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Legal Strategies for the Mitigation of Risk for Electricity Infrastructure Projects

Abstract

The world continues to recover from the global financial crisis of 2007-2009 and consequently project risk continues to be a key concern for lawyers. This is in particular evident in the energy sector where there is a significant need to finance energy projects. This paper focuses on electricity generating infrastructure where estimates of a minimum of \$10 trillion in investment is needed by 2040. Lawyers need to play a role in reducing the risk for these projects and this article examines legal strategies for the mitigation of risk for energy infrastructure projects with a focus on electricity projects. The paper assesses risk for project finance in terms of liberalised and non-liberalised electricity markets, and also from a developed and developing world perspective. Further, the paper notes that energy law theory states that the need for energy infrastructure is a key driver of energy law and policy development in the world at this moment. And finally, it is acknowledged that while project finance has been a research issue for economists for many years, it is time for lawyers to evaluate how they also can mitigate risk for project finance for energy infrastructure projects.

Keywords: Project Finance; Market Risk; Electricity Projects; Liberalised electricity markets; evolution of energy law

1. Introduction: What is Market Risk?

The energy sector international is in an on-going phase of growth and this is set to continue. The International Energy Agency in their latest report state that \$44 trillion is needed for investment in energy infrastructure assets with 60% of this on electricity generating assets (including both fossil fuel and low-carbon energy infrastructure, and for mining the energy sources for use).¹ Bloomberg's annual report states that \$10.2 million is needed for new electricity generating infrastructure. These amounts are significant but it must be remembered that they are anticipated. This article aims to highlight some of the legal strategies to reduce risk in project development and ensure that investment can occur.² Indeed there is widespread opinion that investment decisions will be driven by the extent to which market risk can be mitigated.³

Market risk refers to the range of risks which a business enterprise may be exposed to as a result of operating in a competitive, market-based economy. In this paper energy infrastructure projects are the focus of the examination into the risk in the development of these projects; the focus is in particular on the development of electricity generating projects (or as referred to also 'power projects'). For a power project, these risks primarily comprise diminishing demand for the power, whether as a result of a cross-market reduction in demand (e.g. through increased energy efficiency) or as a result of increased supply; and corresponding fluctuations in the market price for power, each as affected by regulatory structures and rules which affect the way in which a power project interacts with the market.

For investors in power projects, and their professional advisers alike, an understanding of market-risk is important for making investment decisions and implementing corporate and contractual structures to mitigate market risk to protect investments.⁴ Conventional wisdom suggests that, in the absence of understanding, and mitigation of, risk, investors will keep their money at home even when they could earn more on it abroad.⁵ In the event that investment flow is inhibited due to the prevalent market risks, development, modernisation, and access to basic amenities will be adversely affected.⁶

It follows that market risk is a function of the market in which a particular project operates. Generators operate predominantly in the wholesale markets, in which electricity suppliers

¹ International Energy Agency. 2016. World Energy Outlook 2016. Paris, France: OECD/NEA.

² Bloomberg New Energy Finance. 2017. New Energy Outlook 2017: Long-term projections of the global energy sector. Executive Summary. Available at: { HYPERLINK "<http://www.bloomberg.com/company/new-energy-outlook/>" } (last accessed September 2017).

³ The electricity sector leaped ahead of the fossil fuel supply sector to become the largest recipient of energy investments in 2016 for the first time ever. See International Energy Agency, *World Energy Investment* (IEA, 2017).

⁴ See Surya P Subedi, *International Investment Law: Reconciling Policy and Principle* (2nd Edition, Hart Publishing, 2012) 167. In view of the increasing risks faced by highly leveraged project finance transactions, it is important to highlight that investment contracts, especially those relating to infrastructure projects, often provide for higher levels of protection to investors than typical commercial contracts; Also see Arghyrios A. Fatouros, *Government Guarantees to Foreign Investors* (Columbia University Press, 1962). Understanding risk is predicated on the assumption that by mapping out risk, the prospects of any unfavorable consequences is eliminated, and dangers of uncertainty and instability are recognised.

⁵ Marina Van Neumann Whitman, *Government Risk Sharing in Foreign Investment* (Princeton University Press, 1965).

⁶ Paola Morales Torrado, 'Political Risk Insurance and Breach of Contract Coverage: How the Intervention of Domestic Courts May Prevent Investors from Claiming Insurance' (2005) 17 PACE Int'l L.Rev.301.

purchase the electricity which they sell on to end-users. However, the nature of wholesale electricity markets themselves differ from one jurisdiction to another.⁷ Specifically, the scope and nature of the wholesale electricity market in any jurisdiction, indeed the very existence of a wholesale market, is dependent on the extent to which the relevant jurisdiction has embarked on so-called ‘liberalisation’ of its electricity industry. Throughout history infrastructure projects, including energy, have utilised private finance.⁸ However, in the post-war eras of the early to mid-twentieth century, most countries favoured state-ownership of key industries, with energy a prime example. Electricity markets were characterised by governmental bodies or vertically-integrated utilities enjoying monopolies over the ownership and operation of generation, transmission and distribution infrastructure.

Today, many developing countries today still maintain market structures which closely resemble this traditional approach. Meanwhile, the liberalised electricity markets which many developed economies have moved toward over the past thirty years are characterised by the unbundling of generation, transmission and distribution and the opening up of markets to new entrants and competitive trading⁹. This reflects energy law theory which demonstrates the different stages of energy law and how energy law has been influenced by different drivers.¹⁰ According to the theory, economics (i.e. such as liberalisation policies) have become less influential in new energy law and policy development while the demand for new energy infrastructure has increased. It highlights that the need for new energy infrastructure across the world is a key focus for legal change in the energy sector. It is evident here in relation to the mitigation strategies to reduce risk that are outlined in the following sections, and it is clear that energy infrastructure is a key driver of energy law development at this moment.

This paper seeks to provide an overview of how market risk manifests itself across different market structures, and how energy law can contribute to mitigation strategies vary based on the prevailing framework. In economics literature, risk and finance is an important and growing area, and there is a need for lawyers, both practitioners and academics to engage more in this area. This is particularly important in relation to energy considering the aforementioned investment figures for new electricity generating infrastructure internationally. This paper has the principle aim of demonstrating law’s contribution to strategies for the mitigation of risk for electricity infrastructure projects and aims to develop the academic literature in this area with a practitioner perspective. The paper has the following structure. In section two it contrasts the dynamics of non-liberalised and liberalised electricity markets, using Great Britain as the primary reference for liberalised market structures.¹¹ Section three outlines the relevance of market risk on power project financing and investment decisions. Section four examines how investors mitigate, or get comfortable

⁷ Edward R. Yescombe, *Principles of Project Finance* (2nd Edition, Academic Press, 2013).

⁸ Please see Richard A. Brealey, Ian A. Cooper, and Micheal A. Habib, ‘Using Project Finance to Fund Infrastructure Investments’ (1996) *Journal of Applied Corporate Finance* 9, 25-38.

⁹ In Europe, there has been a move away from using the term ‘deregulated’ (which was often used synonymously with the term ‘liberalised’) in acknowledgement that the process of electricity market liberalisation is inherently based on regulation and regulated structures, albeit that it may result in less regulation in areas such as price controls.

