MPA Morrison Park Advisors

Capital Markets Impacts of Electricity Capacity Market Length of Contract

Prepared by Morrison Park Advisors
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1. Purpose & Preparation of the Report

The Province of Alberta has decided to pursue the development of a Capacity Market for electricity generation, to supplement the operation of the real time market that has been operating in the province for nearly two decades.

Several other jurisdictions have similar capacity markets, which have been in operation for a period of time. Arrangements and rules in each market are different, which presents Alberta decision-makers with an opportunity to consider which solution to capacity market design challenges may be better suited to Alberta conditions.

One particular issue to be addressed is the length of term of the capacity contract that results from the operation of the market process. In most markets, capacity contracts are awarded with a term set to begin a certain time forward into the future (usually three or four years). This allows the contract holder to make arrangements well in advance of the contract period in order to be able to fulfill the requirements of the contract. The length of time covered by the contract varies across jurisdictions, and in some cases varies according to the nature of the contract holder. Many markets distinguish between contract holders that will fulfill the contract on the basis of a generation facility that is in current operation, versus a generation facility that has yet to be built (and which presumably will be built during the forward period prior to the beginning of the contract).

In both the PJM and New England electricity markets, capacity contracts for existing facilities are limited to one-year terms. However, these two markets differ with respect to arrangements for facilities which are to be built prior to the commencement of the contract. In the PJM market, new facilities may secure a contract lasting up to a maximum of three years (under certain circumstances only), while in the New England market, contracts may last for up to seven years.

In the United Kingdom, a capacity market was recently developed and is being operated which has yet a different set of arrangements. Similarly to the PJM and New England markets, in the United Kingdom existing capacity is eligible for only one-year contracts (beginning four years in the future, in the case of the United Kingdom). However, if an existing facility must be refurbished, then it may be eligible for a three-year contract. New facilities may receive a contract lasting up to 15 years.

A final point of reference is Ontario. While the province has not operated a capacity market per se, several procurement processes were undertaken since 2003 which resulted in the awarding of 20-year capacity contracts for natural gas-fired electricity generation facilities.

The full range of potential contract terms, then, are:

- One year (principally existing facilities)
- Three years (new builds or refurbished facilities in certain jurisdictions)
- Seven years (new builds)
- Fifteen years (new builds)
- Twenty years (new builds)

The purpose of this Report is to examine the potential consequences of a choice between these various contract terms with respect to the availability and cost of financing.

Public information was collected to shed light on projects that have actually been awarded contracts and have proceeded to construction. In addition, non-public information was available to MPA through past activities of the firm, as well as through discussions that were initiated over the course of this assignment directly with financial participants in transactions across these jurisdictions. All such conversations were confidential, and not-for-attribution, but provide valuable insight into the current market for financing of electricity projects.

2. Financing New Electricity Generation Facilities

Transmission grid-connected electricity generation plants are typically large industrial facilities costing hundreds of millions to billions of dollars, and in many cases requiring years of planning, development and construction. Facilities typically are long-lived infrastructure with lifespans of 20 to over 100 years, depending on the particular type and design employed. In most cases, the initial cost of development and construction is a very large percentage of the full lifetime cost of the facility, and usually dwarfs all other types of inputs, such as labour and maintenance (however, in some cases such as natural gas-fired electricity generation plants, the cost of fuel can be a very substantial part of the full-life cost of the plant). The cost of the capital employed to construct such facilities, therefore, is a critical element in calculating their total cost over time, and hence the minimum expected price of energy that will be required to entice their development and construction.

Project Finance vs. Balance Sheet Financing

Electricity generation plants can be financed in two ways: through “project financing” (sometimes referred to as “non-recourse” financing), or through “balance sheet financing”.

An electricity generation facility is project-financed when capital providers rely exclusively on the financial performance of the single facility for their returns over time. Their investment is in one facility, and their revenues and returns exclusively come from that facility. In the event that the project does not perform according to expectations, they have no recourse to any other assets or entity, and must satisfy their demands from the project itself, if they are able to. This is analogous to a real estate mortgage, where a loan is secured by a specific parcel of land or a building, without recourse to any other asset or source of value.

Alternatively, many generation facilities are built, owned and operated by large companies based on their own financial resources, or balance sheet. Unlike project financing, no specific financial obligation attaches to any one facility. All of the facilities owned by the company are part of its portfolio of assets, and together they form the basis for the company’s business. Such companies may raise capital by issuing debt or equity securities from time to time, but not necessarily simultaneous with the development of any specific generation project.

	Project Financing	**Balance Sheet Financing**
Developer/owner/ operator	Can be any developer, regardless of size or means	Typically larger companies with substantial financial assets and capacity
Source of Debt	Typically institutional lenders, such as banks, insurance companies or pension funds	The developer/owner/operator provides all of the capital required for development and construction of the generation facility. Depending on its financial resources, it may choose to issue debt and/or equity securities in the capital markets to raise additional capital from time to time
Source of Equity	The developer/owner/operator will typically self-fund the initial equity during development of the project, and then may or may not bring in additional equity investors to fund construction, depending on the extent of their financial resources	
Credit Tests	The project must satisfy lenders' credit tests on its own, since loans will be "non-recourse" to any other party or asset. Lenders consider the project budget and risks of cost overruns, the certainty and volatility of expected revenue, expected operating costs, the ratio of expected cash flow to debt service requirements, the expected value of the asset in the event that the project defaults on its debt payments, etc.	Large developer/owner/operators are usually rated by credit rating agencies using a long list of financial criteria and tests. Equity analysts may offer opinions to market investors about the expected future value of the company's publicly traded stocks based on its expected future performance. The overall mix of assets in the developer/owner/operator's portfolio will be considered when assessing the ability of the company to satisfy the expectations of its lenders and investors. Any one project or asset may or may not be large enough or important enough to change the views of rating agencies and the capital markets, so developer/owner/operators carefully consider each investment they add to their portfolio
Equity Considerations	Similar tests as lenders, bearing in mind that creditors rank higher in payment priority, but do not participate in any enhancement in economic value	

Developer/owner/operator: Electricity generation developers can range from small companies working on a single project opportunity in one market, to global corporations owning and managing many facilities around the world. Typically, smaller companies rely on project financing to raise the money required to build projects, while larger companies may choose whether to rely on project financing or balance sheet financing. Some large developer/owner/operators insist that each project must stand on its own economic terms as a project, while others deliberately pursue a portfolio model, and treat all of their assets as a pool. A special category of developer/owner/operators consists of companies that pursue electricity generation as a support or add-on to their main business. These would include large industrial companies that build cogeneration plants (providing both heat and power) on the site of their facilities, or a small "behind the meter" electricity generation facility so that the industrial or commercial facility will not be dependent on the grid for electricity.

