definition should be open ended or limited to stated categories of event. The most sensitive areas are faults, breakdown and the like, where the power purchaser is likely to consider it the generator’s responsibility to ensure a reliable power station. In some civil law jurisdictions, care must be taken if relying on ordinary contract law definitions of force majeure which may have a requirement that the event should be unforeseeable. This requirement would often not quite be met on power project interruptions, as the event may be predictable, but it may just be uneconomic or impractical to guard against the event. So, an express contractual formulation is usually deployed which avoids reference to the event not being foreseeable.

The PPA obliges the generator to take reasonable efforts to remedy the force majeure and resume performance and to inform the power purchaser promptly of the problem and about the efforts being made to remedy it and the progress being made. The obligation to try to remedy the force majeure may be qualified so that expenditure does not have to be incurred, if it is unlikely to yield additional net revenue, so that restoration is uneconomic, though that is arguably implicit in the requirement of reasonableness anyway. There may also be an exception from the obligation to try and remedy force majeure, if lenders to the generating project company exercise any rights they may have under finance documents to insist on insurance proceeds being applied to repay debt rather than rebuild the power station.
The protection given by the clause is to state that if ordinary force majeure prevents the generator from complying with its obligations the generator is deemed not to be in breach of the PPA and any necessary time periods are extended accordingly. The rationale is that, while the generator cannot expect to be paid for producing electricity when affected by force majeure, it should not have liability for breach of contract or liquidated damages. Often, the duration of the PPA may be extended by the period of extension for ordinary force majeure,\textsuperscript{54} to give the generator the opportunity to make up the shortfall in revenue, albeit much later.

The structure of the two-part capacity charge means care is needed in defining and implementing the principle that the generator should not receive the capacity charge when force majeure prevents it from generating electricity. If the capacity charge is defined by reference to actual availability achieved, the reduction follows automatically from the impact of the force majeure, in which case no express wording is needed. Express provision may have to be made in exceptional cases if the capacity charge is defined as a fixed amount and availability related reductions are described as liquidated damages for poor availability. Otherwise, the language stating that the generator is not in breach of contract when affected by force majeure may unintentionally remove the proportionate reduction in fixed payments.

The effect of force majeure on the generator is still very serious as the generator will not receive any revenue when it is not generating and there may be a need for expenditure in order to resume normal performance. Typically, the project company’s lenders will require the generator to take out business interruption insurance to cover it against loss of revenue for a period.

If the ordinary force majeure continues for a prolonged period without being remedied – usually about 9 months - and affects substantially all the output, the power purchaser would normally have a right to terminate the PPA. There may be extensions of this period where a programme of remedial works has been started and is being diligently pursued. In some cases, the power purchaser also has the right to terminate the PPA, after a longer period of trying to rectify the problem, so that the obligation to keep trying is not indefinite.

On termination, there may be a provision for sale of the power station at market value taking account of its condition.\textsuperscript{55}

15. \textbf{Expiry of the PPA}

The regimes for expiry and early termination of the PPA are often the most complex area in the PPA and one which is not necessarily thought through before the lawyers become involved.\textsuperscript{56} The regime that applies on expiry is heavily influenced by the fact that, typically, the contract length and payments specified in the PPA have been designed to recover the costs of building and operating the power station and to earn the expected profit for investors. In markets where a liquid market for selling power is expected to exist at the end of the life of the PPA, the parties may just decide to wait and see whether the power station has any useful life in it after the PPA expires. If the power station still works, the generator can sell the output for whatever it can get. If refurbishment is required, it can assess whether

\textsuperscript{54} Extension is not necessary in political force majeure as capacity payments should continue in full throughout.

\textsuperscript{55} See the discussion of termination payments in the following sections.

\textsuperscript{56} Often the importance of the residual value of the power station on PPA expiry is underestimated by developers because its net present value is low; and host governments often assume that they will for policy reasons want the power station to continue under private ownership so as to foster a competitive generation market, before fully taking on board that the state owned utility will already have paid for all the costs of developing the power station.
the likely additional revenue justifies the costs and risks involved. A PPA that takes this approach means the project is described as a “build – own – operate” or “BOO” project.