¹⁰ Such drivers of energy law are stated as: safety; security; economics; infrastructure; and justice. See: (1) Heffron, R. J. and Talus. K. 2016. *The Evolution of Energy Law and Energy Jurisprudence: Insights for Energy Analysts and Researchers*. *Energy Research and Social Science*, 19, 1-10; and (2) Heffron. R. J. 2015. *Energy Law*. Roundhall, Thomson Reuters: Dublin, Ireland.

¹¹ Northern Ireland has separate energy market structures from the rest of the United Kingdom (i.e. Great Britain) due to its geographical location and now devolved government.

with, market risk across different market structures through their legal rights, whether under private-law contracts or through the relevant regulatory framework and market arrangements.

2. Electricity Market Structures

The electricity industry can be divided into three principal components: (a) generation, (b) transmission, and (c) distribution.¹² Transmission and distribution, which concern the physical movement of electrical energy from generation to load (consumption), are conventionally perceived as ‘natural monopolies’ in that they provide a single, harmonious set of infrastructure which best serves the market as a whole.¹³ Accordingly, whilst many liberalised electricity markets have undergone a process of ‘unbundling’ (i.e. the separation of transmission, distribution and generation into separate and distinct businesses), most of the true liberalisation, such as the deregulation of price controls, minimisation of subsidies and progression toward an open competitive market, has occurred in respect of generation alone.¹⁴ Therefore, in this paper, a reference to liberalised electricity or energy markets should be taken as referring to a liberalised market for wholesale electricity.

Non-liberalised electricity markets can be broadly categorised as falling into one of the following three models:

(i) Full Vertical Integration:

Full vertical integration is characterised by a single entity, either state-owned or privately owned but state-regulated, having a monopoly over the market as a whole and owning and operating all generation, transmission and distribution assets.¹⁵ This market structure does not feature a wholesale electricity market component – the sole utility company owns all the generating facilities and therefore does not procure power from independent generators in order to meet the customer demands in its retail business.¹⁶ The tariffs charged by the utility to the end-users are typically regulated

¹² For a detailed discussion on the components within the electricity cycle please see H. Lee Willis, *Power Distribution Planning Reference Book* (2nd Edition, Marcel Dekker, Inc, 2004) 1. Note also that the accelerating expansion in electricity storage technology suggests that storage may soon emerge as a new and distinct component of the electricity industry.

¹³ See Darryl R. Biggar, Mohammed Reza Hesamzadeh, *The Economics of Electricity Markets* (1st Edition, Wiley, 2014), 73 – 92.

¹⁴ Please see Luis Andres, Jose Luis Guasch and Sebastian Lopez Azumendi, *Regulatory Governance and Sector Performance: Methodology and Evaluation for Electricity Distribution in Latin America* (The World Bank Publication, January 2008). It is interesting to note that despite liberalisation of distribution companies, the lack of independence, transparency and accountability has meant that the liberalisation programmes have not had a positive affect on the entire scheme of deregulation.

¹⁵ It is interesting to note that full vertical integration is considered to be an investment deterrent. Please see David Buchan, ‘Crusading against vertical integration’ (September 2007) Oxford Energy Comment <<https://www.oxfordenergy.org/wpcms/wp-content/uploads/2011/01/Sept2007-VerticalIntegration-DavidBuchan.pdf>> Accessed 06 August 2017. Buchan submits that ‘far more LNG terminals are being built in states that have unbundled their gas networks. However, Buchan argues that there is no scientific evidence to suggest this. He uses United Kingdom as an example where he submits, relying on Philip Wright (Sheffield University) that investment in transmission, as distinct from low-voltage and low-pressure distribution, actually declined in real terms after unbundling’.

¹⁶ The primary narrative against vertical integration is predicated on the thesis that central influence paves way for inefficiency, corruption, and lack of transparency. Unbundling these entities lead to transformation from inefficient state controlled monopoly to a competitive, market-driven system. Please see European Bank for

(and therefore set or controlled by the host government) and may not reflect the investment and operating costs of the utility, therefore state subsidies are often required to plug the funding gap. International investors rarely feature in this market structure.

(ii) Single Buyer:

A single buyer market shares many features with full vertical integration – a single utility company (again, often state-owned or privately owned but regulated) has the sole responsibility for ensuring sufficient generation capacity exists to meet the demands of end customers. The utility company may also have responsibility for ownership and operation of the transmission and distribution networks. The distinguishing feature is that the single buyer may purchase electricity from independent generators in the wholesale market, rather than or in addition to owning its own generation facilities. End-users tariffs are usually regulated and wholesale tariffs, whilst usually agreed in long-term contracts with independent generators, will typically be subject to some level of state-oversight or approval. This model is commonly found in developing countries across Africa and Asia and often represents the first step towards liberalisation.

(iii) Regional Monopolies:

A third model involves the granting of local monopolies to utility companies who purchase electricity from generators in the wholesale markets for on-selling to their customers. This model was common across Europe as an early form of liberalisation, but has since given way to ‘full’ liberalisation. However, the regional monopoly model is still prominent in countries such as the USA and Japan. The tariffs charged by utility companies to their end customers are regulated but wholesale tariffs are usually determined by the market. From the generator perspective, the market operates in a similar way to fully liberalised markets albeit that the pool of customers is, at least theoretically, likely to be smaller.

In comparison to the above three examples of non-liberalised electricity market, liberalised electricity markets work differently. In fully liberalised markets any business can, in principle, establish itself as a generator or wholesale purchaser of electricity and trade freely with other market participants. A market participant will typically require a licence, issued by a regulator, to lawfully perform the functions of a generator or supplier in the market, but the individual entity’s ability to enter the market and perform such functions will be based solely on its ability to fulfil licensing criteria and not as a result of market design. This model commonly appears across Europe, driven by the 1986 common energy policy of the European Council, which set out to build a competitive, sustainable and secure energy system for the benefit of all European stakeholders¹⁷ and resulted in three subsequent ‘energy packages’ in 1996, 2003 and 2009.

Armenia, Georgia, Ukraine and Moldova provide recent examples of unbundling processes. Moldova in particular has benefited from such process. In the 1990s, utilities in Moldova suffered poor cash collections and commercial losses. As a result of unbundling, privatisation

Reconstruction and Development, *Power Sector Regulatory Reform in the Transition Economies: Progress and Lessons Learned* (Working Paper No. 78, February 2003).

¹⁷ See Council Resolution of 16 September 1986 concerning new Community energy policies for 1995 and convergence of the policies of the Member States (O.J. C 241, 25/09/1986)

and industry restructure Moldova has been able to improve its electricity market.¹⁸ However, there are examples where unbundling processes have not affected the performance of the country. For example, after consultation with the Asian Development Bank and the World Bank, Pakistan underwent a major reform in its electricity sector through the Energy Sector Restructuring Program (ESRP) in 1998.¹⁹ Originally, Pakistan's power sector was organised into two state-owned, vertically integrated utilities namely, the Karachi Electric Supply Company (KESC) and the Water and Power Development Authority (WAPDA).²⁰ As part of the ESRP's implementation plan, WAPDA was unbundled into eight different distribution utilities, three generation companies (GENCOs), and the National Transmission and Distribution Company (NTDC). However, despite pressure from multilateral bodies Pakistan has failed to privatise these unbundled entities.²¹ This is primarily because the process of privatisation is fraught with legal and political implications; both of which are undesirable for countries with volatile investment regimes, and incumbent market risk.

