Criteria | Corporates | Project Finance:

Key Credit Factors For Power Project Financings

September 16, 2014

(***Editor's Note:*** *This article has been superseded by "Sector-Specific Project Finance Rating Methodology," published Dec. 14, 2022, except in jurisdictions that require local registration.)*

1. This article presents S&P Global Ratings' methodology and assumptions for rating power project financings and aims to help market participants better understand the key credit factors in this sector.

2. This article is related to our global project finance criteria (see "Project Finance Framework Methodology," published Sept. 16, 2014) and to our criteria article "Principles Of Credit Ratings," published Feb. 16, 2011.

SCOPE OF THE CRITERIA

3. These criteria apply to all electricity generation and transmission power project financings (referred to as "power projects" hereafter).

SUMMARY OF THE CRITERIA

4. These criteria specify the key credit factors relevant to analyzing the construction phase stand-alone credit profile (SACP) and the operations phase SACP for power projects, which we rate in accordance with "Project Finance Construction Methodology," published Nov. 15, 2013, and "Project Finance Operations Methodology," published Sept. 16, 2014.

5. As indicated in tables 1 and 2, factors marked with an 'X' in the key credit factor column provide additional guidance to the sections of the "Project Finance Construction Methodology," Nov. 15, 2013, and "Project Finance Operations Methodology," Sept. 16, 2014. For factors not marked with an 'X' in the key credit factor column, the information provided in the "Project Finance Construction Methodology," Nov. 15, 2013, and "Project Finance Operations Methodology," Sept. 16, 2014, apply. This KCF also provides the assumptions for determining our base and downside cases for power projects.

Table 1

Power: Areas Of Additional Guidance

	Where assessed	
Factors	**Construction phase criteria**	**Key credit factor**
A. Construction phase business assessment		
1. Technology and design risk	X	

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Table 1

Power: Areas Of Additional Guidance (cont.)

	Where assessed	
Factors	**Construction phase criteria**	**Key credit factor**
a) Technology risk		
i) Technology track record in this application	X	X
ii) Technology performance match to contract requirements and expectations	X	X
b) Design cost and variation risk		
i) Degree of design completion and costing	X	
ii) Design complexity	X	X
2. Construction risk		
a) Construction difficulty	X	X
b) Delivery method		
i) Contractor experience	X	
ii) Degree of contract risk transfer	X	
3. Project management	X	X
4. Adjusting the preliminary construction phase business assessment	X	
B. Financial risk adjustment		
1. Funding adequacy (uses of funds)	X	X
2. Construction funding (sources of funds)	X	X
C. Construction phase stand-alone credit profile	X	
1. Construction counterparty adjustment	X	
D. Other factors	X	

Table 2

Power: Areas Of Additional Guidance

	Where assessed	
Factors	**Operations phase criteria**	**Key credit factor**
A. Operations phase business assessment		
1. Performance risk		
a) Asset class operations stability	X	X
b) Project-specific contractual terms and risk attributes	X	
i) Performance redundancy	X	
ii) Operating leverage	X	
iii) O&M management	X	
iv) Technological performance	X	
v) Other operational risk factors	X	
c) Performance standards	X	X
d) Resource and raw material risk	X	X

Table 2

Power: Areas Of Additional Guidance (cont.)

2. Market risk		
a) Market exposure (including downside-case guidance)	X	X
b) Competitive position	X	X
3. Country risk	X	
B. Determining the operations phase SACP		
1. Preliminary operations phase SACP (including base-case guidance)		
2. Adjusted preliminary operations phase SACP		
a) Downside analysis	X	X
b) Debt structure (and forecast average DSCRs)	X	
c) Liquidity	X	X
d) Refinance risk	X	X
e) Projects without fixed contractual maturity dates	X	
f) SACPs in the 'ccc' or 'cc' categories	X	
3. Final adjustment to arrive at the operations phase SACP	X	
a) Comparable ratings analysis	X	
b) Counterparty ratings adjustments	X	

O&M--Operations and maintenance. SACP--Stand-alone credit profile.

