INTERNATIONAL PROJECT FINANCE

ABOLITION OF LONG-TERM CONTRACTS: WHAT ARE THE IMPLICATIONSAND OPTIONS FOR BANKABILITY IN ENERGY PROJECTS FINANCING?

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Abstract: Liberalisation of energy markets has made a re-examination of the role of long-term take or pay contracts in the financing structures of energy projects inevitable. Abolition of such contracts had been contemplated post-liberalisation in notable energy markets. Although long-term take or pay contracts may yet be viable mechanisms in energy project financing, the prospect of their abolition is a potential but extreme incident in the context of this paper. This therefore provokes an inquiry into the implications of abolition and to determine whether real, flexible and market-based mechanisms exist for assuring predictable cash flows to support the economics of energy project financing in the absence of long-term contracts. In addressing this issue, this paper adopts an analytic approach. It reviews the rationale and functions of long-term contracts, their relevance in the economics of energy projects – pipeline, oil, gas/LNG, and power with specific emphasis on the peculiarities of each project's financing structure/arrangements. The paper reviews the case for abolition and considers the implications for bankability of such abolition for energy financing purposes. Thereafter, the paper reviews and evaluates the possible options for enhancing revenue earning potential of energy projects in the absence of long-term contractual arrangements.

List of abbreviations

CCGT	Combined Cycle Gas Turbines
CFDs	Contracts for Differences
ESI	Electricity Supply Industry
EU	European Union
GSA	Gas Sales Agreement
ISO	Independent System Operator
LNG	Liquefied Natural Gas
NETA	New Electricity Trading Arrangements
NYMEX	New York Mercantile Exchange
OTC	Over the Counter
PPA	Power Purchase Agreement
SPC	Sales and Purchase Contract
US	United States

1. INTRODUCTION

Project finance[1] proceeds on the fundamental principle that limits the lender 'initially' to project revenues for the purpose of servicing the project debt.[2] It is thus, a vital concern in the project credit analysis not only that the project is viable but also that the revenue flows are certain and predictable. The predictability of revenue flows from the project reduces the lender's concern over potential risk of non-payment of the project debt. This factor strongly influences the lender's judgment in respect of the bankability (i.e. acceptance) of the project structure.[3]

For energy projects ranging from pipeline, oil, gas, LNG to power, long-term contracts with their 'take or pay provisions' have been the principal means for assuring predictable cash flows. The lender's paranoia for predictable cash-flows stems from the need to limit its involvement in the project to only credit risks and to locate support for the project loan and arrangements for its repayment within the market. The relevance of long-term contracts to energy project economics is predicated on three factors. First is the high capital intensity of energy projects. Second is the long duration (usually from 20 to 30 years) thus giving the project sponsor adequate opportunities to recoup investments and achieve repayment of project loan plus interest to the lender. Third is the take or pay element. A take or pay provision commits the offtaker/buyer either to take delivery of the specified minimum quantity of the offtake or to pay for the shortfall.[4] The term 'take or pay' is appropriate in the context of an oil, gas or power project structure whilst the same effect is re-enacted in a pipeline project arrangement through 'put or pay /ship or pay' provisions. The peculiar and differential features of particular energy projects and financing arrangements are more clearly highlighted in the body of the paper.

The increasing liberalization of energy markets and the consequent introduction of market discipline have provoked a re-examination of the role or relevance of long-term contracts in terms of energy projects financing. Indeed, there is a certain view that the emergence of competitive market structures in energy markets erodes any

[1] This is the limited recourse finance as opposed to non-recourse or recourse finance types.
[2] Peter Nevitt and Frank Fabozzi : Project Financing (7th ed), 2000 p. 1.
[3] Graham, Vinter: Project Finance – A Legal Guide, 1994 p. 85
[4] Michael, Brothwood: *The EU Gas Directive and Take or Pay Contracts* [1998] OGLTR 318

incentive for firms to conclude long-term contracts.[5] Besides, the inflexibility of traditional long-term contracts heightens the risk to the buyer in terms of market fluidity and volatility.[6] Thus, whilst long-term contracts assure long-term security of supply to a buyer, such value may become considerably diminished in the light of financial difficulties arising by way of supply-demand fluctuations in the market.

The acute financial difficulties which arose within the US and European energy markets in respect of long-term take or pay contracts, particularly at the wake of the transition to competition, have somewhat forced the issue of abolition for contemplation. In fact, at the beginning of the 1990s, some American regulators were in favour of a complete abrogation of long-term contracts and directing all parties to existing arrangements to re-contract.[7] Abolition of long-term contracts is a potential but extreme incident in the context of this paper. It, however, provokes a review of the issue whether real, flexible and market-based mechanisms exist for assuring predictable cashflows to support the economics of energy project financing.

In addressing this issue, this paper adopts an analytic approach. It reviews the rationale and functions of long-term contracts, their relevance in the economics of energy projects – pipeline, oil, gas/LNG, and power with specific emphasis on the peculiarities of each project's financing structure/arrangements. The paper reviews the case for abolition and considers the implications for bankability of such abolition for energy financing purposes. Thereafter, the paper reviews and evaluates the possible options for enhancing revenue earning potential of energy projects in the absence of long-term contractual arrangements. In this paper, the term 'lender' has been used narrowly and in the context of a commercial bank.

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[5] Samantha Hampshire and Steve Wardlaw: *The EU Gas Liberalisation Directive Facing the Future* in 1998 OGLTR 295.
[6] Anna Cretin and Bertrand Villeneuve: *Long-term Contracts and Take or Pay Clauses in Natural Gas Markets* being paper posted on www.w3.toulouse.inra.fr/leerna/cahiers2003/032117.pdf (last visited 11th April 2004)
[7] *Supra* note 4.

2. LONGTERM CONTRACTS IN ENERGY PROJECTS FINANCING

2.1 PRELIMINARY ISSUES

Energy projects[8] often require long-term funding of between 10-15 years. As Vinter pointed out, "[traditionally] long term loans require long-term contracts."[9] The essence of project finance is the raising of funds to finance the costs of a project, debt service and return on equity from cash flows generated by the project.[10] For project sponsors, the attraction for project financing arrangements is influenced by the high-risk profile and capital intensity[11] of energy projects. Project sponsors are thus motivated by the desire to spread risk and limit recourse.[12] Equally, the lender, wishing to limit its involvement in such projects to credit risks, determines the extent to which the proposed project structure has recognized, allocated and mitigated associated risks to enhance the revenue earning potential of the project.