Great Britain has, perhaps, been the forerunner of electricity market liberalisation, which began with the passing of the Electricity Act 1989 and, in the same year, the privatisation of the electricity markets. From 1989 onwards Great Britain continued to implement liberalisation measures ultimately leading to the unbundling of the transmission and distribution networks from the wholesale and retail markets and the alleviation of price controls in such markets.²² In practice, Great Britain needed little structural reform to implement the EU's energy packages because it had already implemented similar liberalisation measures of its own initiative.²³

In 2016, nearly two-thirds of global investment in power generation and networks took place in countries with single-buyer or vertically integrated systems. However, as outlined in International Energy Agency's report, there is a likelihood that there will be a transition from single-buyer model to open wholesale markets and retail price competition, creating opportunities for new players.²⁴ Recently, countries like China, Japan, Mexico and Korea, which collectively contribute 40% of global investment have shifted their focus to reforms in the electricity sector.²⁵

¹⁸ Please see European Bank for Reconstruction and Development, *Power Sector Regulatory Reform in the Transition Economies: Progress and Lessons Learned* (Working Paper No. 78, February 2003).

¹⁹ Please see Asian Development Bank, *Pakistan: Energy Sector Restructuring Program* (Performance Evaluation Report, February 2014) <www.adb.org/documents/Pakistan-energy-sector-restructuring-program-0> Accessed on 08 August 2017.

²⁰ Please see Robert M. Hathaway, Bhumi Muchhala, Michael Kugelman, *Fueling the Future: Meeting Pakistan's Energy Needs in the 21st Century* (Woodrow Wilson International Centre for Scholars, March 2007).

²¹ Nargis Sethi, 'Power Sector Reforms in Pakistan's Energy Crisis and Ways Forward' in Michael Kugelman (ed.), *Pakistan's Interminable Energy Crisis: Is There Any Way Out?* (Woodrow Wilson International Centre for Scholars, 2015).

²² See David Newbery, 'Electricity Liberalisation in Britain: The Quest for a Satisfactory Wholesale Market Design' (2005) *The Energy Journal* 43. Also see David Newbery and Michael Pollitt, 'The Restructuring and Privatisation of the CEGB-Was it worth it' (1997) *Journal of Industrial Economics*. XLV (31: 269:303). Newbery and Pollitt submit that privatisation and restructuring the electricity market meant that costs were permanently six percent lower than under the counterfactual continued public ownership.

²³ The wider trend of liberalisation in the European Union is predicated on the withdrawal of the state and its limitation in matters involving infrastructure. However, the trend of liberalisation is not the same as achieving an integrated European market, as some might believe. For a detailed discussion see Tooraj Jamasb and Michael Pollitt, 'Electricity Market Reform in the European Union: Review of Progress' (2005) *The Energy Journal* 11.

²⁴ See International Energy Agency, *World Energy Investment* (IEA, 2017).

²⁵ It is interesting to note that there is a widespread reform underway in emerging and developing economies. Japan for example has introduced a full liberalisation model of the retail market. The reform aims to eliminate

3. Financing and Bankability

Developers of independent power projects often wish to utilise project finance - a method of raising funds on a limited-, or non-, recourse basis, for developing a capital-intensive infrastructure project wherein repayment of the debt is entirely dependent on the internally generated cash flows of the project.²⁶ Historically, project finance has been used in sectors requiring large capital expenditures, that have long-lived assets, and that require long periods to amortise investment costs and generate required rates of returns for both the creditors and the sponsors.²⁷

Project-finance structuring typically requires a special-purpose company to own and operate the financed asset (i.e. a power station) as its sole business purpose. The project under development will constitute the only source of revenue available to the project owner with which to repay project debt.²⁸ Quintessentially, from the investors' perspective, one of the key advantages of using project finance is that it allows the allocation of specific project risks to the project itself rather than the investors' balance-sheet.²⁹ However, a project's ability to achieve forecasted revenues is directly affected by market risk. If a power project fails to yield anticipated cash-flows then, in absence of recourse to the project's ultimate owners, the project risks not meeting debt service commitments and falling into default.

Lenders in a project finance context require an expansive security package and, with that, have a range of options available to them to protect or recover their investment should a borrower fall into default.³⁰ In practice, however, lenders know that if a power project experiences a diminution in cash-flows as a result of market risk factors, the enforcement of security of itself is unlikely enhance their repayment prospects.³¹ Therefore, prior to making

boundaries for vertically integrated, regional electricity companies (EPCOs) and opens their markets to new entrants. Another example is Mexico. Mexico's Comision Federal de Electricidad, a state-owned vertically integrated utility (VIU), is being restructured in order to unbundle its generation and networks and spreading its assets among new companies. See International Energy Agency, *World Energy Investment* (IEA, 2017).

²⁶ See Emanuele Rossi and Rok Stepic, *Infrastructure Project Finance and Project Bonds in Europe* (Palgrave Macmillan, 2015).

²⁷ Antonio Estache and John Strong, 'The Risk The Fall, and...the Emerging Recovery of Project Finance in Transport' (July 2000) World Bank Policy Research Working Paper No. 2385.

²⁸ See Richard A Brealey, Ian A. Cooper and Michael A. Habib, 'Using Project Finance to Fund Infrastructure Investments' (1996) *Journal of Applied Corporate Finance* 9, 25-38. It is interesting to note Nevitt and Fabozzi's submission. They argue that project finance is financing of a particular economic unit in which a lender is satisfied to look initially to the cash flows and earnings of that economic unit. Please see Peter K. Nevitt and Frank J. Fabozzi, *Project Financing* (7th Edition, Euromoney Book, 2004).

²⁹ Richard A. Brealey, Ian A. Cooper and Michael A. Habib, 'Using Project Finance to Fund Infrastructure Investment' (1996) *Journal of Applied Corporate Finance* 9, 25-38.

³⁰ Typical security packages will cover the shares in the project company (and any specially established holding companies), key project contracts, bonds and guarantees, bank accounts, project insurances, and physical property, in addition to 'direct agreements' in relation to key contracts (such as PPAs) which allow lenders to step-in and attempt to solve issues occurring in relation to such contracts. However, in a project finance context the general understanding is that first, that creditors share much of the venture's business risk and, second, that funding is obtained strictly for the project itself without an expectation that the corporate or government sponsor will co-insure the project debt, at least partially. Please see Stefanie Kleimeier and William L. Megginson, 'An Empirical Analysis of Limited Recourse Project Finance' (July 2001). Univeristy of Oklahoma, Michel F. Price College of Business Working Paper Series. Available at SSRN: <http://ssrn.com/abstract=283969>.