Sources of Capital: There are a wide variety of debt and equity providers that focus on new construction in the electric power industry. They are capable of assessing the economic potential of proposed electricity generation projects, and providing capital to those projects that meet their standards. Large developer/owner/operators that finance their new projects from their balance sheet rely on the capital markets to provide them with capital from time to time as required. Such companies typically are subject to constant scrutiny by credit rating agencies and equity research analysts, so that each of the company's new investment announcements is scrutinized to determine its impact, if any, on the overall financial portfolio and expected performance of the company.

Economics: The expected financial performance of a proposed electricity generation facility is critical to the decision to proceed with it. Each facility represents a large capital expenditure that, once built, is trapped in its location and cannot be moved. Financial failure of a generation plant can be catastrophic for its owners and capital providers, so estimating future profitability, and understanding the risks to that profitability, are a critical part of the development of any facility.

Project Finance in a Competitive Market Context

In electricity markets such as PJM, New England and the UK, and in the expected market design for Alberta, new electricity generation facilities can expect to win revenue through a combination of capacity market payments, energy market payments, and ancillary services market payments. Capacity market revenues are known at least somewhat in advance, because of the forward period and length of term of the various capacity auction processes, while the base case for energy revenues is that they are only known in real time (or day ahead, where that market feature is applicable). However, and this feature is critical to project finance, in some cases even energy revenues may be known somewhat in advance through participation in bilateral agreements, or "hedging" arrangements, for the price of delivered energy. In some markets, such energy hedging arrangements are as short as one to three months, while in other markets they can be as long as five years or more. In the latter cases, such hedging arrangements can provide critical support to developers of new projects. Finally, ancillary services markets (which are typically a collection of specific service sub-markets) have various features and arrangements of their own that differ from one jurisdiction to the next.

Theoretically, the total combined revenue received from the various markets for capacity, energy and ancillary services should cover all of the costs of an electricity generation facility:

a) Fixed operations, maintenance and administration costs (e.g., labour costs, equipment and supplies, property taxes, legal and accounting services, etc.);
b) Debt interest and principal payments resulting from financing the construction of the facility;
c) Fuel, which typically is directly related to the amount of energy produced;
d) Variable maintenance costs that depend on actual energy produced (e.g., wear and tear on machinery and equipment, or servicing costs related to total hours of production); and
e) Profit/return on equity for equity investors (including income taxes).

In a "perfect" world, from the perspective of project capital providers, revenues sufficient to cover elements a), b) and e) would be known in advance, when the decision to invest is made, while revenues received in real time would be sufficient to fully cover elements c) and d). This would make capital providers indifferent to the amount of actual production of the facility over time, and would essentially transfer all financial risk related to the investment in the facility to the consumers of electricity [since all "fixed" costs and profit would be guaranteed in advance, and variable costs paid only if production is required, consumers would be paying all of the costs associated with the existence and availability of the facility, whether it produces any electricity or not].

This kind of "perfect" arrangement might result from a "generation capacity + ancillary services capacity" auction whose length of term perfectly equaled the expected life of a particular class of electricity generation facility, and where the real time energy market was served only by generators who had the exact same cost of fuel. Obviously, such a market does not exist, since there are multiple different types of generation technologies participating in every market, with different expected useful lives, different levels of fixed and variable costs, different fuel costs, facing constantly evolving tax and policy regimes, and each with different return on equity expectations. In other words, every electricity generation facility faces many different kinds of risk, and profit/return on equity in particular is highly variable. Even for debt capital providers, who have superior claims to the cash flows from operation of the facilities in question as compared to equity investors, risks can be significant. Understanding and estimating all of these risks is a fundamental step in the decision to invest capital in a new project, at a specific price with a specific set of terms and conditions.

Project Debt Availability

Project Debt for new electricity generation facilities is available when lenders believe, with a reasonably high degree of certainty, that their investments will be repaid with a rate of interest appropriate to the amount of risk the lender is perceived to be taking. Fundamentally, this circumstance is achieved because the cash flows of a proposed project can be estimated within a certain range by a sophisticated analyst with access to market information and information about the specific project.

The relevant components of the cash flow analysis are:

- The source and reliability of the expected project revenues;
- Facility construction costs, and associated risks; and
- The cost of operating the facility (including fuel), and associated risks.

Risks associated with these cash flows are understood and perceived as manageable in reverse order to this listing. That is to say, operations and maintenance costs and risks are considered to be well known and highly manageable for most types of electricity generation facilities that would qualify for project debt. Construction costs and risks are also considered to be well known and subject to fairly accurate estimation, but given the history of unexpected challenges arising during construction projects, these risks are seen as somewhat less manageable. Finally, for electricity projects in competitive markets, estimating revenues and associated risks is considered to be the primary challenge.

Construction and operating risks can be managed by electricity projects in a variety of ways, from purchasing the appropriate insurance, to hiring experienced and sophisticated project managers, to assuming the purchase of high quality equipment from reputable and reliable vendors who warrant the performance of their products. Prospective lenders look for all of these types of indicators of risk management, and more. Typically, covenants to debt agreements require that all of these types of steps are taken, including setting aside financial reserves for unexpected challenges, in order to reassure lenders that their investment will be protected.

Revenues in a competitive market – particularly one which is divided into capacity, energy and ancillary services components – are the least predictable and most challenging feature of projects, from a lender's point of view. The securing of contracted revenues, and the nature of the contracts and counterparties involved, is fundamental to the successful arrangement of project debt.