It is locating the appropriate economic/market support for the project that, in the lender's perspective, determines the bankability of such projects.[13] Ultimately, regardless of any potential benefits from the project (i.e. high margins and fees corresponding to the level of lender's involvement in the project) the lender's primary concern is that the project can generate revenue sufficient to repay the project loan plus interest.[14] Accordingly, the lending decision is a culmination of a process of evaluation of the project structure for eligibility and financial and technical feasibility.[15] It may be useful however, to mention here that most energy projects are leveraged from 60% to 80% or at times 90% debt to equity[16] depending usually on the creditworthiness of sponsors, the risks and the location of the project.[17]

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[8] The energy sector had traditionally dominated the lending markets, accounting for 12% of the total market by value, the biggest market share of any sector. See Petroleum Economist, June 1998.
[9] Vinter *supra* note 3 p. 75.
[10] Marjena, Sokalski: *Critical Issues in Project Finance Documentation in the Context of Syndicated Lending in Central and Eastern Europe* in [1997] 7 OGLTR 256.
[11] It has been estimated that funding requirements for the global oil and gas industry are in excess $300 billion dollars. See David Winfield *infra.*
[12] David Winfield: *Oil and Gas Financing Agreements* in Upstream Oil and Gas Agreements (Martyn David ed), 1996 p. 137 – 141.
[13] Vinter: *supra* note 3 p. 85.
[14] *Supra* note 3 p. 4.
[15] Nevitt: *supra.* note 2 p. 10. See also www.eib.org (last visited 11th April 2004).
[16] A lower debt to equity ration implies lower risk to lenders and implies higher commitment to project sponsors. Sponsors not wishing to lock their funds into a single project will prefer a high debt to equity ratio. See Hossein Razavi *infra.*
[17] Hossein, Razavi: Financing Energy Projects in Emerging Economies, 1996 p. 7.

2.2 LONG-TERM CONTRACTS: RATIONALE AND FUNCTIONS

Long-term contracts facilitate capital investment in major projects where returns accrue over long periods.[18] In energy projects, long-term take or pay contracts provide the mechanism for assuring to the lender predictable cash flow. Long-term contracts are contracts whose duration usually ranges from 20 to 30 years. In this context, they differ and are easily distinguishable from short or medium contracts.[19] The thinking is that such long duration enhances sponsors' potential to recoup their investments in the project and to pay the project debts. The take or pay element in such contracts guarantees that in any event the project earns revenue.

The take or pay provision requires the offtaker/buyer 'either to take delivery of not less than a specified minimum quantity of the product, say, gas over a specified period (typically a year) or if the buyer does not in any event take that quantity, to pay for the shortfall of that quantity from the agreed minimum quantity' subject, of course, to deductions for deliveries not taken due to *force majeure* and non-delivery by the seller/producer.[20] The term 'take or pay' is appropriate in the context of an oil, gas or power project structure whilst the same effect is re-enacted in a pipeline project arrangement through 'put or pay /ship or pay' provisions.

Thus, a take or pay contract will usually perform the following functions:

- protect revenue stream for seller;
- assure the bank to support third party or project financing;
- support project economics and enhance decision making;
- move risk;
- useful as trade off against other key components of price;
- secure commercial advantage;[21] and
- provide less negative impact on the credit of the sponsor than a guarantee.[22]

In other words, take or pay contracts are risk-sharing instruments between producers and buyers due to long lead times in investment planning and capital-intensive

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[18] Take or Pay Contracts being part of the ACIL Report posted on www.med.govt.nz/ers/gas/reviewsacilreport/acilreport-09.htm/#p1956.318025 (last visited on 11 April 2004).
[19] Bleddyn, Phillips: *Examining the Future of Long-term Take or Pay Contracts* in [1997] 3 OGLTR p. 73.
[20] Michael, Brothwood: *The EU Gas Directive and Take or Pay Contracts* [1998] OGLTR p. 318.
[21] David, Martyn: Natural Gas Agreements, 2002 p. 183.
[22] Nevitt: *supra*. note 2 p. 327.

operations.[23] Also, they serve as mechanisms for effecting appropriate incentives for contractual performance. [24]

The relevance of long-term contracts to the economics of specific energy projects is now closely examined.

2.3 ROLE IN SPECIFIC PROJECTS

2.3.1 Pipeline Projects

In most energy markets, pipelines systems are classified as natural monopolies and this could be a crucial factor for project financing purposes since this naturally indicates regulation and the potential for insufficiency of income stream if the price cap (RPI-X) is too low.[25] The economics of pipeline projects consist in high upfront costs, low and relatively fixed operating costs and long pay back period.[26] As Bruce Payne notes, "a pipeline payback period is rarely less than 10 years".[27] In evaluating a pipeline project structure for financing purposes two issues become crucial: allocation of capacity and tariff.[28]

Pipeline project revenue consists in tariff charges normally based on a fee per barrel of oil or specified volume of gas transported over a set distance. Accordingly, the tariff has to be structured so that for expected monthly volume shipment, revenue returns will be sufficient to cover the operating costs, debt service, taxes, return on capital and a profit margin necessary to generate return on investment.[29] Pipeline project economics is supported through a long-term throughput contract. The throughput contract commit sponsors to throughput into the pipeline a certain minimum quantities of oil, refined products or specified volume of gas at fixed rates. Given that the throughput contract contains a put or pay/ ship or pay clause, each shipper is unconditionally obligated to ship a certain minimum amount during a time

[23] Cretin and Villeneuve: *supra* note 6 p. 3
[24] *Ibid.*
[25] Paul, Horsnell: *Liberalisation of the European Natural Gas Industry and Its* Implications in The Future of Natural Gas in the World Energy Market, 2001 p. 28.
[26] A rule of the thumb for pipeline capital expenditure cost is [about] $1m per mile for a large diameter pipeline across relatively flat, non-environmentally sensitive terrain and this does not include the cost of an offshore loading terminal. See Bruce Payne *infra.*
[27] Bruce, Payne: *Project Financing Oil Pipelines in the Caspian Region* in [1998] OGLTR p. 381 at 384.
[28] Jeremy, Deeley: *Gas Transportation Agreement* in Upstream Oil and Gas Agreements (Martyn David ed), 1996 p. 117 at 123.
[29] *Ibid.*

period. Hence, if any sponsor fails to ship during a time period, the shipper must pay for the minimum shipment.[30]