However, there is usually substantial uncertainty about whether there will be a competitive market for further capacity at the end of the expected PPA term. Also, respective self-interest tends to lead the parties to a solution where they seek contractual entitlements to require, at the expiry of the PPA, a transfer of ownership of the power station from the generator to the power purchaser. These would take the form of a “call option”, where the power purchaser could require the generator to sell the power station, or a “put option” where the generator could require the power purchaser to buy the power station. The transfers would be made at prices determined by reference to price formulae set out in the original PPA.

From the generator’s perspective, a put option prevents potential loss of whatever residual value the station or site may then have. Even if the net present value of the residual value is uncertain and is therefore not a central part of the financial case for building the power station, the power station is still an asset that should be able to earn revenue and the value, in accounting terms, of that potential additional revenue will be significantly greater towards the end of the PPA.

The power purchaser is likely to have a very different perspective. It will suspect that the generator is not factoring residual value into the key project economics and may well take the view that, as power purchaser it will have paid enough over the lifetime of the power station to cover all the associated costs and returns of building the station; so it might as well end up owning the power station, arguably at no cost. An approach involving automatic transfer would result in the project being characterized as a “build, own, operate and transfer” or “BOOT” project.

A structure that involves transfer at the end of the PPA will, however, inevitably raise additional issues and leads to difficult negotiations on price. The generator will seek a transfer at market value. The market price would be as agreed or, failing agreement, would be determined by an independent expert on the basis of an arm’s length sale by a willing buyer and seller. An express valuation assumption would disregard the fact that the buyer’s potential market power as the only realistic purchaser might otherwise enable it to insist on a low price. The power purchaser is likely to press for a right to receive a transfer of the power station at no cost, for the reasons stated above. If that is agreed, the generator may still seek agreement that some payment will be made if it has carried out refurbishment works that are likely to result in improved performance after the scheduled expiry date of the PPA.

Where the PPA does not provide for a costless transfer, the power purchaser is likely to argue that a market value transfer would only be appropriate under a call option, where it can choose whether to buy the power station. The rationale would be that, when the time comes, it may not need the capacity or want to source it from a power station with those characteristics. These considerations often lead to a structure where if the generator has a put option it is only at a lower valuation and where, if the power purchaser has a call option, the price is based on market value. Many other solutions are however possible, drawing on elements of each approach.\textsuperscript{57}

\textsuperscript{57}For example, a transfer at a discount to market price, to reflect the contribution made by the power purchaser to paying the capital costs of building the power station in the first place, with an engineering inspection to assess likely future plant life, performance and maintenance and overhaul costs, which would be reflected in the value.
16. **Early termination of the PPA**

The situation where the PPA is terminated early is even more difficult, because the generator will not yet have earned the expected revenues, and similarly, the power purchaser will be deprived of the benefit of the promised flow of power at the contractual price so both parties are likely to be dissatisfied. Also the power station without a PPA will be very vulnerable for all the reasons stated above. These problems are made even more complex if, as is generally the case with independent power projects that have long term PPAs, the power station is built using third party debt finance. This is because lenders will have insisted on additional protections in the case of early termination, before they would provide the necessary finance. The solutions that tend to be agreed are driven by the reasons for the termination, as discussed below.

16.1 **Termination for power purchaser breach or political force majeure**

If the termination occurred because of a breach by the power purchaser, or its insolvency, the generator will expect to have a claim for a termination payment that enables it to repay outstanding project debt\(^{58}\), that repays shareholder equity\(^{59}\) and that compensates it for the net present value of the equity returns\(^{60}\) it would have made if the PPA had continued. The same applies if the PPA is terminated due to prolonged political force majeure\(^{61}\) or other factors that are the power purchaser’s fault or where the PPA attributes that risk to the power purchaser.