6. This paragraph has been deleted.

7. This paragraph has been deleted.

METHODOLOGY

Part I: Construction Phase SACP

8. The construction phase SACP factors in an assessment of risks related to construction and its funding under the "Project Finance Construction Methodology," Nov. 15, 2013. To mitigate some elements of construction risk, power projects may use contractual agreements to transfer some elements of construction risk to counterparties. As such, the construction phase SACP includes an assessment of any contractual terms and potential risk transfer.

9. Power projects can be classified by the type of technology and contracts. Typical contracts and commercial arrangements include the following:

- Power purchase agreements (see the Glossary in "Project Finance Framework Methodology," Sept. 16, 2014). These are offtake contracts for power projects that generally consist of an availability fee that covers fixed costs, including debt service, that is paid subject to passing minimum availability standards; and an energy fee that covers the variable costs of generating electricity, such as fuel. The power project or offtaker may take the fuel price risk, while the power project typically takes the risk of converting the fuel to electricity. Sometimes the fee is paid only for the energy delivered.
- Tolling agreements (see Glossary in "Project Finance Framework Methodology," Sept. 16,

2014). These are offtake contracts for which a counterparty pays a power project to convert a feedstock (see Glossary in "Project Finance Framework Methodology," Sept. 16, 2014) into electricity or another product, such as steam, at a defined efficiency rate. Typically, the counterparty supplies the feedstock.

- Feed-in-tariff agreements (see Glossary in "Project Finance Framework Methodology," Sept. 16, 2014). These are offtake arrangements in which a power project is able to earn a revenue stream simply by feeding its production into the electric system. The feed-in-tariff can be paid in the form of a contract (such as in Canada) or by a regulatory regime (such as in Spain).
- Cogeneration arrangements (see Glossary in "Project Finance Framework Methodology," Sept. 16, 2014). These are offtake arrangements in which a buyer purchases the electricity produced from the waste steam or heat of an industrial process.
- Merchant arrangements (see Glossary in "Project Finance Framework Methodology," Sept. 16, 2014). These offtake arrangements typically involve a power project selling its electricity output into a wholesale or bilateral electricity market without long-term contracts, making its competitive position a key credit factor. These power projects may also enter into short-term contracts, such as heat rate call options with third parties or ancillary service agreements with a local transmission system operator, to mitigate market risk.

A. Technology And Design Risk

10. Power projects span from simple technological sophistication and operational challenges, such as a solar photovoltaic panel, to very advanced technology requiring highly skilled staff to maintain performance, such as an integrated gasification combined cycle technology. Power projects also operate in very diverse operating conditions. Use of inadequate technology for the expected application or poor design could inhibit a power project's ability to meet its expected operating performance, availability and efficiency levels, or delivered operating cost profile over its life span.

11. There are many types of generation technologies used in the power sector. For a given technology, advancement in technology is typically evolutionary over time, meaning that modest improvements are continually made to a power plant's underlying design. The advancements typically focus on materials or equipment that improve efficiency and reliability or on modest scale ups. However, sometimes a technology can represent a significant leap for the power industry, such as a new wind turbine that is double the size of the previous turbine.

12. There are many different power plants design configurations. The underlying technology typically has different design features, depending on the manufacturer; and the same technology from the same manufacturer might be designed differently to accommodate local environmental conditions. A wind turbine in a very cold environment would include a heater package, while the same turbine in a warm environment would not. The overall power plant design risk is typically greater than the underlying technology design risk. Overall design risk comprise all of the elements that need to be considered for the plant to operate and deliver its electricity to the market, including the ground (or sea) and air conditions of the site, the plant building and foundations, and the fuel supply and production offtake infrastructure. The large variation of site conditions and configurations can result in a large variation in design risk for power plants.

1. Technology track record in this application

13. Under the criteria, we generally assess the following key factors for assessing the track record of a power project's technology:

- Track record over the technology's lifecycle;
- Number of power plants in operation that use the technology;
- Track record of performing under similar operating conditions to those of the project, including fuel type;
- Performance predictability;
- Lifecycle maintenance predictability;
- Manufacture track record; and
- Track record of a mix of technologies and complexity.

14. The technologies we typically assess include the following:

- Generator;
- Turbine;
- Fuel conversion system, such as a boiler; and
- Transmission systems.