2.3.2 Oil Projects

Oil projects generally require substantial funding requirements. However, borrowing by a sponsor to finance its cash call obligations under the Joint Operating Agreement (corporate borrowing) must be distinguished from a classic project financing arrangement.[31] An oil project would consist of, for example, field development, construction of a floating platform, pipeline or other transportation facilities.[32] Hence, a classic project financing scenario for oil project means "debt that is lent for the development of a single project…on the basis that the lenders will be entitled to look solely to the cashflows (or disposal proceeds) from the relevant project or asset as their means of repayment".[33]

Prior to the development of spot, futures and forward markets in oil, oil used to be sold on long term-contracts from producers to refiners.[34] Term contracts in oil projects are commitments to sell a specified quantity of oil over a certain period. Accordingly, if the project involves the development of an oil field, long-term offtake contracts with 'take or pay provisions' provide the basis for securing predictable revenue stream for the amortisation of the loan in the time and manner envisaged by the lender.

2.3.3 Gas Projects

Investments in gas development projects are rarely undertaken in the absence of potential demand since such development requires substantial capital outlay and there is as yet no international market for gas.[35] The development of an international market in gas has been slowed down due to the high upfront costs of building the necessary transport infrastructure. As it were, "natural gas must be transported in its gaseous form in pipeline or in a liquid form by tanker. It may cost as much as four or

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[30] See Nevitt *supra* note 2 p.330 for further analysis on the structure and effect of the throughput contract.
[31] Vinter's discussions of financing in the North Sea relate to cash call borrowing rather than the typical project financing arrangement. See Vinter: *supra* note 3 p. 251-253.
[32] Winfield: *supra.* note 12 p. 139-140.
[33] *Ibid.*
[34] Smith *et al*: International Petroleum Transactions (2nd ed), 2000 p. 763.
[35] Andrew, Flower: *LNG Project Feasibility* in Liquefied Natural Gas - Developing and Financing International Energy Projects (Gerald Greenwald, ed), 1998 p. 73

five times as much to ship gas over land by pipeline, as it would cost to ship oil. Transporting natural gas by tanker in liquid form may cost thirty times as much as shipping oil."[36]

Gas field development requires significantly high upfront capital expenditure aggravated by the peculiar constraints of gas as a commodity. Thus, gas was sold initially on long term-contracts on a depletion basis then much later on a supply basis. This provided the incentive for financing because of the inclusion of take or pay terms in the Gas Sales Agreement (GSA). Under a depletion contract, gas is "supplied from a specific field which is generally, but not always dedicated exclusively to the buyer under the contract".[37] In a supply contract, however, there is no specific field identified as the source of the gas; the seller is free to supply gas from any field available to it.[38] The material issue here is that the GSA contains take or pay provisions, which ensure a guaranteed income to the seller/producer to justify the investment to develop the gas field. Whilst the duration of a supply contract may be fixed in excess of say, 15 years, it is usually until the field becomes uneconomic under depletion contracts.[39] Hence, a revenue stream for the purpose of debt service, payment of operating expenses and possibly, for return on investment is secured.

2.3.4 LNG Projects

The LNG project chain comprises four elements namely: gas production, liquefaction plant, shipping and the receiving terminal including regasification plant. The LNG project chain is such that the financing plan for the gas production and liquefaction is almost always closely linked with the financing of the receiving terminal and regasification plant.[40] The project economics for an LNG value chain unfold as follows:

- gas production costs;
- liquefaction costs (construction and operation cost of the liquefaction plant or other processing facilities);[41]

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[36] *Supra,* note 31 p 913.
[37] Niall, Trimble: *An Introduction to Gas Sales Agreement* in [1992] 11/12 OGLTR p. 331. See also Danielle Beggs: *Gas Sales and Supply Contracts* in Natural Gas Agreements (Martyn David, ed), 2002, 149.
[38] *Ibid,* note 37.
[39] *Ibid,* note 37 p. 335.
[40] Flower: *supra*. note 35 p. 83.
[41] *Ibid.*

- pre-liquefaction costs (cost of obtaining, and extracting impurities from the feed gas);[42] and
- shipping costs (the costs of building new vessels or hiring charter parties) [43]; and
- regasification costs (construction and operation cost of the receiving terminal/regasification plant or other processing facilities).

It is crucial to the LNG project economic analysis to ensure that the "cost of the feedgas delivered to the LNG plant (after taking into account revenues from condensates, LPGs and gas sold for local use, if any) [is] low enough to allow LNG to be delivered to the buyer at a price which, after taking into account the buyer's storage and regasification, is competitive with other fuels in the market".[44]

The contractual mechanism that has been used to justify the considerable capital expenditure required for the LNG project structure is the long-term Sale and Purchase Contract (SPC). The duration of such SPCs usually range from 20 to 25 years.[45] The SPC usually includes take or pay terms which oblige the buyers to take delivery of all of the sales contract quantity or pay the contract price for any quantity not taken. For LNG sellers, such is an essential requirement for loan repayment and investment returns.[46] The magnitude of upfront capital investment involved in the LNG value chain makes this imperative.

2.3.5 Power Projects

Until the emergence of new technology options (CCGTs for example), which facilitate smaller plants with greater output and relatively cheaper cost and shorter lead times,[47] the economics of power projects was dominated by scale and long lead times within the context of a vertically integrated electricity supply industry. Power

[42] The liquefaction process depends on a clean feed gas to work effectively. Impurities in the feedgas will thus increase the project costs. See Flower: *supra*. note 35 p. 82-83

[43] Cost arising under charter parties of LNG tankers include charter payments on ship or pay basis. Shipping costs account for between 25 to 40% of the total capital cost of an LNG chain. See Flower: *supra* note 34 p. 101-102

[44] Flower: *supra* note 35 p. 83

[45] Robert, Jones: *LNG Markets – Historical Development and Future Trends* in Liquefied Natural Gas - Developing and Financing International Energy Projects (Gerald Greenwald, ed), 1998 p. 52.