³¹ Various measures of security, contractual arrangements, which may vary over time in line with the progress of a project, is designed to allocate the various risks presented by the project to those parties that are best able to control and appraise those risks. However, in view of market risk in line with the decrease in demand or lack of

debt available, lenders will require assurances that a project has the ability to earn sufficient revenues over the tenor of the debt to meet debt service and operating costs, irrespective of the prevailing market conditions.³²

The identification of market risk mitigation strategies is therefore an important constituent of bankability assessments – bread and butter to project finance departments at major international law firms and financial institutions. Even project developers who finance new projects from their own balance sheets, and therefore do not rely on third party debt, will undertake robust financial modelling to ensure that a project has the ability to meet expected levels of return on equity before developers make their final investment decision.³³

4. Market Risk Mitigation

As outlined in the section *Electricity Market Structures*, non-liberalised energy markets tend to fall into three broad categories. Of these, the single buyer paradigm provides the most useful reference point for comparative analysis, as it represents an intermediate step toward a mature, liberalised energy market. This structure is common to many developing countries, and is therefore well understood by sponsors, lenders, and their legal advisers.

4.1. Non-Liberalised Markets

In a single-buyer market, the nature of the market defines the nature of the market risk – with only one potential customer, power project owners are fully exposed to the fluctuations in demand from that customer, the credit risk of that customer and the consequences of the loss of that customer. Investors in new generation facilities have traditionally sought to protect their investment, and give comfort to their lenders, by entering into long-term contracts with utility company purchasers, known as power purchase agreements (PPAs), which lock-in demand at fixed prices.³⁴ Project owners can take advantage of the bilateral

infrastructure there is little that these contractual arrangements can provide to mitigate risk. Please see Richard A. Brealey, Ian A. Cooper, and Michael A. Habib, ‘Using Project Finance to Fund Infrastructure Investment’ (1996) *Journal of Applied Corporate Finance* 9, 25-38.

³² In this context, long term, fixed-price PPAs can be considered stand-alone guarantees. They act as an assurance that the off-taking body will off-take an agreed sum of electricity from the project company.

³³ There are, however increasing concerns regarding the due diligence exercises involved in such projects. Especially from a developing country context, it is likely that the off-taker and subsequently the state, due to an unliberalised model are unable to meet payments under the PPAs. This is a common instance in India, Pakistan, Nigeria and other emerging, developing economies. Please see Musadil Malik, ‘Pakistan’s energy crisis: Challenges, Principles, and Strategies’, in Michael Kugelman (ed.), *Pakistan’s Interminable Energy Crisis: Is there any way out?* (Woodrow Wilson International Centre for Scholars, 2015); Planning Commission of Pakistan and USAID, *The Causes and Impacts of Power Sector Circular Debt in Pakistan* (March 2013) <http://pdf.usaid.gov/pdf_docs/PA00KPHC.pdf> Accessed on 4 August 2017.

³⁴ In order to attract private capital, developers and raise debt finance in emerging markets, PPAs are offered for 20-25 years as a way to reduce risks of revenues falling short of that required to recover the investment.

Since electricity generation is carried out through a newly incorporated special-purpose entity, it is important that there are robust measures of security. PPAs are a form of security measure especially in the context of a newly incorporated entity. They provide a robust measure of security and a guarantee that payments will be made by the off-taking body as debt. Moreover, in view of PPAs separate incorporation it is therefore necessary and important to allow the sponsors to set up a capital structure of high-debt, syndicated lending that is rigid and tied to a single-purpose capital test. Please see Rajeev J Sawant, ‘The Economics of Large-scale Infrastructure FDI: The Case of Project Finance’ (August, 2010) *Journal of International Business Studies*, Vol. 41, No. 6, pp.

structure and negotiate carefully drafted PPAs which dampen market-risk factors. As such, the primary strategy for mitigating market risk in single-buyer markets is through the enforcement of private-law rights and obligations. The enforceability of private law contractual rights and obligations will be determined in accordance with the governing law of the relevant contract – the below analysis is based on English law. In single-buyer markets, key PPA features include the following:

(i) *Tariff Structure:*

For dispatchable technologies (i.e. those facilities which the operator may dispatch to order, such as thermal facilities or storage hydropower), this will usually take the form of a capacity-based PPA under which the off-taker undertakes either to ‘take-or-pay’ for designated minimum volumes of electricity or to pay a fee for the technical availability of the relevant generation facility, in each case regardless of the actual dispatched volumes. Take-or-pay clauses were at one point considered compensatory in nature, akin to a liquidated damages clauses (which provide a pre-determined measure of damages for a stipulated breach of contract), and therefore subject to English common law of penalties³⁵. This led to concerns over the enforceability of take-or-pay clauses which, in part, led to the emergence of ‘capacity payments’ as an alternative contractual mechanism to achieve the same goal. However, in the recent landmark Supreme Court case of *Cavendish Square Holdings BV v Talal El Makdessi*³⁶ the English Supreme Court noted that the law on penalties did not apply to take-or-pay or similar clauses because that law only applies to damages/compensation clauses which constitute a secondary obligation triggered by the breach of a primary obligation – whereas an obligation to pay for a commodity (e.g. electricity) even if not delivered should properly be construed as a ‘contingent primary obligation’ rather than a secondary obligation.

For non-dispatchable technologies (such as intermittent renewables), the PPA may feature an ‘energy only’ tariff under which the off-taker only pays for energy delivered to the grid, coupled with a regulatory or contractual right of ‘priority dispatch’ in which the project owner has a right to put its power on to the grid ahead of conventional generators during any settlement period. In each case, the tariff structures are designed to ensure that the project can yield sufficient revenues through the PPA to enable the project owner, as a minimum, to meet its operating costs and debt service obligations.³⁷

These tariff structures mitigate the risk of insufficient end-user demand and the subsequent non-dispatch of a generating facility; so called ‘dispatch risk’. In non-liberalised markets it make sense for the off-taker to carry the ‘dispatch risk’ because the off-taker, or a closely affiliated entity, will usually perform the role of system operator. In other words, the decision as to whether or not to dispatch a particular facility will rest with the off-taker. Contractual tariff structures of this nature are considered to form part of the fabric of energy industry risk

1036-1055. Also see Philip R. Wood, *International Loans, Bonds, Guarantees, Legal Opinions: The Law and Practice of International Finance Series* (2nd Edition, Sweet and Maxwell, 2007).

³⁵ See *M & J Polymers Limited v Imerys Minerals Limited* (2008) EHC 344 (Comm).

³⁶ 2015 UKSC 76

³⁷ It is interesting to note the various factors that are incorporated in the tariff determination process in order to design a tariff structure. Without limitation, these may include different risk factors such as inflation, exchange rate, demand and fuel prices. For a detailed discussion please see Sudong Ye and Robert L.K.Tiong, ‘Effects of Tariff Design in Risk Management of Privately Financed Infrastructure Projects’ (December 2003) *Journal of Construction Engineering and Management* Vol.129, Issue 6.

allocation in non-liberalised markets.³⁸ In a developing country context, however, there is some evidence to suggest that these investment incentive mechanisms have proved detrimental for the electricity markets. Pakistan's 1994 Power Policy³⁹ was based on a take-or-pay PPA model which had no regard to the actual performance of the electricity generation facility. Since returns were guaranteed for the life of the project, there were no incentives for the project sponsors to create efficient, advanced electricity projects.⁴⁰

(ii) *Fixed Price:*

A fixed, per unit, price often with an index-linked escalation mechanism. This strategy insulates a project developer against fluctuations in the market price for power.