15. Under the criteria, an assessment of "commercially proven" typically reflects a high level of confidence, in our view, of how the project is likely to perform over its useful life in terms of operational performance, costs, life cycle timing, and effectiveness. The factors that typically support our assessment of a high level of confidence include a long history of commercial operation; a large number of projects that have exposure to the technology under different operation conditions, including the one for the project being rated; and statistically reliable data that generally indicate very predictable performance and stable operating costs. For example, we typically assess conventional polysilicon and monosilicon solar photovoltaic panel technology as "commercial proven" because the commercial period exceeds two decades in numerous locations globally; the panel's degradation performance over a 25-year period is predicable, based on substantial and reliable commercial degradation rate data over the same length of time; and maintenance is easy, with costs well established by the industry. If a "commercially proven" technology does not have a track record in the operating conditions of the project being rated, we typically assess it as "proven" or weaker.

16. An assessment of "proven" typically reflect a satisfactory operating track record relative to the power project's scope and technology life in a similar application, but the operating period does not cover a period long enough to provide a very reliable estimate of operating performance, cost, and lifecycle profile. The factors that typically support this assessment include a meaningful number of uses of the technology in several different operating conditions, reliable data on likely future performance and costs, and a sound understanding of the power project's lifecycle. An example is a natural gas-fired turbine that has been used in a large number of power plants and has shown steady performance through at least one major lifecycle and good cost predictability. We typically classify a technology that meets the characteristics of "commercially proven" with minor modifications in this category.

17. An assessment of "proven but not in this application or arrangement" will typically apply to a technology that meets the characteristics of "proven" but has a limited number of applications in a limited number of operating conditions or one that links two proven technologies, but there is uncertainty about the effectiveness of the power projects' integration. An example is a natural gas-fired combustion turbine that meets the characteristics of "proven" but is operating for the first time on a synthetically produced form of natural gas that may have impurities that could

affect the turbine's performance or lifecycle. Another example is where a proven wind turbine designed for onshore use is used in an offshore project. Once a project has operated for a period of time and developed a track record that would support reliable long-term forecasts, we typically revise the assessment to "proven."

2. Technology performance match to contract requirements and expectations

18. Power projects may use various types of offtake contracts, such as power purchase agreements, tolling agreements, and feed-in tariffs (see paragraph 9) that have various types of performance requirements. More common contract types and typical performance requirements have minimum availability limits measured over a prescribed time period (see Glossary in "Project Finance Framework Methodology," Sept. 16, 2014). These availability levels take scheduled maintenance and expected forced outages into account.

19. We analyze a power project's technology performance relative to its availability limits based on the following:

- The technology's expected maintenance cycle and reliability performance, which may include both the fuel supply system (including boilers) and the power generation equipment; and
- The time period over which the availability is measured.

20. For merchant power projects that do not have contract requirements, we assess a project's technology match to the level of dispatch (see Glossary in "Project Finance Framework Methodology," Sept. 16, 2014) needed meet its target generation, which we establish in our base-case performance expectations (see paragraph 82 and table 7).

21. We typically assess a power project's technology performance match to contract requirements as "exceeds" when the technology exceeds all contractual requirements with a significant cushion so that full revenue would be earned even in periods of significant performance shortfalls. By significant, in this case, we generally mean that the expected performance in our base case will exceed the performance required to obtain full payment by a cushion of about 10%. For example, if a power project earns full payment under a contract when it demonstrates 80% availability and we expect it to operate at 94% availability in our base case with little variation, we will typically assess the project as "exceeds."

22. We typically assess a power project's technology performance match to contract requirements as "falls short of minor" when the contractual requirements would not be fully met under normal operating conditions, but the impact of underperformance is not likely to have a material effect on the power project's performance or cash flow. For example, we assess a coal plant as "falls short of minor" if it meets its primary availability requirement but falls short of its secondary heat rate requirement and does not suffer material cash flow loss due to underperformance.

23. We typically assess a power project's technology performance match to contract requirements as "falls short of material" when the technology choice is not consistent with the expected application or where it does not meet a key performance requirement and the impact on cash flow is material. For example, a combustion turbine peaker technology designed only to operate in peaking periods of high electricity demand would be inconsistent for a project seeking to operate during most hours of the day because the peaker technology's relatively high cost structure would typically make it uncompetitive to other plants designed to operate this way. This could include a project that operates under a tolling contract where a failure to meet its target output results in a large payment reduction for a small drop in availability. We typically assess this case as "falls short of material" under the criteria.