[46] An example here is the TEPCO contract of October 1990 to increase annual purchase of LNG to 4.7 mt for a 25-year period commencing 1 April 1994 from the Abu Dhabi two-train LNG Plant. See Gerald, Greenwald: *LNG Project Finance – Sharing Risks with Project Lenders* in Liquefied Natural Gas - Developing and Financing International Energy Projects (Gerald Greenwald, ed), 1998 p. 247.

[47] Sally, Hunt: Making Competition Work in Electricity, 2002, p. 25-27.

project economics thus depend largely on construction cost, the fuel source and related-cost as well as the market structure. Coal-fired, hydro-powered and nuclear-powered plant projects are extremely capital-intensive projects, prone to environmental concerns and require long lead times of sometimes up to ten years to build and another thirty years to recover the cost.[48] It is an imperative of the power project structure that a predictable revenue stream is guaranteed firstly, for the purpose of debt servicing and secondly, payment of operating and maintenance costs for the plant.[49] The contractual mechanism that has been used to achieve this in the power project structure is the Power Purchase Agreements.[50]

Payment terms under the PPA are usually structured to impose take or pay obligations[51] on the offtaker (usually a monopoly under the BOT scheme or a wholesale/bulk purchaser). Hence, the PPA provides for the availability payments/charge as well as a price formula (£x/kWh), which covers capacity and energy charges for actual dispatch.[52] The availability payment is the take or pay element in the PPA and will be payable whether or not the plant is actually dispatched.[53] As Hunt noted, "availability payments provide extra revenue to the generator to cover the capital and other fixed costs which are not covered by the energy price per kWh".[54] The duration of the PPA is set at a period long enough to enable the power sponsors to recoup their investments subject, of course, to buy out or step in rights in the concession contract or under the PPA.[55] It is needful to point out that the PPA can only so much as mitigate the market risk in the project structure by ensuring guaranteed electricity offtake whilst the risk of insufficiency of income stream remains because of regulation/government intervention in the pricing policy of the offtaker especially where it is a monopoly.

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[48] Walt Patterson: Transforming Electricity, 1999, p. 46-48.
[49] Vinter *supra* note 3 p. 75-76
[50] See Sally Hunt and Graham Shuttleworth: Competition and Choice in Electricity, 1996, p. 109-117.
[51] Take or pay contracts were required in the later development of gas fired power stations as banks financing such projects required guaranteed gas supply and long-term pricing and seller would only be prepared to commit supplying firm gas otherwise the buyer could choose to purchase in the market if the market sprice was lower than the contract price. See Henry Davey: *Take or Pay and Send or Pay – A Legal Review and Long-term Prognosis* in [1997] 11 OGLTR 419.
[52] *Ibid*. See also IFC: *supra*. note 46 p. 46.
[53] Vinter *supra* note 2 p. 75
[54] Hunt and Shuttleworth *supra* note 50 p. 111.
[55] *Ibid*, p. 75-76.

Having reviewed the role of long-term contracts in energy project economics, then what is the case for abolition?

3. LONG-TERM CONTRACTS: THE CASE FOR ABOLITION

The following reflects some of the issues regarding buyers' discontent and the case for the abolition of long-term contracts in energy markets.

3.1 UNRECOVERABLE COSTS - PREPAID OFFTAKE

There is a potential for the buyer to incur considerable sunk costs where prepaid offtake is not recovered by the buyer before the expiration of the take or pay contracts. Usually, long-term contracts in addition to the take or pay clause, contain make-up or carry-forward provisions which assist the buyer to average out its take or pay obligations over the life of the contract.[56] These provisions, however, could also reinforce the potential for sunk costs (which in most instances will be considerable) for the buyer. This is because the buyer must recover the offtake amounts paid for but not taken during the life of the contract otherwise they are forfeited.[57]

3.2 IMPACT OF LIBERALISATION

The profile of returns under long-term contracts is often based on long-term demand and price projections. For instance, the amount of gas required by a monopoly offtaker will be fairly stable to predict or at least, may be simple to forecast. However, with liberalisation, the offtaker's market share changes much more quickly and unpredictably that to take a long-term view of demand becomes difficult. In this circumstance, the take or pay contracts may change from being long-term obligations or in certain cases, hedging instruments (e.g. protection from spot market prices) into risk creating contracts if the wrong commercial decisions are taken.[58] An acerbic view is that of Horsnell to the effect that in the liberalized market, the take or pay

[56] The make-up applies where the buyer takes less than the take or pay quantity and pays for the offtake amount not taken which then goes into a make-up bank. In the case of the carry forward clause, the buyer takes more than the take or pay quantity and receives a credit. The buyer can then reduce his take or pay liability by the amount of the carry forward balance. See Trimble: *supra*. note 36 p. 334. See also Cretin and Villeneuve: *supra*. note 5 p. 1.
[57] Note 18 *supra*.
[58] Hampshire and Wardlaw: *supra*. note 5 p. 298.

contract 'is essentially dead'.[59] Indeed, "a volatile liberalized market is not an arena conducive to long term arrangements and financial guarantees are almost impossible to achieve at reasonable cost for such a contract."[60] The impact of liberalisation on long-term take or pay contracts is better appreciated in the context of the liberalisation of the gas and electricity markets in Europe and the US.