In jurisdictions where, as with most developing economies, there is not yet a reliable market for the output of the power station after termination of the PPA, and where the main potential purchaser of power is likely to be the utility itself, the power station is usually sold to the utility as part of the termination arrangements; and the element of compensation mentioned above is in effect reflected in the price of that transfer. The PPA may also provide expressly that the termination payment must be sufficient to repay the generator’s outstanding debt finance\(^{62}\) on the power station, if it is financed with limited recourse debt; though the amounts should in principle be sufficient even if this is not actually stated\(^{63}\).

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58 This would also include the potentially substantial break costs incurred by the project company by way of termination payments when the project company has to terminate long-term interest rate hedging contracts which are no longer needed if the project debt is repaid to lenders.

59 Shareholder equity is usually defined to include shareholder funding provided by way of loans that are subordinated to project finance debt, as shareholders often fund most of their equity in this way as interest and loan repayments can be made without having to comply with any statutory restrictions that would apply to shares before dividends could be declared or share capital could be repaid. There can also be tax advantages depending on the jurisdictions concerned.

60 Some countries have traditionally used formulae that repay original unrecovered equity (at times, even if the power station was underperforming) but provide no additional element to compensate for lost future returns. A more recent trend is for power purchasers to try to limit the period for which lost returns are compensated, on the basis that investors should be able to redeploy their capital within a limited number of years.

61 In some cases, the compensation for political force majeure is paid directly by the state under an implementation or government support agreement, not under the PPA. This obviously is better from the power purchaser’s perspective.

62 This should also include the costs of breaking and hedging commitments that the project company has undertaken in connection with the financing.

63 The main factors which could lead to a termination payment not enabling the generator to repay outstanding debt finance would be if the power station had in some way failed to meet its other targets or had encountered other cost overruns. In cases of political force majeure, there may however be reductions in revenue and increased costs that could worsen the situation.
16.2 Termination for the generator’s breach

If a long-term PPA is being terminated due to unremedied generator’s breach, rather than a power purchaser’s breach, the outcome that is normally agreed is very different. The power purchaser’s losses may be very high, if the power price is favourable compared with the cost of obtaining alternative supplies. In addition, the power purchaser may lose revenue from lost sales to consumers, if there is a period when no alternative power is available. The loss to the economy of the country is even higher. However, all these losses tend not to be recoverable as agreements with consumers will normally cap liability and exclude liability for consequential losses and loss of profit.

In any event the generator would probably be unable to meet liabilities of this size, even if liability were not excluded, particularly if it is a single purpose vehicle which only owns one power station and is predominantly financed with limited recourse debt. Even generators that have a portfolio of power stations which enable them to spread risk would not usually accept uncapped liability for the replacement cost of power. They would also not accept liability for additional loss of profit on sales that the power purchaser would have made to customers but was unable to undertake.

The main debate on termination for generator’s breach of a long-term PPA therefore focusses on whether there should be any termination payment at all and, if the power station is sold as part of the arrangements, how that termination payment relates to the price for that sale. Where there is not yet a reliable market for the output of the power station after termination of the PPA, the generator and its lenders will at the outset normally insist that if the PPA is terminated, there is a sale of the power station to the utility on an agreed price formula. Otherwise, the PPA’s termination would make the power station a stranded asset and they would face the risk of losing the entire value of the power station just because of one material breach of the PPA. This very prospect would also have an unwanted destabilising influence on the contract as a whole, as it would give the power purchaser an incentive to exercise termination rights just in order to make this windfall gain, rather than to keep the contract in place. So, a suitable payment structure on termination for generator’s breach is an important element in establishing a sustainable basis for the power station to be built and operated as an independent power project.

The exact form the termination payment structure takes varies. A typical formula for a project with limited recourse debt would be that the power purchaser terminates the PPA and acquires the power station, but still has to pay off all or at least most of the outstanding project finance debt. This means that the shareholders in the generator project company would lose all their equity, but that the finance providers are substantially protected.

For much of the project life the debt component will be relatively high and will be the dominant factor affecting the termination payment regime. A power purchaser will only want to make this termination payment, if the power station is still capable of generating electricity at reasonable levels of efficiency and reliability, because then it in effect obtains a good power station at a reduced cost. If the power station has been performing below the

64 There are some exceptions in developed economies with liquid spot markets where replacement fuel can be sourced and where PPAs take on the characteristics of hedging contracts or swaps.