3. Design complexity

24. Because power plants have been built extensively around the world, their general design for many technology types is well known. However, there are some power technology applications that have a limited track record of design performance, such as offshore wind plants. Nonetheless, few power plants have the same design because each one is designed specifically to accommodate local site and permitting conditions. By local site conditions, we generally mean the ground, air, sea, and environmental conditions; plot characteristics; water supply; storage areas; and the presence of other utility infrastructure adjacent to the site. The risk allocation of design factors for power projects among projects and counterparties can vary considerably, and we assess design complexity after contract mitigation. We consider planning and permitting risk a part of the project management assessment.

25. There are several factors that typically influence the complexity of a power project design that could impact its construction and likely operational performance under the criteria. They comprise the following:

- Environmental regulations. Restrictions on the emission of environmental contaminants or other discharges that are restricted under regulation or could negatively affect the environment are key parameters that influence a power plant's design. These contaminants could include oxides of nitrogen and sulfur, carbon, mercury, dust, and others. The discharges could include the water used for cooling that is put back into a river after use.
- Ground conditions. Soil with limited ability to structurally support building or dam loads may require more complex foundation designs to maintain building or dam stability. In addition, underground structures such as tunnels or flow tubes for hydro plants may require more complex foundation designs to prevent a tunnel collapse.
- Air conditions. The output of some types of power technologies is related to ambient air temperature or pressure, which can vary considerably during the year. Weather conditions can significantly affect the performance of some projects, such as icing on wind turbine blades. Similarly, solar projects that rely on annual rains to clean solar panels may experience lower output if rainfall is less than expected.
- Sea conditions. An inadequate assessment of sea conditions can result in immense unexpected loads on exposed equipment, which can significantly reduce useful life or result in substantial underperformance or damage. Sea conditions can also introduce significant construction challenges even in benign seas.
- Water availability. Many power plants rely on water for cooling equipment and supplying steam boilers. An inadequate assessment of the water supply could result in lower production capacity or the project not operating.
- Site surveys. Inadequate surveys can create uncertainty that could limit flexibility of design and cause unexpected delays and increase construction costs. Brownfield sites (see Glossary in "Project Finance Framework Methodology," Sept. 16, 2014) are at particular risk of inadequate survey data if existing buildings prevent survey access.
- Utilities. Sites that have a large number of utility service assets such as power lines or water pipes could limit working time and increase the risk of cable strikes, which in turn could lead to delays. Brownfield sites with limited records of utilities service asset positioning are particularly exposed to this risk.
- Environmental conditions. Contamination, endangered species, and unexpected archaeological finds could delay construction and increase construction costs.

- Site access. Very confined building sites without room for on-site material storage, poor road access, or complex decanting requirements and construction phasing can limit the contractor's ability to recover from unexpected delays.
- Refurbishment works and building conversions. Sometimes a power project involves converting a plant from one technology to another, such as converting a coal-fired plant to a natural gas-fired plant. These works can create uncertainty regarding the impact on both construction time and cost, particularly when structural works are undertaken. In addition, the refurbished building's long-term performance could also be less certain than that of a new building.

26. Under the criteria, we assess the following factors to determine the design complexity assessment:

- "Proven design." The design and construction sequence does not require material modification from known designs to account for site conditions, based on solid available site condition survey information, good construction site access, and little refurbishment work. Examples include simple solar or wind power plants with simple support foundations that have been installed in numerous ground conditions globally.
- "Modified proven design." This includes an otherwise straightforward design and construction sequence that has been tailored to meet specific site conditions, such as environmental conditions, utilities, or site access. This assessment typically applies to a commonplace combustion turbine design that has been significantly adjusted to accommodate site conditions.
- "Established design modified for site conditions." This assessment typically applies to power projects where the design either has not been extensively used or requires a lot of changes to meet site conditions or permit requirements. This typically includes a large coal plant in a tight configuration with a complex fuel feedstock system that is significantly different from common designs due to plot restrictions or nearby facilities.
- "Simple first of kind." This type of power project typically employs a design that is new but simple. For example, a capacity flywheel that has not been installed in the planned configuration but is assessed to work based on its simple design premise.
- "Complex first of kind." Power projects are unlikely to receive this assessment, since most offtakers and investors would not likely be attracted to the risks involved. A project will typically receive this assessment when it employs a new design with a complex configuration.