3.2.1 Gas

The UK gas industry experience provides a useful starting point.[61] The then British Gas Corporation was the sole buyer of gas in the UK and was in charge of transmission and distribution with its network of pipelines. When it was privatized in the 1990s, British Gas Plc inherited a portfolio of long-term purchase contracts with gas producers. The combined effect of the EU Directive lifting the restriction against the use of gas for power generation opened up new markets in gas coupled with the release of short term gas supplies by British Gas Plc under the gas release programme drove spot gas prices down sharply below contract price levels such that the contract prices became unsustainable.[62]

3.2.2 Pipeline

In the US prior to deregulation, interstate pipelines served as gas merchants and purchased gas from well owners and then transported and sold the product to local distribution companies. Accordingly, they entered into long term take or pay contracts, which as a result of the gas boom of the early 1980s and the deregulation of the sector in the US, forced pipelines to default on their take or pay obligations because 'the locked in contract prices were significantly above the market price and end users refused to pay the higher prices thus resulting in higher take or pay liabilities.'[63] After deregulation pipelines are no longer permitted to deal in 'bundled' gas or services [64] It was the 1998 Gas Directive that established the regime for open access (Third Party Access) and transformed the pipelines into common carriers in

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[59] Horsnell *supra* note 25 p. 42.
[60] *Ibid.*
[61] Mike McSherry: *The Impact of Gas Release on Gas Market* in [1991] 9/10 OGLTR 243 at 244.
[62] *Ibid,* p. 32.
[63] Smith: *supra.* note 34 p. 917. See also Peggy, Heeg: *Gas Transportation in the United States – What's to be Learned?* in 1997 10 OGLTR 381 at 384.
[64] For details on the US deregulation experience and the effect on pipelines, see Smith: *supra.* note 35 p. 916-918; John Lowe: *The Take or Pay Wars – Is Peace at Hand?* in 1989/90 1 OGLTR 3; Cretin and Villeneuve: *supra.* note 5 p. 8.

Europe. These changes create a market where end users negotiate directly with gas producers and then arrange transportation with regulated pipelines in Europe and US respectively.[65]

3.2.3 Power

The UK is a case in point. The liberalization of the UK ESI resulted in the unbundling of the CEGB and the grant of new generation licences to allow new entrants to compete with NationalPower Plc and PowerGen.[66] The liberalization also established a market trading system in which electricity is freely traded as a commodity like any other fuel source. A new system of setting prices (the power pool)[67] was created at which generators sold power to the public electricity supplier. The pool prices were highly volatile but were hedged through contracts for differences,[68] which also served as the basis for financing power projects[69] until retail competition was introduced thereafter. As it were, the structure of the market posed a strong disincentive for entering into long-term contracts for fuel supply since a generator with a high price gas supply contract will be setting itself up for financial risk where the pool price becomes uncompetitive.[70]

3.2.4 Oil

The case of oil is slightly different. It was the price disruptions of the mid-1970s that diminished the value of long-term contracts in oil project financing arrangements. Most parties became reluctant "to bind themselves for protracted periods or to agree to a fixed price".[71] The preference is now for more short-term contracts with flexible pricing provisions to protect against the fluctuations in the daily oil price.

3.3 COMPETITION ISSUES

Long-term contracts have also been found to trigger some competition concerns. Some of these are examined in the context of the EU.

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[65] Cretin and Villeneuve *supra* note 6 p. 14.
[66] Vinter *supra* note 3 p. 261-262. See also Bailey and Tudway *supra* note 52[b] cap.6 p. 5 para 6.090.
[67] Note that a new trading arrangement called NETA (New Electricity Trading Agreement) has been adopted for electricity trading in the UK with effect from March, 2001.
[68] Josh, Danziger: *The Forward Market in Electricity* in OTC Markets in Derivative Instruments (Nick Cavalla, ed), 1993, p. 101-122 at 111.
[69] Vinter *supra* note 3 p. 82, 263. See also Danziger *supra* note 58 p. 101.
[70] S., Bailey and R., Tudway: Electricity Law and Practice, 1992 cap 3 p. 2 para 3.04.
[71] Smith *et al supra* note 34 p. 763.

3.3.1 Barriers to Entry

The Commission has recognized that long-term contracts have the potential to frustrate the development of competition either through explicit inclusion of restrictive conditions or by creating dominant positions, which may deter the entry of small players into the market.[72] A notable restrictive condition is exclusivity of sale/supply.[73] The Commission's position becomes understandable if it is realized that the oil majors dominate upstream competition of the gas market for instance. This is not a problem in the US where gas is supplied by a large number of small producers.[74]

3.3.2 Duration

The Commission has limited duration for long-term contracts within the EU to 15 years.[75] The main rationale is the need to free up the market and to avoid locking up capacity in a long-term contract than is necessary. In the *Scottish Nuclear case* where the agreement was for 30 years and the Commission had limited it to 15 years, the Commission stated that the 15-year period was sufficient to allow Scottish Nuclear to attain full profitability and become competitive.[76]

3.3.3 Price

It is equally the view that long-term contracts restrict effective price competition since the ability of a new supplier to undercut the contract price may be constrained.[77] Besides, price inflexibility of long-term contracts is equally a factor. The Commission has observed that several forces put strong pressure on suppliers to renegotiate existing contracts to adapt to a changing regime and to organise much more flexible pricing provisions.

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[72] See the OFFER Annual Report 1989, p. 5. where the entry deterrence implications of long-term contracts was recognized. See also Bailey and Tudway *supra* note 52[b] cap 6 p. 10 para 8

[73] See *Liberalisation of Energy Markets – The EU Perspectives* posted on www.freshfields.com/practice/publication/pdf/1937.pdf (last visited 17th April 2004).

[74] Cretin and Villeneuve: *supra* note 5 p. 14.

[75] Danielle Beggs, *supra* note 37[b] p. 150. See also the EU Gas Directive 1998.

[76] Faull and Nikpay *supra* note p. 710-712. See also the decisions of the Commission in the Pego (1993 OJ C265/3), Turbogas (1996 OJ C118/7) and ISAB Energy (1996 OJ C138/3) line of cases; See also the EU Gas Directive, 1998.

[77] *Ibid.*

3.3.4 Capacity Reservation

Long-term capacity reservation agreements have equally been regarded as anti-competitive as they are capable of foreclosing the market for capacity and deter entry.[78]

Some American regulators, which proposed the abolition of long-term contract and directing parties to existing contracts to re-contract post-deregulation, most probably had the above issues in mind given the challenges of the US energy markets deregulation.[79]

If the above case is accepted, then the inevitable is to consider the possible implications the abolition of long-term contractual arrangements hold for the capacity of sponsors to raise project finance for energy projects and whether there are adequate, real and flexible market-based instruments that will support predictable cash flow for lending purposes.