(iii) *'Deemed Energy/Availability' Payments*

So-called 'deemed energy' or 'deemed availability' payments enable the project owner to earn revenue for energy not delivered, or during times of unavailability, where the occurrence of certain events outside its control affect its ability to operate the power plant and earn revenues in the usual way. Such provisions typically provide a project owner with relief for circumstances occurring under the control of a state-owned off-taker (or other state entities), such as political events, or technical issues affecting other aspects of the electricity infrastructure. However, in developing countries, operating single-buyer electricity markets and with an otherwise high risk profile for investors, PPAs may also provide project owners with relief against other events outside the project owner's control (whether or not in the control of the off-taker) including the risk of adverse in situ conditions – such as lack of wind, sun or river flows.

Often, the contractual mechanism underpinning deemed energy payments is a force majeure clause – which provides relief against exceptional events which hinder contractual performance. English law does not recognise the concept of force majeure as a common law principle – its application in any particular case therefore depends on the wording in the applicable contract. PPAs in single-buyer markets often characterise force majeure events as 'political' and 'non-political' – with non-political events entitling a project owner relief from its performance obligations but not deemed energy payments and with political events entitling a project owner to relief from its performance obligations *and* deemed energy payments. Force majeure clauses do not typically face any particularly enforceability issues, provided the drafting is sufficiently certain.

(iv) *Termination Payments*

As the PPA represents the sole route to market, in a single-buyer structure, the early termination of a PPA effectively represents the end of a project's ability to earn a revenue. The project owners cannot sell power to another buyer because the applicable market rules will prohibit them from doing so and, in practice, no other buyers will exist in the market. Assuming a breach of contract caused the termination of a PPA then, in the absence of express provisions in the PPA, some common law damages would likely be available to the

³⁸ Ben Holland, 'Enforceability of take-or-pay provisions in English law contracts-resolved', (2016) *Journal of Energy & Natural Resources Law*. <<http://dx.doi.org/10.1080/02646811.2016.1164554>> Accessed April 2017.

³⁹ Please see Policy Framework and Package of Incentives for Private Sector Power Generation Projects in Pakistan (March, 1994) <<http://www.ppib.gov.pk/Power%20Policy%201994.pdf>> Accessed on 05.08.2017.

⁴⁰ Shannon Grever, 'How to Incentivize Energy Innovation and Efficiency, and Encourage the Rapid Deployment of Affordable Solutions' in Michael Kugelman (ed.), *Pakistan's Interminable Energy Crisis: Is there any way out?* (Wilson Woodrow International Centre for Scholars, 2015).

non-defaulting party. Under English law, damages for breach of contract are intended to put the non-defaulting party in the same position as it would have been in had the breach not occurred. A defaulting party would have no right to recover damages from the non-defaulting party.

However, project finance lenders do not much like to rely on common law damages remedies and in any event would not accept the risk of loss caused by a default of their borrower. As such, PPAs typically provide the project owner with substantial compensation in the event of early termination, even where the termination is due to the default of the project owner. A project will not be financeable unless the lenders are assured that the project-owners have sufficient funds available to repay their debt in full in the event of early termination of the PPA. To achieve this, the project owner recovers termination payments from the off-taker which are sized to cover, as a minimum, full repayment of project debt. Projects are often procured by the utility on a ‘build-own-transfer’ (or ‘BoT’) basis, meaning that upon expiry or termination of the PPA ownership of a power plant transfers to the off-taker, so it receives an asset in return for the termination payment – making it palatable for an off-taker to make substantial termination payment where it is the non-defaulting party⁴¹.

Project owners are able to negotiate PPAs on these terms in non-liberalised markets because such terms are required to attract investment; these projects have only one route to market and investors have limited means of legally mitigating their risk other than through their private law contractual terms rights. The somewhat counter-intuitive outcome is that a less liberalised market structure can result in greater contractual bargaining strength for investors. With such PPA terms available, the key risk in non-liberalised energy markets tends to be the credit profile of the off-taker (*i.e.* the financial capability of the off-taker to honour its contractual commitments) rather than market-risk factors *per se*.

4.2. Liberalised Markets

The situation in liberalised energy markets is noticeably different, and requires investors, lenders and legal advisers to adopt a much broader view. Whereas participants in single-buyer markets can rely on carefully-drafted contractual provisions to mitigate market risk, adapting to the reality of a fully liberalised energy market requires an affinity for the complex web of policy, law and regulation underpinning the market, as well as an economist’s eye for the dynamics which drive risk factors.

Project owners have a range of options for monetising their assets, including selling energy through PPAs, short term bilateral traders (often referred to as ‘over-the-counter’ (“*OTC*”)) and through real-time power exchanges and spot markets. In addition, market balancing and clearing rules offer financial incentives to project owners in certain circumstances and the emergence of markets for capacity-only and ancillary services allow project owners to earn revenue for services other than the delivery of energy alone. Utility companies remain among the largest purchasers of wholesale electricity, but they are not limited in number and freely compete with one and other for end-customer business. Certain liberalised markets have also

⁴¹ In practice, PPA termination payments will typically be tailored to fit a range of termination scenarios including owner default, off-taker default, and non-default termination (e.g. in the case of force majeure), with larger payments available to the project owner where termination is not due to the default of the project owner. As a minimum, however, project finance lenders will require termination payments sufficient to cover repayment of project debt in all scenarios, including project owner default.

recently evolved to allow generators to sell on-grid power directly to large end users, effectively leap-frogging the wholesale market altogether.

These market conditions provide project owners with natural mitigation against certain risks faced in non-liberalised markets, in that a project owner has a much broader range of options for its commercial strategy and a broader pool of customers, meaning the loss of one customer can, theoretically be replaced by a new customer. However, it also means that project owners are less able to secure long-term PPAs and, in any event, PPA terms will not offer the same extent of market risk mitigation as those available in non-liberalised markets.⁴² In this context, key PPA features include the following:

(i) *Tariff Structure:*

PPAs will typically feature an ‘energy only’ tariff under which the off-taker only pays for energy delivered to the grid, for both dispatchable and non-dispatchable technologies. A purchaser of wholesale power will, in most cases, not play a role in system operation or balancing – the purchaser takes power off the grid and pays for it according to its contracted purchasing positions. Therefore, it does not make sense for an off-taker to pay for the technical availability of a generation facility or for energy which it does not consume: that only stands to reason where the off-taker has the responsibility for balancing the grid and has the ability to directly dispatch the relevant power plant. An off-taker may agree to take a fixed portion of the power which a power plant puts on the grid, but the project owner will carry the risk of getting power onto the grid. In a liberalised energy market, shortfalls in the physical delivery of forecasted amounts under a PPA will not usually result in shortfalls in the amount ultimately consumed by the off-taker (or, more accurately, the ‘off-taker’s customers), rather it will mean that the off-taker needs to purchase the additional volumes of power through alternate channels to make up such shortfalls – another reason why an off-taker is very unlikely to agree to pay for any volume of power not actually delivered to the grid.