Purely competitive real-time electricity markets, such as the real time energy-only market operated in Alberta over the past two decades, exhibit prices which are highly volatile and constantly evolving. While forecasters may predict the future of prices and levels of demand in those markets, energy projects choosing to participate in those markets do so entirely at their own risk. This level of risk is not appropriate for project debt, and hence project debt is essentially unavailable in such markets (as MPA has documented in the past for the AESO in previous Reports).

The availability of project debt is therefore directly tied to the availability of contracted revenues. Those revenues could be for capacity, energy, or ancillary services, but they must form a significant part of the expected revenue of the proposed facility if project debt is to be considered a financing option.

Notably, in the New England market, proposed new electricity generation facilities can win a seven-year capacity contract through a capacity auction. That affords seven years of revenue security for at least a portion of the revenue the facility will generate. In addition, projects might secure some level of additional revenue security based on energy market hedge contracts lasting up to five years, and possibly also through contracts to provide ancillary services for some period of time.

In the PJM market, capacity contracts are only one to three years in length, providing less revenue security than in New England for similar types of projects. However, the PJM market exhibits a very healthy energy hedging contract market for periods up to five years in length. Therefore, despite the fact that capacity contracts are only up to three years in length, new projects can obtain a significant degree of revenue certainty for up to five years.

In the UK, where capacity contracts can be up to 15 years in length, and in Ontario, where capacity contracts have been 20 years in length in the past, revenues are correspondingly secured for those periods of time.

Debt Impact of Contract Term

Assume for a moment that the contract term for a revenue agreement (i.e., a capacity contract, or an energy price hedge contract, etc.) is identical to the length of term of debt provided to the facility: what is the financial impact of that time period?

The length of term of a debt agreement has a powerful impact on the payments that must be made to service the debt over time. Longer terms will result in lower monthly, quarterly or annual payments. Alternatively, longer terms will allow a given monthly or annual payment to service a larger debt.

Impact of Length of Debt Term/Amortization

Term (years)	Annual Payment (thousands) For $1 million debt principal at 5% Interest	Maximum Principal that can be repaid by an $80 thousand annual payment at 5% Interest
20	$80	$1,000,000
15	$96	$833,000
10	$130	$620,000
7	$173	$464,000
5	$231	$347,000
3	$367	$219,000

In a market context, where contracts for capacity, ancillary services and energy price hedging may be given for different periods of time, the choice of a term for debt is not necessarily obvious. Lenders prefer maximum visibility to revenues that will support the repayment of their loans. Contracts from credit-worthy counterparties are the ultimate form of that visibility. If a contract provides “X” dollars per year of revenue to a project for a number of years, then lenders will typically choose to lend against a fraction of that contracted revenue.

Theoretically, lenders could provide project debt to a facility in different tranches that line up with specific contracts a facility has procured. For example, if a facility has a 3-year capacity contract, a 4-year energy price hedge agreement, and a 5-year ancillary services contract, lenders could provide the project with three tranches of debt that are amortized over each of those time periods. On the other hand, if for example a capacity contract lasts 7 years, an energy market hedge contract last five years, and an ancillary services contract lasts only 3 years, then a lender may choose to provide a loan with a 7-year term, but for a lesser amount than if all three arrangements lasted for 7 years. However, lenders are not only concerned about the security of specific revenue streams, they are also concerned about the overall financial viability of the borrower. If all revenue streams other than the contracted stream fail, then despite the contracted portion of revenues, the borrower may no longer be solvent, to the detriment of the lender. As a result, despite the value associated with contracted revenue streams, lenders are always taking into account the total potential revenue of the proposed facility.

In another scenario, a project may have a capacity contract that lasts 3 years, an energy price hedge contract that lasts five years, and no contracts in hand for ancillary services, but a strong expectation that some revenue will be gained from the ancillary services market because of the technical attributes of the proposed new facility. In that case, prospective lenders will have to undertake a tough-minded analysis about whether they believe claims and forecasts about the future of the capacity market beyond the three-year contract, and whether they believe forecasts and claims about the ancillary services market, and whether the new facility will be in a position to take advantage of those forecast prices. Depending on the risk tolerance of the lender, they may be willing to go up to the five-year term of the energy price hedge contract, even though the other revenue streams are far less certain. In a market like PJM, which is large, liquid, exhibits a variety of forms of contracting, and has developed a track record of performance over time, lenders have demonstrated some willingness to rely on revenue streams which are not fully contracted.

In general, the length of term of the longest contract sets the maximum term for the project debt that will be available, but given a variety of contract terms related to different revenue streams, the overall financing of a facility can be complex.

Counterparty

The counterparty to a revenue contract is critical for lenders: they make an assessment of the likelihood that the counterparty will be unable or unwilling to fulfill their side of the contract, and hence leave the project without the revenue it was expecting. Normally, the credit quality of the counterparty will be the limiting case for the perceived credit quality of an electricity generation project, and can even affect the length of term of the debt that can be raised.

For example, if the counterparty on a capacity contract is a government agency that is rated A+, then the maximum rating possible for the new project is effectively A+. However, the project includes risks (especially, e.g., construction) that are in addition to counterparty risk, so the project may ultimately be perceived to have a lower credit quality than the contract counterparty. Assuming that the government agency offers a 10-year contract, then the limiting term of the debt would typically also be 10 years, because there is a limited likelihood that a government agency would seek to cut short or walk away from a contract. In general, capacity market and ancillary services market contracts – which are backed by a mechanism to recover costs from the entire customer base in the market – are considered to be extremely credit-worthy, and hence not a significant impediment to project financing.

Bilateral hedging arrangements with counterparties in the energy market, however, are a very different issue. The counterparty may be an energy trading company, or a division of a bank or other financial house, or perhaps just a large industrial consumer that wishes to lock in its energy costs. Each of these parties may have a different credit rating, and all of these types of entities have failed or walked away from contracts in the past, particularly in the event of financial crises. As a result, not only would the credit rating of the counterparty limit the credit-worthiness of the project, but lenders might also be reluctant to lend against the full term of the revenue contract with the counterparty. The result might be a four-year loan agreement against a five-year hedge contract, for example.