4. ISSUES FOR BANKABILITY

4.1 IMPLICATIONS FOR BANKABILITY

Clearly, abolition strikes at the root of project financing conceptually. The primary premise for project finance is that the project should be capable of generating returns or revenue sufficient to service the project debt.[80] It is the project's capacity for predictable revenue stream that sustains the project economics and enhances lender's decision-making as well as provide some guarantee or assurance to the lender. A project is not considered bankable where risks that are crucial to the earning potential of the project have not been identified, allocated and mitigated within the project structure to the lender's satisfaction.[81] The ability to locate credit support for the project loan in the market through a demonstrably creditworthy offtaker enhances the lending decision. From the lender's perspective, this reduces the market risk in the

[78] *Ibid.*
[79] Cretin and Villeneuve *supra* note 5 p. 11.
[80] T. Donaldson and J. Morgan: *The Traditional Approach in Project Lending* in Project Lending (T. Donaldson, ed), 1992, p. 3.
[81] *Ibid*, p. 4-5.

project structure. A review of the current scenario for energy project financing affords a better appreciation of the issue

Today, the number of banks acting as lead arrangers for major energy project lending has decreased dramatically in the last five years.[82] Secondly, there is a decline in the number of banks with capacity to participate in energy project financing at syndication level.[83] Thirdly, the banks with available debt capacity have become more risk averse.[84] Fourthly, prospective buyers in the market today are typically less credit worthy than the traditional financially strong monopoly utilities.[85] Fifthly, price risk has become one of the biggest issues in energy project financing due to the development of spot markets in most energy industries at the wake of liberalisation.[86]

Accordingly, an instant implication of abolition is the heightening of the market risk arising from price unpredictability and difficulty in volume allocation and the subjugation of the offtake to the vagaries of market conditions. The potential impact of price volatility or energy price risk on the economics of energy projects can therefore not be over-emphasised.

Two reactions are possible from the lender, however. Firstly, the lender may simply not lend. Secondly, the lender may decide to lend but from a conservative position and to account for the higher risks the lender is invited to assume where the lender decides to lend, the loan may be priced very expensively with equally significantly high margins on top. However, even where the lender prices the loan very high, an 'isolated and assignable'[87] cashflow stream must still be identified or possible within the project structure. In addressing this concern, the lender's emphasis may shift from a consideration of the project's capacity to earn revenue sufficient to service the debt to the credit of the sponsors. The lender may thus request a higher equity commitment from the sponsors. Thus, the equity to debt ratio swings higher for "the higher the equity in the project, the lower the risk borne by lenders"[88]. In this respect,

[82] Terry Newendrop *et al*: *Flexible Friends* in Project Finance Dec 2002/Jan 2003 p. 24
[83] *Ibid.*
[84] *Ibid.*
[85] Susan Farmer: *LNG in the Twenty-first Century* in 1999 17 OGLTR 102-104 at p. 102.
[86] Newendorp *supra* note 5 p. 24
[87] Nevitt: *supra.* note 2
[88] Razavi *supra* note 17 p. 7.

either or a combination of the following agreements may become crucial in the project documentation:

- *Sponsors' Guarantee* – The lender may request the sponsors to guarantee a minimum price for the cash flow projection to be viable.
- *Cash Deficiency Agreement* - The lender may also impose onerous cash deficiency obligations on the sponsors through the CDA. This is an agreement designed to cover any cash shortfalls that would impair the project's ability to meet its debt service requirement. In this respect, "the obligor makes a cash payment sufficient to cover the cash deficiency."[89]
- *Capital Subscription* – The lender may also oblige the sponsors to purchase for cash securities issued by the project company to the extent required to enable the project cover any cash shortfall.[90]
- *Clawback Agreement* - The lender may equally require sponsors to provide an undertaking to contribute cash to the project to the extent that they received any cash dividends from the project company or any project related tax benefits on account of their investments in the project.[91]

All these arrangements imply a strong emphasis on sponsors' credit in the evaluation of the project structure. Eventually, the objectives of the sponsors to limit recourse and spread risk become defeated.

4.2 OPTIONS FOR BANKABILITY

The relevant question therefore is whether there are real, flexible and market based mechanisms by which sponsors can assure a predictable revenue stream within the project structure to enhance the bankability of energy projects. Although some of the options considered below and analysed in the context of specific projects (include forward contracts, futures and swaps, which have been used primarily as hedging instruments), the issue is whether one or a combination of some of these instruments offer opportunities for securing a predictable income stream for energy financing purposes.

4.2.1 Forward contracts

[89] John, Finnerty: Project Financing – Asset-based Financial Engineering, 1996, p. 64
[90] *Ibid.*
[91] *Ibid.*

A forward contract is "an agreement to buy or sell an asset at a certain future time for a certain price. It is not normally traded on an exchange. One of the parties assumes a long position and agrees to buy the underlying asset on a certain specified future date foe a certain specified price. The other party assumes a short position and agrees to sell the asset on the same date for the same price."[92]

The specified price in a forward contract is the delivery price. Actual delivery is key to forward contractual arrangements. Hence, the obligation is on the contract seller to deliver to the contract buyer the agreed or specified quantity of the offtake on the date and at the stated price agreed at the time of entering the contract.[93] The advantage of forward contractual arrangements from project financing perspectives is that it allows the seller to transfer both the price risk and quantity/volume risk to the buyer.

- *Oil, Gas and Electricity Forward Contracts*

Oil has a developed product market. Forward contracts in oil involve a specific type of oil that is loaded into the nominated tanker at a single loading terminal during a specified month in the future.[94] Forward contracts dealing with each specific type of oil constitute 'the forward market' for that oil. Forward sale in oil assures a producer that production at current volumes can be disposed of without complete dependence on the volatile prices of the spot market.[95] This is crucial for project lending. It may mean that all that sponsors need to do is to demonstrate a portfolio of forward contracts to assure a predictable revenue stream. For an oil project, this should not be difficult. An example of a forward market in oil is the Brent Market in North Sea Crude.[96]

Gas unlike oil does not have an international market. As such, gas prices are usually based on competition with alternative fuels particularly in Europe. Liberalisation and development of spot market in gas, however, have aided the emergence of natural gas prices not indexed to competing fuels and also the opportunity to sell gas forward. In the US, forward sales/purchase have been entered into between gas producers and gas suppliers to enable gas suppliers obtain dedicated reserves at competitive prices.[97]

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[92] John, Hull: Options, Futures and Other Derivative Securities, 1989, p. 4. See also, Hunt and Shuttleworth *supra* note 50 p. 100.
[93] Finnerty *supra* note 88 p. 44.
[94] Smith *et al supra* note p. 769.
[95] *Ibid.*
[96] *Ibid.*
[97] Winfield *supra* note 10 p. 162.