(ii) *Fixed Price:*

Most PPAs involving some degree of price certainty, as that is one of the key reasons for the parties to enter into a PPA, but in a liberalised electricity market PPA tariffs are often pegged against the prevailing market price rather than fixed on a per unit basis. Such a mechanism allows PPA revenues to fluctuate in accordance with movements in the market price of power, which lessens the mitigation against market risk as compared to an actual fixed price.

(iii) *‘Deemed Energy/Availability’ Payments*

PPA tariffs in liberalised markets tend to work on an energy only basis for the reasons described in the section *Tariff Structure* above. However, in countries which have embarked on market liberalisation but in which state-owned entities remain prominent participants in

⁴² The general perception normative to the debate for liberalised and non-liberalised markets relates to how economically advanced countries compare with developing countries. A developing country experiencing low investment in electricity regime will offer higher returns. However, these returns are cognisant of the risk that the investor bears. Therefore, the terms within a PPA will reflect this risk, in addition to other security measures. These may include take-or-pay provisions or cost plus model. Host states, especially developing countries may issue guarantees. These enable the sponsors to shift the financial risk of a project to one or more third parties. See Peter K. Nevitt and Frank J. Fabozzi, *Project Financing* (7th Edition, Euromoney Book, 2004). Also see Emanuele Rossi and Rok Stepic, *Infrastructure Project Finance and Project Bonds in Europe* (Palgrave MacMillan, 2015); Arghyrios A. Fatouros, *Government Guarantee to Foreign Investors* (Columbia University Press, 1962).

the market (such as in Turkey, where private power plants have a number of routes to market including power exchanges and PPAs but where most off-takers remain either state-owned entities or private entities operating under state control) - private project owners may find some countenance for PPA terms which protect against loss of revenues arising from political circumstances or other circumstances falling within the control of the applicable state-entities.⁴³

(iv) *Buy-Out Payments*

A PPA will not normally provide for compensation covering full project debt repayment in the event of early termination. A power plant may not necessarily contract to sell all of its power to a single off-taker - it may have PPAs with a portfolio of different off-takers or it may elect to sell a portion of its output through a PPA and the remainder OTC or through a power exchange. Even if it has contracted to sell its entire output through a PPA to a single off-taker, the expiry or termination of that PPA does not necessarily signal the end of the commercial life of the relevant power plant – the project owner may be able to find a replacement PPA or move to selling power exclusively OTC or through power exchanges or repositioning itself as a capacity provider.

For these latter reasons, off-takers can rely on an expectation that the market conditions will allow the project owner to mitigate losses through seeking an alternate source of revenue as a means of resisting significant termination payment obligations. However, some termination payments, particularly in the case of an off-taker default, may remain achievable for a project owner – for example, if a project owner suffers loss because the market price for power deteriorates such that, upon termination of a PPA, it cannot achieve the same price in the market as it would have achieved under the PPA for the remainder of the term, then the project owner may have a right at law to recover its loss of revenue in such circumstances and the parties to the PPA may therefore prefer to address that possible scenario at the time of entering into the PPA by liquidating the potential damages in a termination payment mechanism, which commonly occurs.

4.3: Further Issues in Liberalised Markets

For the reasons summarised above, power plant owners in liberalised energy markets tend to experience higher levels of market risk and have less leverage for passing such risk to off-takers through PPAs, when compared to a project owner with a PPA in a non-liberalised energy market. However, on the basis of case-study examples from countries including Armenia, Georgia, Ukraine, Moldova and even India, it can be argued that well regulated, liberalised electricity markets embody self-regulation, and therefore diminish risk - but this hypothesis will require a separate, independent study.⁴⁴

⁴³ See, International Energy Agency, *Energy Policies of IEA Countries (Turkey 2016 Review)* <<https://www.iea.org/publications/freepublications/publication/EnergyPoliciesofIEACountriesTurkey.pdf>> Accessed on 24 August 2017.

⁴⁴ Please see European Bank for Reconstruction and Development, *Power Sector Regulatory Reform in Transition Economies: Progress and Lessons Learned (Working Paper No. 78, February 2003)*. The working paper indicates that the experience in California shows that if generation and transmission costs are not passed down to the consumer, then the financial viability of distribution companies become jeopardised. The solution, namely for the government to subsidise electricity consumption, will often not be an option in many transition economies where government finances is highly constrained.

Structurally, however, liberalised markets present power plant owners with opportunities for mitigating their exposure outside of contractual arrangements with offtakers. The below summarises certain established, and emerging, features of liberalised electricity markets, which serve to mitigate market risk for developers.

(i) Market Structure and Dispatch:

Dispatch is the term used to describe the process of activating generation facilities to deliver power to the grid to ensure the balance of demand and supply at all times within a grid system.

Non-liberalised market structures, such as the single-buyer model, tend to feature relatively unsophisticated central dispatch regimes in which the offtaker, in its capacity as system operator, directly dispatches generation facilities based on its need for power and the methodologies set out in the prevailing grid code and/or market rules. The market structure does not enable a project owner to enter into bilateral contracts with any person other than the single buyer. This exposes the project owner to dispatch-risk, because the project owner has no assurance or control over the dispatch of its power plant and if it is not dispatched by the single-buyer then it cannot sell its power in the market. This illustrates why project owners in non-liberalised energy markets require PPAs which lock-in cash flows through take-or-pay or capacity payment tariffs.

Liberalised energy markets globally have adopted varying approaches to dispatch systems, but in each case offering a lower degree of dispatch risk to project owners than experienced in non-liberalised markets. Certain liberalised markets⁴⁵, such as in Australia and Sweden, feature a central-dispatch system based on a ‘pool’ arrangement. In a pool arrangement, project owners bid into the pool by informing the system operator of prices at which they are prepared to generate or at which they are prepared to reduce generation. The systems operator then performs the role of matching demand and supply in the most efficient way and dispatches generators accordingly, and generators are then usually paid according to a common clearing price rather than the price they actually bid into the pool. Depending on the rules of the particular market, participation in the pool may or may not be mandatory – similarly, trading outside of the pool, through independent bilateral or multilateral arrangements, may or may not be permitted.

Great Britain’s original version of liberalisation utilised a pool and central-dispatch system. However, this was replaced by a self-dispatch regime following the New Energy Trading Arrangements (“*NETA*”) and British Electricity Trading and Transmission Arrangements (“*BETTA*”) reforms, which were implemented through the Utilities Act 2000. *NETA* and *BETTA*, which replaced the previous pool system, permitted forwards and future markets, and short term power changes, for electricity trading.⁴⁶

⁴⁵ It is interesting to note that academic literature finds that ‘effective separation of generation and transmission activities is crucial for achieving competition in wholesale electricity markets. See Paul Joskow, ‘The Difficult Transition in Competitive Electricity Markets in the U.S.’ (2003) Working Paper 2003-008. Center for Energy and Environmental Policy Research, Massachusetts Institute of Technology; Also see David Newbery, ‘Regulatory Challenges in European Electricity Liberalisation’ (2002) Swedish Economic Policy Review 9:9-43.