Sweeps and Their Impacts on Cost of Equity and Overall Cost of Capital

Debt agreements sometimes include a "cash sweep" feature. In these cases, lenders provide debt to a project, and calculate a schedule of minimum payments over time for repayment of the loan. However, the degree of security of the cash flows may be less than desired, for example if the debt is a second tranche, that sits "behind" a senior debt in the capital structure of the project. In exchange for taking this higher degree of risk (i.e., lending in a situation where free cash flow available to repay the debt is less robust than it is for a senior debt), the lender may not only require a higher interest rate on the loan, but also require that at the end of every year all of the free cash available in the project be used to repay the outstanding debt principal (sometimes with exceptions for certain administrative or management fees payable to equity holders).

In effect, a "cash sweep" means that equity holders will receive no return at all until all of the debt principal of the loan with the sweep feature is repaid. Existence of such features not only affects the amount of equity that is necessary for a project, but also the return expectations for equity, and the cost of capital for the project as a whole.

Consider three versions of a project which requires $1 million of capital (ignore tax issues in this simple case) over a total period of 20 years:

A. $500 of debt at 4% interest, and $500 of equity at a target 10% return

B. $500 of senior debt at 4%, $200 of junior debt at 7%, and $300 of equity at 10%

C. $500 of senior debt at 4%, $200 of junior debt at 7% and with a cash sweep, and $300 of equity, also at a target 10% return

In the first case, version A, the cost of the debt would be $37 thousand per year, and the target equity return would be $59 thousand per year, for a total cost of capital of approximately $96 thousand per year.

In the second case, version B, since somewhat lower cost debt is being substituted for part of the equity, the total cost of capital would be less. This would allow the project to compete in the marketplace by offering a lower price for its capacity, which would be good for customers in the market (and make it more likely that the project would win a contract in the first place). Senior debt would still be $37 thousand per year, junior debt would be $19 thousand, and equity would be only $35 thousand, for a total of approximately $91 thousand. This represents a savings of $5 thousand per year as compared to version A.

In the third case, version C, the junior debt will not be paid a fixed amount each year, but instead would receive all of the available cash every year until the loan is repaid. No cash flow would be directed to equity until that happens. The senior debt would continue to receive $37 thousand per year over 20 years. The junior debt would receive $57 thousand dollars per year in principal and interest payments for four years, and less than $10 thousand in the fifth year to pay off the remainder of the interest and principal outstanding. Equity would receive nothing in for the first four years, but in the fifth year would receive $48 thousand, and from the fifth to the twentieth years would receive $57 thousand. The internal rate of return to the equity investor would be the target 10%. The total cost of capital in this case is slightly less than $94 thousand per year, effectively in between the first two cases.

From this example, it can be seen that the existence of a cash sweep feature is "costly", in the sense that it is equivalent to a higher rate of interest on debt (since the total annual cost of capital is higher in version C than it is in version B).

However, a less obvious consequence in addition to the increased cost of capital is that it is unlikely that an equity investor would be satisfied with the version C scenario as opposed to the scenario in version B. In version B, the equity investor contributes $300 thousand in capital, and receives a target return of $36 thousand per year beginning immediately in year one. Sometime in the middle of the eighth year of the project, the equity investor has recouped its investment (i.e., the "payback period" of the equity investment is approximately 8.5 years). In the third case, however, the equity investor receives nothing for the first four years, and then begins receiving higher payments. The initial investment of $300 thousand is not recouped until sometime in the tenth year (i.e., the payback period is approximately 10.4 years). From the equity investor's perspective, even though the nominal rate of return of the two scenarios is the same mathematically, the third scenario is "riskier" than the second scenario (because payback occurs later, and leaves more time for bad things to happen in the intervening years). The investor is likely to require a higher rate of target return on equity if the sweep feature is present is present in the debt arrangements.

In fact, with a higher target rate of return on equity to compensate the equity investor for taking more risk, it is possible that the total cost of capital for the project including junior debt and a cash sweep, could approach or even exceed the cost of the scenario in version A, with only senior debt and equity. If that is the case, then why bother going to the trouble of arranging the junior debt in the first place? Possibly because there is only so much equity risk capital available for these types of projects, so all available capital resources must be pursued by project developers.

Credit-worthiness, Lender Limitations, and Interest Rates for Project Debt

Whereas the visibility and reliability of revenues are fundamental to the length of term for project debt, the pricing of that debt in terms of the applicable interest rate captures a much broader view of the risks associated with the project. Lenders must take an all-encompassing view of the project's expected cash flows, and all of the potential threats to those cash flows, in order to come to a view on the appropriate interest rate. Most lenders have internal limitations on the credit-worthiness of projects that they are willing to fund. For example, one lender may be willing to provide a loan to a B+ project, but not to a B project, while another might be willing to go so far as a B- project. Interest rates, not surprisingly, are inversely related to the perceived credit quality of projects.

Notably, while the nomenclature of credit rating agencies is used to the describe the credit-worthiness of projects (i.e., A+, or BB, or B-, etc.), projects are not actually rated by a credit rating agency. Lenders themselves will perform an analysis on the proposed project, and will determine that the loan would be "equivalent to" a rating of "X", in order to allow for benchmarking of the cost of credit in the marketplace. For example, if "B+" loans are currently being made at "LIBOR + 300 bps", and a proposed project were considered to have "B+" credit-worthiness, then it would be offered an interest rate in the range of "LIBOR + 300 bps" (plus the additional rate required for the term of the loan, whatever that may be, since LIBOR generally refers to rates for short-term arrangements only).

Another limitation that may arise from the perceived credit-worthiness of a loan (or lack thereof) is on the willingness of a lender to take a large portion of the total debt of the project. For example, a lender may be willing to only support a B+ project if there are at least three other lenders that have taken the same view (i.e., the project will be supported by a syndicate of lenders, who have each taken one quarter of the total debt). Presumably, the lender would prefer to invest a smaller amount in four different B+ projects, rather than a larger amount in one B+ project. This would reflect the fact that B+ projects are risky (certainly riskier than A+ projects), and hence lenders seek the safety of portfolio diversification in order to better protect themselves from project failure. Along a similar line, lenders in a "B" project may want to be a part of a syndicate of six, rather than four, in order to spread risks even further. [Note that these examples are illustrative only, and are not meant to be actual requirements or market tendencies at any given time.] The need to organize syndicates of lenders to invest in projects makes the projects that much more difficult to successfully develop, and limits the total number of projects that might be possible in any given market, at any given time.