The commoditisation of electricity has enhanced the prospects of its sale forward. For instance, in the Eltermin market of the Nordic Power Market, market participants trade for delivery up to four years.[98] Forward contracts may limit exposure on price risk by locking in the market prices. As Hunt noted[99], forward contract protects both the generator and the buyer against variation in market prices during the hours in which the contract is valid. This view assumes a market structure that is organized as a pool where prices are set according to a merit order at half-hourly intervals.[100] In such markets, forward contracts do not provide any protection against quantity or volume risks "It is difficult to match forward contracts to an unpredictable pattern of output."[101] This is crucial for project financing which requires some form of predictable benchmarks to project potential revenue stream. In order to manage incidents of volume risks, it is usual for forward contracts to be coupled with an option.

Although forward contracts are often flexible to meet the commercial needs of the parties to them, the need for a market price for a delivery at a specific place far into the future may be daunting. For instance, the system marginal price is used as a reference price for forward contracts. After the collapse of the California power market in the summer of 2000, the California Independent System Operator (ISO) had to discover the price for electricity delivered in the future through lengthy, expensive negotiation, because there was no market price for future electricity deliveries. There is equally the risk of default where the forward price is much more different from the market price. Also, a downside of this arrangement is the possibility of changes in the circumstances of one of the parties. The only way for a party to back out of a forward contract is renegotiation and even then such a party may face penalties.[102]

4.2.2 Futures

This is a contract to purchase or sell a commodity for delivery in the future at a price that is determined at the initiation of the contracts and which obligates each party to

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[98] T., Kristiansen: *Pricing of Contracts for Differences in the Nordic Market* being paper posted on www.elkraft.ntnu.no/tarjei/energy_policy.pdf (last visited 17th April 2004).
[99] Hunt and Shuttleworth *supra* note 50 p. 124
[100] In markets, which operate on the basis of bilateral contracts, spot prices are functions of transactions between generators/wholesalers and electricity suppliers and industrial users.
[101] Hunt and Shuttleworth *supra* note 50 p. 124.
[102] EIA: *Derivatives and Risk Management in the Petroleum, Natural gas and Electricity Industries* posted on www.eia.doe.gov/oiaf/servicecerpt/derivative/chapter2.html (last visited on 17th April 2004).

fulfill the contract at a specified price. It is used to assume or shift risk and may be satisfied by delivery and offset.[103] Futures have been standardized and only offered by, and traded on a futures market/exchange. Accordingly, buyers and sellers of commodity deal with the exchange and not with each other. The exchange specifies the amount of the [product] to be delivered for one contract, how the price is to be quoted and the limits of the future price in any day'.[104] The contract is usually referred to by its delivery month whilst the exchange specifies the precise period during the month when the delivery must be made.[105] In this context, futures although a type of forward contract, can be distinguished from the typical forward contracts.

Whilst delivery is not an essential feature of futures because of the potential to offset obligations before maturity, delivery is crucial from the perspective of a buyer given the need for assured supply. Settlement between buyers and sellers of futures is made on a daily basis with the contracts settled by reference to the spot price of the product. As a rule, parties are required to make margin deposit to protect against default. The future price when delivery is made should be the same as the spot price at that date. Future contracts in oil, gas and electricity have been sold on the NYMEX and some other exchanges.[106]

For project financing purposes, the futures market is highly volatile and might not offer significant opportunities to manage price risk. Again, futures are available only at few delivery locations and are not available for deliveries for decades or more into the future.[107] It has also been suggested that application of futures contracts to for instance, electricity may raise legal and regulatory issues.[108] Such may have significant impact on the project credit analysis by the lender.

4.2.3 *Options*

Option contracts give the buyer the right to buy (a call option) or sell (a put option) at a specified price (the "strike price") over a specified period of time.[109] American

[103] CFTC Glossary as posted on www.cftc.gov/opa/glossary/opaglossary_f.htm#/forwardcontracts (last visited 17th April, 2004).
[104] Hull *supra* note 91 p. 5
[105] *Ibid.*
[106] These include particularly for oil, International Petroleum Exchange, the London Exchange, Singapore International Monetary Exchange.
[107] EIA *supra* note 89.
[108] Lloyd, Kavanagh and Abby Lawrenson: *Electricity Futures Contracts – Don't Get A Shock* in [1997] 4 OGLTR 128.
[109] Hull *supra* note 91 p. 9.

options allow the buyer to exercise his right either to buy or sell at any time until the option expires. European options can be exercised only at maturity. Whether the option is sold on an exchange or on the OTC market, the buyer pays for it up front. It will appear that for project financing purposes, sponsors would need to acquire/obtain put options to sustain credible projected cash flows. The put option would be issued by the offtaker(s) to the sponsors allowing them to sell to the buyers at a fixed price and for a given period of time. The option requires sponsors to pay a premium charge to the buyers. However, this may be set-off through a back-to-back arrangement whereby sponsors equally issue call options at equivalent premium charge to the buyers. Options are useful to lock in prices and volume and as such relevant to project financing.

Under options, only a right to buy or sell is granted. There is no obligation to buy or sell. Lenders would require more than a right to buy or sell but a commitment to buy and pay for the offtake as a basis for deeming the project bankable.

4.2.4 *Swaps*

In swaps, no physical commodity is actually transferred between the buyer and seller. The contracts are entered into between the two counterparties, or principals, outside any centralized trading facility or exchange and are therefore characterized as OTC derivatives. Because swaps do not involve the actual transfer of any assets or principal amounts, a base must be established in order to determine the amounts that will periodically be swapped. This principal base is known as the 'notional amount' of the contract.[110] Its most common application is in the form of Contracts for Differences in electricity markets and it is for settlement of payment difference.[111] Whilst swaps can provide some form of hedge against price risks, it is doubtful if project finance for energy projects can be raised from a portfolio of swaps.