65 Of course, in power projects that are project financed, lenders will also have a direct contractual “step in right” which enables them to make the power purchaser suspend any termination for a stated period to allow the lenders to try and remedy the generator’s breach of the PPA and keep the PPA in place. Termination and termination payments would not actually take effect if the lenders’ step-in right is exercised and the situation is successfully resolved.

66 Typically, debt will finance 80% or more of the capital costs of building the power station in a project financed power project, and full repayment of principal is only achieved late in the life of the PPA.
anticipated contractual levels, the power purchaser may seek an adjustment to the formula that determines the termination payment.

In the latter stages of a PPA, project finance debt should have been repaid and most of the tariff payments under the PPA will be used to pay equity its anticipated return. Power purchasers are much more likely to terminate at this stage because they no longer have to contend with the debt-based price floor, and with the complications of taking hostile action against potentially influential lenders. For this reason, equity investors will, at the outset, typically seek another element in the termination payment formula that protects them, typically by saying that the transfer price should be the market price of the power station less a stated percentage discount to reflect the fact that the generating company was in breach. Market value would be calculated on the basis described above, which assumes a willing buyer and seller rather than a “fire-sale” of a stranded asset. An independent expert would resolve any disputes in applying the method of valuation.

16.3 Termination for prolonged force majeure

If termination arises for prolonged ordinary force majeure, the termination payment regime is normally set at a level between the payments due for breach by the generator and for breach by the power purchaser, though exact formulations vary even more than in the case of breach. Much depends on the type of force majeure involved and its consequences – particularly as regards equity, as the fate of the power station depends largely on how the balance between insurance proceeds and reinstatement costs works out. Most cases of short-term force majeure will be rectified within the cure period, so the focus is on events where the power station is destroyed or seriously damaged.

Lenders will have taken security over available insurance proceeds. If there is any doubt about the ability or economic viability of rebuilding the power station and resuming performance, lenders may well elect to apply insurance proceeds towards repaying outstanding debt and recover any shortfall from the PPA termination payment if, as they would expect, it contains a floor equal to outstanding debt. In that case, the shareholders will be left with shares in a company which owns a power station that does not work, and which has lost its PPA anyway. Shareholders can then only try to recover the value of the site if they can find a buyer. The power purchaser is unlikely to agree up front to buy the power station even at market value, because the work and risks involved in the process of organising and financing a restoration are unlikely to be attractive. The utility may, however, insist on a right of first refusal over any sale of the company or of the site and a right to purchase it at an independently determined fair market value, if it chooses to do so. Thus, while shareholders and the project company are not at fault, they are very likely to lose out if the power station is destroyed or seriously damaged by force majeure, unless insurance proceeds cover them.

If lenders conclude that it is viable to restore the asset, insurance proceeds will be applied in reinstating the asset. In that case, the lenders and the generator will seek assurances before starting reconstruction that the power purchaser will not terminate the PPA part way through the work. Restoration of the power station should allow the power station to resume operations and start earning revenue again. Whether the reinstated PPA payments would generate enough net revenue to make any payments to shareholders would depend on: how much debt remained outstanding when the event occurred; whether the insurance proceeds were sufficient to fund the restoration works; and whether the generating company held enough business interruption insurance to cover the additional interest and other expenses incurred while the power station was unable to operate. Thus, even when the power station resumes operations, the financial risks, rather than any particular desire to penalize equity, may place equity at risk of serious loss.
Conclusion

In summary, this chapter has shown how the design of long-term PPAs is driven by three key factors: the unique characteristics of electricity as a product; the risks inherent in a long term sale contract where the seller incurs substantial up front capital expenditure building assets that cannot easily be redeployed; and the particular risks of developing power projects in markets where there is only one realistic purchaser – particularly in jurisdictions where it has low creditworthiness and where investors and lenders may perceive a higher risk of government intervention\(^67\) as can be the case in some emerging markets.