Debt vs. Equity

Considered from the outside, a critical feature of projects appears to be the relative shares of total capital costs provided by debt investors vs. equity investors (or the various flavours of each of these, as there may be hierarchies within each group on any given project). However, this split is actually the result of consideration of all of the issues described above, rather than a driver. For example, for a given project a developer may believe that the target price for a capacity auction (or energy hedge contract) may be "X". At that price, how much revenue will be generated for the project, and for what period of time? Given the expected costs of the project, how much EBITDA will result? At that level of EBITDA for that period of time, how much senior debt can be supported, at what interest rate? How much junior or mezzanine debt, and at what interest rates and with which conditions, sweeps, etc.? How much equity would in the end be required, and what would the characteristics of the return to equity be? Do these tranches of capital happen to be reasonably available in the market from a variety of lenders and/or equity providers? If so, then a bidding group can be constructed along these lines, if not, then the target contract price must be reconsidered, and all the calculations prepared again. The process is iterative, and disciplined by competition amongst developers and capital providers. The debt:equity ratio in a project is the result of all of the factors considered, and not the starting point (as may be the case in the fictional examples assumed above for illustrative purposes).

As market conditions change, the nature and characteristics of "financeable" projects will change, including the debt:equity ratio of successfully built projects, and the costs of capital that are associated with each class of capital employed. The process is complex, and is just as much affected by conditions in the electricity markets, as by conditions in the capital markets.

Balance Sheet Financing in a Competitive Market Context

Some projects are financed, constructed, owned and operated by large companies that own and operate multiple electricity properties, often located in more than one jurisdiction. In these cases, the proponent may choose to avoid project debt entirely, and instead finance the project from its own capital resources. Those resources might include the issuance of debt from time to time, but that debt would not be secured against any particular project, instead being secured by all of the assets and cash flows of the company. In effect, the debt:equity ratio and cost of capital of all of the individual projects in the company's portfolio are assumed to equal the company-wide debt:equity ratio and cost of capital.

Balance sheet-based (or "strategic") developers must still undertake all of the same analysis of new construction opportunities, both financial and risk-related, as project developers. They must determine the expected cash flows from a new development as best as they are able, in order to decide whether the development is sufficiently lucrative to warrant the company expending what are always limited capital resources. Moreover, they must consider how market analysts will interpret the investment and possibly revise their outlooks for the company, and company manages must consider the impact that a new investment will have on their company's overall pooled financial results under a variety of possible scenarios. If risks are so great that the outcome would be not only uncertain, but potentially large enough to negatively affect the overall view of the company's risk exposure, then the project may not be approved by the company's decision-makers.

Unlike project-financed based developers, strategic developers do not need to secure agreement from lenders for every individual project. The developers themselves own and manage a portfolio of assets, and are measured by the debt and equity markets on the basis of the overall performance of their company's total portfolio. In essence, they are internally pursuing a portfolio management and portfolio diversification approach similar to what lenders might pursue if they made loans to a variety of projects at different levels of risk, located in different markets with different features. This flexibility is why strategic developers can consider building new projects in markets where project developers simply cannot secure financing. In essence, they are willing to invest some capital in higher risk/higher reward jurisdictions, as long as they also are invested in some different jurisdictions that have a lower risk/lower reward profile to "balance" their portfolio. This characteristic means that even in very high risk jurisdictions there may be one or a few large players willing to participate.

However, while portfolio risk management strategies allow large players to be flexible in choosing which markets to participate in, it should be noted that there are only so many of these large players available. If a market is designed with very little revenue security for investors, then only the small pool of large balance sheet investors will be able to participate in it. On the other hand, if a market is designed with a greater degree of revenue certainty, then potential participants will not only include the small number of large strategic players, but may also include some developers who will rely on project financing methods of securing capital. Market design choices are therefore fundamental to issues such as the range of potential capital providers available, and the likely number of participants who will engage with a market over time.

3. Recent Market Experience

In the past five years of capacity auctions, PJM approved capacity contracts for approximately 21,000 MW of proposed new electricity generation facilities, and ISO New England approved approximately 3,600 MW. These contracts were for a range of generation technologies and facility types, across all classes of proposed owners and operators.

In its most recent auction (for 2020-2021 delivery), PJM cleared a total of more than 165,000 MW of capacity resources, comprising existing and new generation resources, imports, demand response resources, and electricity efficiency resources. On average over the past five years, the new generation resources portion has comprised less than 3% of total capacity that cleared.

In New England, approximately 36,000 MW of total capacity across all resources cleared the most recent auction (for 2020-2021 delivery). On average over the past five years, the new generation resources portion has comprised approximately 2% of total capacity procured.

New England

ISO New England offers proposed new electricity generation projects capacity contracts lasting up to 7 years, beginning in the delivery year three years after the capacity auction.

Over the past five years, eight capacity contracts have been awarded to projects over 90 MW in size (ranging up to 725 MW). Five of these contracts were won by large "strategic" electricity sector players who finance projects from their balance sheet. These include, among others:

- Dynegy
- Exelon
- NRG
- PSEG

The other three capacity contracts were won by entities likely to project finance the construction of a new facility, and two of these have successfully arranged project financing. The third facility does not appear to have achieved financing as of this time, as it has been suffering through a series of delays and challenges.

PJM

PJM offers proposed new electricity generation projects capacity contracts lasting up to a maximum of 3 years under certain special conditions, beginning in the delivery year three years after the capacity auction, with a base case of one year capacity contracts. In addition, the PJM market is host to an active bilateral contracting and trading market for energy hedges lasting up to five years. Crucially, this hedging activity actually extends the timing of revenue certainty for projects beyond the three-year limit of capacity contracts.