4.2.4 Present Trends

Generally, the present trend in liberalized energy markets is towards shorter term and flexible contracts incorporating all manner of price adjustment mechanisms. This trend is more closely reviewed in terms of specific project. The question however is,

[110] Hull *supra* note 91 p. 17, 283-290
[111] Hunt and Shuttleworth *supra* note 57 p. 104.

whether this marks the end of long-term take or pay contracts in energy project financing.

A) Gas

- *Existing Contracts*

In both the US and Europe, liberalization exerted strong pressure on existing long term take or pay contracts due to the force of the emergent spot market[112] in gas and the attendant price volatility. This resulted in existing contracts being renegotiated and new and more flexible pricing provisions were introduced. Examples of such provisions include price review clauses, price escalation clauses, renegotiation clauses and other price re-openers.[113] There is also the take or pay holiday clause, which is intended to give buyers of gas some reprieve.[114] A similar device is the derogation procedures introduced by the 1998 Gas Directive in the EU.[115]

- *New Contracts*

For new contracts the approach is to combine shorter-term contracts (at least more than five years) with flexible pricing provisions, which allow the parties to adapt to changes within the product market.[116] Also, with respect to contract volume, a conservative minimum amount of gas is contracted whilst the buyer is allowed to buy from, and the seller can sell the uncontracted volume to the spot market.[117] This implies that the contracted amount can provide some support to raise project finance as it may guarantee a significant percentage of the offtake and mitigate considerably the volume risk. Again, the possibility of long-term take or pay contracts abides even if not for more than 15 years in the EU internal energy market. This is crucial for the EU as this may enhance the prospects of increase in internal gas field development projects to tap EU's recoverable potential of about 13,500 billion cubic metres of

[112] The Henry Hub spot market provides the gas price reference point in the US. The EU is developing two additional hubs to the Zeebrugge in Belgium, which will relieve gas prices from being indexed to oil prices in the EU.
[113] Davey *supra* note 61 p. 421. See also Brothwood *supra*; Phillips *supra* note 19 p. 73-78
[114] Phillips *supra* note 19 p. 77.
[115] Brothwood *supra* note 4. See also Adam Langridge: *European Regime for Take or Pay Contracts* in [1998] OGLTR 372.
[116] Phillips *supra* note 20 p. 74. See also Hampshire and Wardlaw *supra* note 5 p. 296.
[117] Hampshire and Wradlaw *supra* note 5 p. 297.

natural gas. It also enhances the prospects of security of supply from external gas supply sources to the EU.[118]

B) Pipeline

Long-term through put contracts have been crucial to pipeline investments both for greenfield and expansion projects. Even with liberalization, pipelines remain natural monopolies within the gas industry.[119] Both transmission and transport services remain bundled. Transmission tariff and transport charges are subject to regulation. With respect to capacity reservation, the approach of pipelines since liberalization is to combine a portfolio of reserved capacity with significant 'on demand' capacity. In the EU, long-term reservation transmission capacity has been allowed for new pipeline capacity.[120] This strengthens the potential of new capacity investments to earn returns. Pipelines and unconstrained capacity rights are crucial to bring gas to the market.

C) LNG

The rise in LNG spot and the effects of the Asian financial crisis of 1998 have somewhat impaired the willingness by LNG suppliers and LNG buyers to commit to long-term take or pay contracts with prices indexed to oil.[121] They have displayed a preference for short-term flexible contracts based on gas prices in the end user market. In addition, new LNG projects commit less than 100% of their plants total output under the SPC. However, the difficulties, which persist in developing an efficient spot market in LNG, have limited the potential of excess LNG capacity to displace long-term, take or pay contracts in that market.[122] Hence, despite the increase in the number of speculative LNG investments –liquefaction, tanker or regasification investments, long-term contracts still remain relevant.

D) Electricity

The dynamics of the electricity market have changed with full liberalisation. The UK ESI provides the illustration. PPAs and CFDs provide the basis for financing under

[118] Alberto, Cavaliere: *Competition in the Natural Gas Industry – European Liberalisation Issues and Regulatory Reform in Italy* posted on www.economica.anmi.it/eewz/cavaliere.pdf (last visited 17th April 2004).
[119] *Ibid.*
[120] Note 70.
[121] Newendrop *et al supra* note p. 37.
[122] *Ibid.*

the power pool.[123] With the pool replaced by NETA, market risk has become heightened. Whereas the pool provides some form of market, under NETA each generator must seek its own customers.[124] It is thus a polemic whether financing is possible for merchant power plants. The approach presently is for generators to contract less than 100% of their plants' output to the supplier. The inevitable implication for financing is that lender's may limit funding to the contracted kilowatts.

5. CONCLUSION

There is a view that the incentive for security of supply for large customers and industrial users should keep long-term take or pay contracts relevant within the liberalized energy markets although in a much more shorter and flexible form.[125] For instance, "it is important for major wholesaling companies to be able to include in their purchase portfolios an element of long term take or pay gas, which will assist in ensuring security and continuity of supply."[126] Also, the need to justify multi-billion dollar investments which energy projects sometimes require may also reinforce the relevance of long-term contracts in certain instances. Hence, such contracts may not need to be abrogated. What is however clear is that the scope of traditional long-term take or pay contracts has diminished considerably and the new form in which long-term take or pay contracts will co-exist with the spot market with its short term and medium contracts, hold serious implications for energy project financing.

Presently, sponsors of, and lenders to energy projects are seeking more realistic arrangements to support energy financing. For lenders, the implication is clear. The present approach by lenders to project financing of energy projects will definitely be re-assessed. Accordingly, a "thorough understanding of the pricing risks and a complete understanding of the dynamics of the floating price structures will be required for supporting debt structures."[127] There will be increased scope for hedging with portfolios of financial derivatives whilst a revision of the 80:20 debt to equity ratio as against equity, is envisaged.

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[123] Vinter *supra* note 2 p. 282, 283
[124] Stephen Murray: *Power Projects – Post NETA* in Energy Exchange, Winter/Spring 203
[125] Phillips *supra* note 20 p. 75.
[126] Brothwood *supra* note 4 p. 321.
[127] Steve, Mills and Chuck Zabrishire: *Liquid Opportunity* in Project Finance, Dec 2003 p. 11.

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