⁴⁶ For detailed discussion on the vertical separation of generation from transmission and distribution, and creation of a pool, please see Andrew Powell, ‘Trading forward in an imperfect market: The case of electricity in Britain’ (1993) *The Economic Journal*, 103, 444-453.

From a dispatch perspective, the British model allows project owners to freely deliver power to the grid unless the system operator intervenes to curtail generators. Both the right of electricity generators to export power to the grid and the right of the system operator to constrain such exports are found in section 2.3.1 of the Connection and Use of System Code (“*CUSC*”). The CUSC is the contractual framework by which power producers interface with the UK’s transmission system.⁴⁷ Project owners determine whether to dispatch based on the economics of doing so during any particular settlement period (*e.g.* a function of the prevailing operation and maintenance costs, market price, and demand for power) and the project-owners’ contracted positions. Project owners and purchasers then notify the system operator of their contracted positions and the systems operator will typically only intervene to curtail generators if it identifies a material imbalance in the system as a whole for any settlement period – an individual power plant’s imbalances will be addressed through imbalance settlement mechanisms (see section *Balancing Mechanisms* below). The regulatory framework of a particular jurisdiction will determine the dispatch system adopted in that system.

Therefore, in liberalised markets, the dispatch regime enables market activity amongst market participants (willing buyers and willing sellers) either through the creation of a pool in which the dispatch of power plants is determined by market activity occurs or by enabling dispatch to occur according to the bilateral trading of market participants. In each case, in the liberalised markets, power plant operators have an element of control over the dispatch of their power plant through the economic decisions it takes. In a non-liberalised market, a power plant owner has little control over the dispatch of its power plant after it has signed a PPA with the single-buyer.

(ii) Balancing Mechanisms:

Balancing of electricity grids (*i.e.* the real-time and continuous matching of load with supply to ensure stability of the grid) is an essential function of a grid system operator⁴⁸. Imbalances can occur because generators and purchasers deliver, or offtake, more or less power than corresponds to their contracted positions for any settlement period. To manage imbalances a systems operator will, depending on the nature of the imbalance, need to step-in and call additional capacity to make power available or to curtail generators in order to reduce supply. These activities can provide opportunities for generators in liberalised energy markets. For example, Great Britain’s Balancing and Settlement Code (“*BSC*”) allows market participants to submit offers to sell energy to the system and bids to buy energy (which may take the form of voluntary curtailment by decreasing generation) from the system⁴⁹ – in many ways serving as a ‘mini’ pool. In the same way that licensed electricity generators are required to adhere to the CUSC (as described in the above section on Market Structure and Dispatch), Condition 9 of the Standard Conditions of the Electricity Generation Licence operates to make generators party to the BSC Framework Agreement and obligates them to comply with the BSC.

⁴⁷ Section 4 of the Electricity Act 1989 requires most major electricity generators to hold a generation licence, which are issued pursuant to section 6(1)(a). Licensees automatically become party to the CUSC Framework Agreement, and are obligated to comply with the CUSC, by virtue of Condition 19 of the Standard Conditions: Electricity Generation Licence.

⁴⁸ In liberalised markets, system operators perform two principal functions (i) physical balancing of the grid (*e.g.* dispatching and curtailing generation facilities), and (ii) financial settlement of balancing services (*e.g.* levying imbalance charges). In Great Britain, the grid system operator is National Grid.

⁴⁹ Section Q(4) of the BSC describes the bid-offer balancing mechanism .

The BSC's mechanisms provide project owners with opportunities to generate cash flows outside of their contracted positions. The BSC also gives the systems operator the right to levy imbalance charges, known as 'cash-out' payments, where market participants experience imbalances (the French balancing mechanism, *Le dispositif de Programmation et Adjustment*, operates a similar model, as does the Turkish Electricity Market Balancing and Settlement Regulations). For a generator, an imbalance deficit would mean that its contracted volumes (i.e. the volumes which had agreed to deliver pursuant to PPAs, OTC contracts and exchange trading for any settlement period) exceed the amount actually delivered by it for the relevant settlement period whereas the opposite would amount to an imbalance surplus. Participants in surplus receive a cash-out credit whereas participants in deficit incur a cash-out debit, but in either scenario the payments are based on the system operator's balancing costs.

Cash-out payments were calculated to incentivise the participants to balance their positions (i.e. participants' net financial position would have been more favourable had they balanced their contractual positions). This creates a disincentive to 'dump' un-contracted power on to the grid as a means of revenue generation and, some have argued, drove power plant owners to enter into bilateral arrangements.⁵⁰ However, recent reform of the BSC has led to the introduction of a single imbalance payment, meaning a market participant in surplus will receive the same amount, per unit, as a market participant in deficit. According to a 2016 report published by the Competition and Markets Authority, "relying on cash-out as a market of last resort is no longer loss-making by design"⁵¹.

In non-liberalised markets, project owners deliver power according to the dispatch instructions of the system operator – the market arrangements, of themselves, do not enable a project owner to receive an income for electricity which is not dispatched and delivered to the grid.

(iii) Capacity Markets and Ancillary Services:

Liberalised energy markets evolved as 'energy-only' markets, in which project owners earned revenues solely in respect of the power which they produced and deliver to the grid. Economic theory suggests that market forces alone would ensure security of supply in a liberalised energy market because prices would rise in the event of supply shortages, stimulating investment in new capacity. However, a range of regulatory measures aimed at encouraging the proliferation of intermittent renewables and reducing the development of new fossil-fuel facilities⁵² have had unintended consequences for electricity markets, creating a new kind of market risk. For this reason, countries with liberalised energy markets have sought to introduce capacity markets to ensure sufficient generating capacity remains connected and available to react when required.

Capacity markets have taken a number of different manifestation but, as their fundamental objective, they ensure security of supply by paying project owners for available capacity, rather than actual energy output, and by requiring project owners to deliver energy to the grid

⁵⁰ See Darryl R. Biggar, Mohammed Reza Hesamzadeh, *The Economics of Electricity Markets* (1st Edition, Wiley, 2014), 124-125

⁵¹ Energy market investigation, Final report, 24 June 2016 (Appendix 5.1, para. 59) by the Competition and Markets Authority

⁵² In the United Kingdom, the measures include the Climate Change Levy (effectively a tax on carbon emissions), the Emissions Performance Standard (a limit on carbon emissions for new generating facilities), and 'subsidies' for low-carbon technology through Feed-in-Tariffs, Renewable Obligation Certificates and Contracts for Difference.

if required. In this sense, they perform much the same function as capacity-based PPAs often seen in non-liberalised markets. From the investor perspective, capacity markets provide an additional source of revenue and therefore offer a potential hedge against market-risk factors in the energy only markets.

In the United Kingdom, capacity markets were introduced through the Energy Act 2012 (as amended)⁵³ and the Electricity Capacity Regulations 2014 (as amended)⁵⁴ and associated subordinate legislation. The system is administered by a delivery body who procures capacity through auctions in which capacity providers (both generators and providers of demand-side reduction) bid against a demand curve. The winning bidders receive regular capacity payments in return for a commitment to make capacity available to the system when called upon to do so by the systems operator⁵⁵. Like any market, capacity markets themselves experience market-risk and the demand for capacity and the price payable will be determined by the prevailing market conditions and regulatory rules.