As noted, the PJM capacity market is approximately five times larger than the New England capacity market, as measured by MW of total capacity auctioned. In the past five years, there have been more than 25 capacity contracts awarded for new electricity generation projects, typically for facilities of between 300 MW and 1000 MW in size, with a few outside this range. Of these 25 new facilities, 20 have been reported to be project-financed, and in most cases these facilities have been larger than similar projects in New England.

Only a small number of contracts in the PJM market have been awarded to large "strategic/balance sheet" companies. In most cases, these companies were underbid by aggressive project developers, who arranged projects including between two and five equity providers, and lending syndicates of up to 16 different financial institutions.

A wide variety of project developers have participated in the PJM market, often by jointly developing and providing equity to projects which ultimately received debt from project lenders.

Strategic players have also participated in new project development in the PJM market, including Dominion Energy and PSEG, but the vast majority of new electricity generation facilities have been developed by entrepreneurial project developers supported by project financing.

UK and Ontario

In the UK, capacity auctions have only been running for three years. Several 15-year contracts have been awarded for construction of large new electricity generation facilities (but many more contracts were awarded to small distributed facilities based on several electricity generation and storage technologies).

In Ontario, over the past 15 years more than a dozen capacity contracts have been awarded for the construction of large electricity generation facilities (gas-fired), virtually all of which have been for 20-year terms. Most of these new facilities were project-financed, but a few were developed and are owned and operated by large strategic players. However, it should be noted that these contract awards did not occur through an annual capacity auction, but a more sporadic and unpredictable RFP procurement process occurring from time to time, so direct comparison of market players and outcomes is less than totally fair.

Typical Project Financing Features

Term

As would be expected, the term of debt across the record of projects winning contracts over the past five years in the PJM and New England markets, and confirmed by industry participants contacted directly for this Report, is typically coterminous with contracts that developers have won or arranged for their projects.

In New England, capacity contracts extend out to 7 years beyond the three-year construction period, which allows debt to be arranged for up to that maximum amount of time. However, it should be noted that capacity payments are only a fraction of the total revenue expected by facilities, and so not all debt will rely solely on the capacity contract. Energy hedging arrangements are available in the New England market, and these may provide additional support to the projected finances of new projects.

PJM presents a more interesting case: typical debt arrangements across the many projects that have received financing in the past five years are for a three-year construction period, plus four or five years. This total 7 to 8-year debt term actually extends beyond the maximum three-year capacity contract period (three years forward, plus a one, two or three-year term for the capacity contract), and instead depends more on the successful contracting of hedge agreements for energy prices (whether revenue hedges or contract for differences). This spontaneous market development is not under the control or direction of the market operator, but is instead entirely self-propagating.

Given the unorganized nature of the market for energy price hedges, it is entirely conceivable, however, that a market shock could at some point curtail this activity (as happened in the past to energy market activity after the Enron collapse in 2001, and after the financial crisis in 2008), which would in turn cause the project finance market for 7 to 8-year loans to dry up. If that were to occur, then it would be expected that new capacity would be financed by strategic players rather than project developers, and with a lower level of competition than has recently been the case. Alternatively, in such an event the market operator might give consideration to lengthening the term of the capacity contract to lend further support to the project finance market, as in New England or elsewhere.

Another consideration with respect to the experience in the PJM market is that capital markets over the past five years have been extremely favourable. Interest rates have been at historic lows, and capital has been plentiful because of central bank efforts to increase the money supply to stimulate economic recovery from the lingering effects of the financial crisis. While many projects in the PJM market have successfully secured debt in these conditions, despite the short term of PJM capacity contracts, it is not clear that this will continue to be possible if interest rates rise and capital availability is somewhat constrained.

On the other hand, experience in the UK and in Ontario with longer capacity contract terms of 15 or 20 years generally confirms that debt terms will follow capacity arrangements with respect to the length of contract terms. In Ontario, the experience of numerous facilities constructed under 20-year capacity contracts is the availability of 20-year project loans.

Equivalent Credit Rating

Though there is sparse public reporting of the credit-worthiness of projects, given that most are private arrangements, there is some information available that projects were in general deemed by lenders to be equivalent to BB- through B+, B, or B-. Several industry participants confirmed that their institutions were willing to consider opportunities today that would qualify as B or B+ projects.

The threshold for "investment grade" credit is "BBB-", so the project finance market for electricity facilities in the US today is universally sub-investment grade. This has the important consequence that many large financial institutions, such as pension funds and insurance companies, are not allowed to provide loans because of internal restrictions on taking sub-investment grade risk. The market for project debt in the New England and PJM project finance markets is therefore substantially restricted as compared to other lending opportunities, such as for 20-year renewable energy contracts, or 20-year contracts that were let in Ontario over the past 15 years (all of which are investment grade, and have attracted correspondingly low cost debt from long-term lenders).

Nonetheless, in the PJM market at least, a specialized and competitive industry has developed around arranging sometimes complex debt agreements for electricity project loans with sub-investment grade credit-worthiness. Despite the absence of many lenders who might be noticed in other lending markets, there has been sufficient participation by the lending community to maintain a steady flow of financing arrangements for the past five years.

Notably, the participants in the lending syndicates for many of the projects have been foreign banks, rather than domestic North American banks, which suggests that domestic banking regulation may have some impact on the willingness of domestic banking institutions to participate in these transactions. For example, public information is available indicating that the following lenders participated in more than five syndicates for new projects over the last five years:

- BNP Paribas

- Credit Agricole
- Industrial and Commercial Bank of China
- Mitsubishi United Financial Group
- Societe Generale

In addition, non-bank financial institutions in the United States have played a prominent role, including:

- CIT Group
- GE Financial

Several US commercial banks have occasionally appeared as members of several syndicates, but in a significant majority of cases debt capital has not been provided by traditional domestic banking sources.

Interest Rates

Consistent with the sub-investment grade credit-worthiness of the project financings, interest rates have been significantly higher than those for long-term renewable energy contracts, for example. Typical rates quoted have been in the range of 300 to 400 bps above LIBOR short-term money, plus appropriate swap rates for the length of term being quoted. This has resulted in rates in the range of 5% to 6.5% for seven to eight year terms, for example.