We have seen that the main effects of these three factors are as follows. The characteristics of electricity as a product usually leads parties to long term PPAs to adopt a pricing structure that involves a monthly capacity charge that is paid irrespective of actual levels of generation and a variable energy charge that is paid per unit of electricity actually produced in the month. The capacity charge needs to contain various incentives and checks to try and ensure that the power purchaser gets what it has contracted for. The energy charge is supposed only to reflect the fuel costs incurred but has to be adjusted if the power station performs below the required levels of efficiency in converting fuel to electricity. The energy charge may also have to reflect changes in fuel price and underlying agreed long-term minimum fuel purchasing commitments.

The fact that the generator incurs high levels of capital expenditure and debt when constructing the asset but recovers the costs and makes its profit over the life of the asset means that a long-term contract is needed, to guard against the risk of not recovering these costs over time in the market. The duration of the contract means that it has to take account of changes and events that were not reflected in the original pricing and that are not the generator’s responsibility, such as change in law or tax, and ordinary force majeure. It also means that the PPA needs to contain complex termination payment provisions, to protect the parties’ economic positions if the contract ends before its scheduled expiry.

We have also analysed how PPAs tend to reflect the higher risks that can arise in some emerging markets, particularly where the local utility does not have strong creditworthiness; where there are no realistic alternative purchasers as market liberalisation has not been fully implemented; and where the perceived risk of political intervention may be high. This means that a higher level of government support may be required. This can involve government guarantees of utility payment obligations and implementation agreements containing assurances that the government will facilitate the development of the project, will not take action that undermines it and will compensate the project company if political force majeure events adversely affect the project.

The above factors affect contract design in a number of ways. They mean that PPAs need to be much more complex and detailed than classic sales contracts so that these risks can be fully addressed. They also mean that successfully negotiated PPAs, while varying in form and in detail, tend to produce relatively similar overall results as they will only get signed and financed, if they fit within a range of risk allocations and protections that have come to be regarded as acceptable international market practice – a “bankable” PPA is a key element of a successful project.

This similarity in outcomes should not, however, necessarily be regarded as an indication that all is well. One of the biggest problems in getting power projects successfully implemented in countries that desperately need the additional power they can provide

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\(^{67}\) Another concern is the perceived risk of government or the relevant state-owned company not fulfilling other commitments, for example on the construction of transmission lines.
comes from the time taken in reaching agreement on the terms of PPAs and the other key risk allocations in the project and the risk of negotiations breaking down. For every successfully developed project there are many more projects that would have made very good economic sense, but that have not materialized due to failings in the development and negotiation process. Clear discussion of the reasons why PPAs are designed in a particular way is therefore essential to justify the appropriateness of the proposed risk allocation as the power purchaser and host country representatives need to be able to benchmark developers' and lenders' requests against best international practice. Indeed, the ability of all parties to conduct these negotiations in a way that establishes a balanced outcome without undue delay is a key factor in successfully progressing the economic development of the countries involved and failure to achieve this effectively has a significant opportunity cost for all those involved.

Despite these important challenges, a striking feature of long term PPAs is how widespread they have become in the last three decades or so, across a wide range of jurisdictions in developed and, particularly, developing markets. From a legal perspective, they are a particularly interesting example of how a new legal product was created in a sector of the economy that was previously administered by government; and of how it was rapidly transposed and applied in a relatively consistent way in a wide variety of cultures, jurisdictions and legal traditions, as power project developers, governments, financiers and their lawyers used the product as they sought to deploy external capital to develop new power stations in new jurisdictions. The structures which generally emerge from these negotiations are an example of an internationally recognized range of market practice. Following it is not mandatory in any legal sense but doing so is widely acknowledged to be necessary in order to get transactions to a successful conclusion.

Patrick Wallace
Partner, Simmons & Simmons LLP
Visiting Professor of Law, King’s College London

Tel: +44 20 7825 3082
Mob: +44 7712 085 293
E-mail: patrick.wallace@simmons-simmons.com

PPAs were primarily developed in North America and then in the UK when the power markets were liberalised in the late 1980s and early 1990s. They subsequently spread internationally, particularly as developing economies in Asia, Latin America and subsequently Africa adopted private power programmes to help drive economic development.