Ancillary services are another tool used by systems operators to balance grid systems as well as maintain grid stability. Ancillary services comprise a range of functions which grid operators may require generators to perform – they include function such as holding back reserve capacity (much in the same way as capacity markets, but often over shorter periods) to providing power for grid-restoration purposes in the event of black-outs (often referred to as ‘black-start’ capability) in addition to frequency control activities.

In non-liberalised markets, system generators have often had an obligation under applicable grid codes to provide ancillary services at no cost to the systems operator. Liberalised markets, on the other hand, have seen progression toward the procurement of ancillary services by systems operators from generators. For example, in Austria, system operator Austrian Power Grid has primary responsibility for balancing the grid and runs an electronic tendering platform for weekly procurement of various tranches of capacity reserves, on the basis of a lowest price auction.

In Great Britain, the system operator also awards contracts for the provision of Short Term Operating Reserve (“*STOR*”) following tenders processes run three times per year. Each STOR Framework Agreement, which gives legally binding effect to the STOR Standard Contract Terms, is a bilateral agreement between the system operator and the so-called “*reserve provider*”. So long as the reserve provider is within the BSC rubric, the STOR agreement dovetails with the Code, with contractual instructions given by way of bid-offer acceptance and payments settled through the Balancing Mechanism. Non-BSC reserve providers are instructed and paid via a bespoke despatch system which communicates directly with National Grid’s control room.

STOR contracts work on the same principles as capacity agreements, in that the capacity provider receives regular capacity payments in return for a commitment to make available capacity if called – the key differences being that the system operator, National Grid serves as the counterparty (rather than the capacity market delivery body) and the capacity must be

⁵³ see section 27(Power to make electricity capacity regulations)

⁵⁴ SI 2014 /2043

⁵⁵ Capacity providers will receive payment for delivered energy through their independently contracted positions or through the BSC rather than through the capacity agreement.

made available at shorter notice (twenty minutes as opposed to four hours under capacity agreements).

(iv) Contracts for Difference and Hedging:

A contract for difference (“*CfD*”) is a bilateral contract which allocates to one of the parties to the contract the right to receive payment for the difference between two prices for an underlying asset (one or both of which prices may be variable). CfDs have gained prominence due to Great Britain’s Electricity Market Reform initiative which put CfDs front and centre as the key support mechanism for incentivising investment in low carbon generation assets in Great Britain. Following a consultation process which began in 2010, the modern CfD regime was implemented by Chapter 2 of the Energy Act 2013. The CfD used in Great Britain constitutes an agreement between a project owner, on the one hand, and a government-backed counterparty (the Low Carbon Contracts Company) – under which the project owner receives ‘top-up’ payments from the counterparty where the electricity market price falls below a fixed price stated in the CfD (the ‘strike price’) for any settlement period⁵⁶. Whilst Great Britain’s CfD has as its objective the mitigation of market risk, its primary purpose is to encourage investment in low carbon generation – it is not therefore available to all power plant owners.

However, CfDs are not a new phenomenon in electricity markets – they have been a feature of the Scandinavian ‘Nord Pool’ market since 2000. In the Nord Pool, the CfDs have slightly difference characteristics to the CfDs currently seen in Great Britain – the main differences are that they correspond to the difference between two variable prices (the System Price and the Area Price), as opposed to the British CfD which has only one variable price component, and they are contracts which are traded in their own right (i.e. CfD counterparties agree to take on the risk presented in the contract as a form of investment), as opposed to a structural incentive mechanism as in the case of the British CfD.

The common feature of all CfDs is that they are fundamentally an instrument for hedging against market risk – enabling investors in energy generation assets to make investments, and raise finance, when operating in highly liberalised markets where market risk prevails and fixed-price long term PPAs may not be available. CfDs are not the only mechanism for hedging market risk in liberalised markets; in markets such as Great Britain project owners can sell power OTC in future and forward markets to hedge against market price fluctuations and power plant owners and energy suppliers (i.e. purchasers of wholesale power from project owners) may also enter into CfDs with one and other in order to mutually hedge against the market risk they face on each side of the market.

5. Conclusion

The global energy sector in relation to electricity generating infrastructure is in the midst of a period of rapid growth and change.⁵⁷ There are more than several major issues that are

⁵⁶ Conversely, the CfD requires the project owner to make payments to the counterparty where, in any settlement period, the market price exceeds the strike price.

⁵⁷ See Section one, the introduction, and the reference to the World Energy Outlook 2016 reports which states that \$44 trillion is needed in energy infrastructure investment, with 60% of this related to power generation (including both fossil fuel and low-carbon energy sources).

driving this, and in particular the increasing demand for power, the energy transition that promotes low-carbon electricity, and the need to replace aging electricity assets in many countries. Across the world there continues to be a push for countries to develop liberalised, market-based industries but this has slowed due to the impact of the financial crisis. More important than the economics of liberalisation etc. is simply the need to begin building and have electricity infrastructure in operation, as many countries face looming electricity shortages. This reflects energy law theory, which highlights that developing new energy infrastructure is the key driver of new energy law and policy and states that it is the fourth stage of the evolution of energy law.⁵⁸

Indeed, there are mixed views on the success of the influence of economics in the electricity sector. Supporters of liberalisation believe that it is the most effective way of improving the efficiency and productivity of electricity markets. Critics, however, voice concerns that liberalisation of electricity markets can stifle investment in new generation because wholesale prices are highest and most stable, and therefore most attractive to investors, when the market is suffering supply shortages. This paper has shown how un-liberalised electricity markets, particularly markets with a single-buyer model, have been able to attract private investment and finance through long-term contracts which guarantee minimum returns for properly developed and constructed power plants – albeit such contracts may result in end-customers paying for inefficient and under-utilised assets; though technical operating knowledge has increased across the world, though this issue is in need of future research.

This paper has also demonstrated that from the investor perspective, liberalised markets may experience higher levels of market-risk due to low availability of long-term PPAs, and less favourable PPA terms, dynamic liberalised markets offer mechanisms for mitigating market-risk which lessen the need for long-term PPAs on favourable terms, thereby ensuring the market creates the right incentives for investors but also ensuring efficiency and price-competitiveness for end-users.

Finally, this paper has shown how different market structures exist in the world today from one country to another, and each have slightly different objectives. Consequently, each country presents different manifestations of market risk and requires tailored solutions for successfully attracting private investment and developing new electricity generation capacity. To succeed with their investments, international investors, and their business and legal advisers alike, need to fully understand the electricity market structure, and the risks embodied within such structure, for the countries within which they seek to operate and to structure their projects accordingly.

⁵⁸ Such drivers of energy law are stated as: safety; security; economics; infrastructure; and justice. See: (1) Heffron, R. J. and Talus. K. 2016. The Evolution of Energy Law and Energy Jurisprudence: Insights for Energy Analysts and Researchers. *Energy Research and Social Science*, 19, 1-10.