By comparison, in Canada, 20-year debt for renewable energy agreements (and for 20-year capacity contracts in Ontario) has been priced at substantially lower rates, despite the longer term.

All of these rates are dependent on the underlying movement of interest rates, of course, and as the overall credit market has seen rising rates over the past year, it should be expected that rates for the project finance market will also be trending upwards.

Structure of Debt Arrangements

Most successful project financings in the New England and PJM markets have included multiple layers of debt with varying terms and conditions. Few projects, if any, have been financed with a single term loan structure. Instead, projects might have a tranche of underlying fixed rate term debt, with a tranche of subordinate floating rate debt above, and sometimes a third layer of even higher risk debt above that. These complex arrangements are difficult to coordinate, and typically the projects entail the services of multiple brokers and financial market advisors. This complexity and requirement for additional service providers adds to the cost of the projects, which ultimately must be factored into the prices bid into capacity auctions, and hence passed on to ratepayers in the price of contracts that underlie these financings.

Cash Sweeps

Not surprisingly, given the complex structure of the debt arrangements described in the preceding paragraph, cash sweeps are common for at least one tranche of debt in almost every project financing. This is critical, because it places limits on the equity market for project financings as well: equity investors in these projects know, because of the use of cash sweeps by project lenders, that no return to equity will be delivered for at least the first several years of operation of the facility.

As was discussed in Section 2 of this Report, the use of cash sweeps by lenders effectively increases risks borne by equity providers, and increases the resulting cost of equity. This translates into an overall higher weighted average cost of capital for projects with shorter capacity contract terms (rather than longer contract terms), and hence drives the market price for energy upwards (at least for the period of time covered by the contracts).

The other consequence of the use of cash sweeps by lenders is that it limits the range of equity investors that may be interested in these markets in the first place: investors who are focused on a steady stream of cash dividend yields will avoid the project finance market, because of the uncertain nature of the timing for yields to begin (i.e., after the full payment of principal on certain tranches of project debt). Again, a smaller market of potential investors generally leads to less competition for investment opportunities, and hence higher expectations for equity returns, and upward pressure on electricity contract prices. Alternatively, longer capacity contracts would make cash sweeps for debt less necessary, and would also serve to push down the cost of equity for these projects.

Debt : Equity

In the market for 20-year renewable energy contracts (and previously for 20-year capacity contracts in Ontario), it is not uncommon to see debt ratios at in-service of projects in the range of 75%, or even more in some cases (for example, in solar PV projects debt can be significantly higher).

In the project finance market in New England and PJM, debt ratios that have been publicly reported have been significantly less than 75%, but are still often reported to be higher than 50%.

Market participants contacted directly for this Report have stated that they will not generally provide debt greater than 40% to 50% of the total in-service cost of a project; however, this view is somewhat different from publicly reported figures for the past five years (when many projects appear to have arranged debt greater than 50%). This difference may be explained by the current rising interest rate environment, or a more recent tightening of the market, or perhaps by the underreporting of total project costs in the past (which would result in a higher apparent debt ratio based on publicly reported debt amounts).

Nevertheless, it should be recalled from Section 2 that five to seven-year debt amortization periods, as compared to twenty-year amortization periods, will support less than half the amount of debt principal at similar interest rates. The project finance market has higher interest rates than the 20-year debt market for renewable energy contracts, for example, but still appears to support debt ratios above 50%. Cash sweep provisions in many debt arrangements effectively result in much higher payments to debt providers in the early years of projects than would be the case in 20-year debt agreements, which helps to explain the higher levels of debt financing than would be expected given the shorter terms and higher interest rates. These arrangements also result in costs of capital that are higher than they would otherwise be under long-term debt arrangements.

In a few cases, market participants have suggested that at least some minimal amount of debt is not fully amortized within the contract period, but is instead expected to be refinanced at the end of the debt term. The existence of any “bullets” in the debt agreements which require refinancing at the end of contract terms suggests that lenders may have at least some confidence in the longevity and robustness of the markets in question. However, the cost of taking this risk is embedded in the higher rate of interest that is required from these short-term contracts, as compared to longer-term agreements.

Number and Nature of Lenders

Every project finance arrangement for which information is publicly or privately available for this report exhibits at least three, and in several cases more than a dozen lenders. It is clear that while lenders are willing to participate in the project finance debt market, they strictly limit their exposure to any one project, preferring to spread the risk they are taking in the sector across multiple projects. This situation has important consequences, in that any new market that wishes to tap into the project finance market cannot expect to begin with only a few market participants in the debt market, and expand over time. If successfully financing any single project requires the participation of multiple lenders, then multiple lenders must be attracted into a new market from the outset.

As noted above, the participants in the New England and PJM project finance market include multiple international banks from Europe, Japan, China, Korea and other countries, as well as a certain number of non-bank financial institutions from the United States, but displays a significant absence of US or Canadian banks. As Alberta makes arrangements to launch its capacity market, attention should be addressed to ensuring that foreign bank and non-bank institutions are kept apprised of developments, so that they can be quickly brought up to speed about the attributes and financeability of projects that win capacity contracts in Alberta.

Number of Equity Providers

In keeping with the syndicated nature of the debt arrangements for project-financed deals, most successful projects over the past five years reportedly include between two and four equity providers. The fractional participation of a number of equity providers across several projects is a clear indication that these equity providers are pursuing a portfolio risk mitigation strategy similar to that of banks in the lending market.

Participants range across North American and International equity funds, and offshore strategic players (North American strategic players typically fund entire projects instead of participating in consortiums, and do not use project finance). Notably, pension funds and insurance players, who are absent from the project debt market, are present on the equity side of some of these transactions (presumably their internal rules do not restrict participation in riskier opportunities from an equity perspective, but are restrictive with respect to debt).

[Note: in the market for 20-year debt that has developed around renewable energy projects, for example, insurance companies and pension funds have provided an enormous amount of debt capital. In fact, these lenders far outstrip the participation of commercial banks, who have not been as deeply involved in the 20-year debt market. However, in shorter-term capacity contract environments, where debt is both riskier and shorter-term, pension funds and insurance companies have been almost completely absent from the lending side, but have participated on the equity side. North American commercial banks, on the other hand, have been only minimally present in both long and short-term markets for electricity project debt. Apparently, they have been too expensive as compared to insurance lenders in the long-term debt market, for example, and they have been too risk-averse as compared to foreign banks and non-bank lenders in the shorter-term debt market.]

One notable group of participants on the equity side of project finance arrangements is equipment suppliers such as Siemens and Sumitomo (who also occasionally participate on the debt side as well). Major equipment suppliers have taken a fractional ownership position in several project-finance situations over the past five years, at least initially. This can be understood as a way that equipment suppliers can encourage the purchase of their equipment (and enlarge the size of their own target market), without the need to reduce their prices. This equity participation makes it easier to successfully arrange the financing for a project, and get a project to completion. Equipment providers seldom retain that ownership stake for the long term, but instead liquidate that position at some point after the project has achieved in-service and been de-risked (they recycle the funds into other project opportunities).

4. Implications for Alberta

Alberta's electricity market is approximately one tenth the size of PJM, and less than half that of New England, as measured by average load and total available capacity. Nevertheless, the real-time energy market in Alberta exhibited substantial levels of both competition and new construction over the course of more than 15 years of continuous operation. However, it is important to recognize that the Alberta energy-only market benefited from four characteristics over that span of time:

- A roster of strong, local incumbent strategic players who had diversified portfolios of assets in other jurisdictions or in adjacent lower-risk businesses such as electricity distribution;
- Significant demand for power from large industrial customers who were also candidates for combined heat and power projects, which are inherently lower risk projects because their capital cost and resulting revenues is diversified across both electricity and heat supply;
- A group of long-term PPAs that underpinned the economics of a significant amount of generation capacity that pre-existed the creation of the market; and
- Extraordinary policy stability.

While the first characteristic continues to obtain, the forecast for future combined heat and power projects has dimmed somewhat with the slowdown in expansion of the Alberta Oilsands. The collapse of the PPAs, the decisions of the government to require the closure of all coal plants, directly procure new renewable energy facilities and increase carbon taxes have decisively changed the broader environment for power projects in the province, curtailing the conditions under which previous investments were made.

Alberta expects that over the next twenty years, approximately 10,000 MW of new electricity generation facility construction will be required across all technologies. Some of this will be renewable energy facilities supported by long-term contracts, and some may be facilities that would be better supported through capacity contracts. The relatively modest size of this need, especially when considered on an average annual basis over twenty years, suggests that it is unlikely that many new local developers will arise in Alberta to provide the development and financing for projects that will be necessary (other than existing incumbent strategic players), given how challenging it is to sustain a development business over time. Market participants currently operating in other jurisdictions must be relied on to enter the Alberta market and pursue new opportunities in Alberta if broader competition is to be fostered. This places a premium on making rules and structures in Alberta at least similar to those operating successfully elsewhere.

New England has seen the construction of a number of projects over the past five years, and PJM substantially more, consistent with its overall much larger size. Despite New England's longer capacity contract term, project finance activity has been less successful, and instead strategic players have captured a majority of contract opportunities (but project finance developers competed in every auction). This outcome is neither good nor bad from an electricity market perspective: the only relevant question is whether customer needs are being served. PJM's capacity contract term is shorter, but energy price hedging activity is robust and actually longer term than capacity market contracts, and project finance opportunities appear to have responded to the opportunities created by that spontaneous hedging market activity.

In the height of Alberta's energy-only market, energy contracts seldom ran longer than three years. For whatever reason, a thriving five-year or longer hedging market never developed, and today hedging activity is extremely limited. It would appear unlikely that in the face of this history, and given the changes in the Alberta electricity market over the past two years, that a longer-term hedging market would spontaneously arise in Alberta to match that in PJM, at least in the near term. It would seem, then, that Alberta's capacity contract term will drive the potential availability of project-financing debt terms, as it does in New England (and the UK, and Ontario). Were Alberta to select a three-year capacity contract term, then it appears likely that project financing options would be very limited, if available at all, and would likely be expensive in terms of cost of capital. Conversely, choice of a longer term for capacity contracts likely would give rise to project-financing opportunities of a longer duration, and reduce the overall net cost of capital for new generation projects.

The relationship should be considered direct, but not automatic or absolute: choice of a one or three-year capacity contract term is likely to result in only a few large strategic players competing for the opportunity to construct new facilities in Alberta. Project finance will not likely be possible in that type of an electricity market. With a seven-year contract term, project finance opportunities similar to what has been available in New England and PJM may also become available in Alberta (potentially supported by the same or similar financial players). In addition, more non-incumbent strategic players might find it attractive to compete for such opportunities in Alberta. At longer contract terms of fifteen or twenty years, such as those in the UK or in the past in Ontario, it should be expected that project finance developers would dominate the market, supported by a very broad range of debt and equity providers from across North America and around the world.

Caveats

Despite the success of the project finance community over the past five years, particularly in the PJM market, it should be noted that this window of time has benefitted from historically low underlying credit costs, and broad availability of all types of credit in the financial markets. Past performance is of course no guarantee of future success, and as broad capital markets drivers perhaps change direction in the future, the impacts on the project finance market are unpredictable. The market participants in both equity and debt who have contributed to the success of the project finance market in PJM and New England will not necessarily continue to be so involved, and the fact that a relatively small group of players have participated in many of the most successful transactions in those markets suggests the possibility that this activity has been a unique confluence of circumstances, the durability of which may be open to question.

There is no question, based on the evidence collected and the responses of market participants, that the overall cost of capital of new electricity generation projects is directly affected by the length of term of underlying contractual agreements. The longer the contract, the lower the total cost of capital, both because of a reduction in risk associated with the project (from the funders' point of view), and because the number of players and level of competition in the funding community increases. On the other hand, a longer contract term will also increase risk exposure to consumers who ultimately must fulfil the contracts through the price they pay for energy. This "risk-reward" determination is built into the selection of contract term, and sets the table for subsequent investment activity, even if it is not immediately apparent that the policy choice is so directly determinative of overall electricity market costs.