B. Construction Risk

1. Construction difficulty

27. Power plant design usually includes a number of components, such as the design and supply of the power generation system (the physical assets through which electricity is produced); the fuel delivery and conversion system, such as a boiler; and the balance of plant, which includes other works such as buildings, concrete foundations, and operations facilities. These contracts may also cover connections to the fuel supply or energy grid, or they may be contracted to third parties not under the power project's direct control.

28. When assessing a power project's construction difficulty and counterparty linkages, we may differentiate between the civil engineering tasks and the technology supplier tasks. We may further differentiate material and nonmaterial construction and supply works (see "Project

Finance Construction And Operations Counterparty Methodology," Dec. 20, 2011).

29. Under the criteria, an assessment of "simple building task" typically applies to a power project that is built with simple construction equipment under most environmental conditions using proven technology generally comprising simple small-scale and proven modules. The power project types and construction activities that we generally expect to fall into this category are solar photovoltaic, solar thin film, fuel cells, batteries, capacity flywheels, small scale transmission lines, and simple underground cabling.

30. Some "simple building task" power projects that comprise a very large number of module components could be exposed to construction delay risks if logistics management is not performed well. This is especially true if components are being imported from other countries. If we believe that weak logistics management would increase the risk of construction delay, we typically assess the construction complexity as "moderately complex building or simple civil engineering task" instead of "simple building task." This could occur if, for example, we view the logistics management for a large solar power project that comprises millions of solar panels sourced from different manufacturing plants around the world as weak.

31. The types of power projects we typically assess as "moderately complex building or simple civil engineering task" include onshore wind turbines, skid-mounted natural gas-fired combustion turbines, large scale transmission lines, and substations. These power projects involve more sophisticated works and specialized equipment, compared with those for simple building projects, and include cranes and rigs that require skilled operators.

32. The types of power projects we typically assess as "civil or heavy engineering task" include boilers, tunnels and dams for hydropower plants, combined cycle natural gas-fired plants, drilling for geothermal plants, collecting solar tower power plants, conventional coal-fired plants, and offshore wind and subsea transmission in benign sea conditions. These types of power projects typically involve large pieces of equipment that are transported great distances and erected on site, and require specialty skills and equipment.

33. The types of power projects that we typically assess as "heavy engineering-to-industrial task" include solar collecting tower power plants that store electricity generated in a molten medium, supercritical coal fired plants, offshore wind plants in harsh sea environments, and integrated gasification combined cycle plants.

34. The types of power projects that we typically assess as "industrial task complex building task" include nuclear power plants.

C. Project Management

35. Project management is a key consideration for power projects, and it assesses the management of the risk the power project retains responsibility for. We assess project management using seven components, as defined in the "Project Finance Construction Methodology," Nov. 15, 2013. This KCF provide additional guidance for assessing only the "design approval" component, as outlined below.

36. We generally expect to assess a power project's "design approval" as "positive." Nearly all power projects are built to strict technical requirements established by the offtaker and regulatory bodies. Also, most power plant technologies typically have well-known operating profiles and procedures. So the additional credit benefit of having operators and users or offtakers approve the design to limit construction or operational problems is typically less than, say, in a typical large transportation concession project where the concessionaire's design input and approval are a fundamental part of the project.

37. A "negative" assessment is likely in situations where the scope of the design is not well defined or is unlikely to meet all local regulatory requirements, which could impede the project's ability to operate as expected.

38. In cases where a power project is designed to integrate in a complex way with another project, such as a combined cycle power plant providing steam and electricity to a refinery, the operator and user's or offtaker's approval of the design is important, given the additional performance requirements that the power project will typically have to meet, such as variations in electricity and steam supply and the quality of the steam going into the refinery process. In this situation, we assess "design approval" using the "Project Finance Construction Methodology," Nov. 15, 2013.

D. Financial Risk Adjustment

1. Construction base case

39. Most power projects use an engineering, procurement, and construction contract to mitigate most construction cost and delay risk for nearly all elements of a power project. The key risks that typically remain for the project in this sector are force majeure risk (see Glossary in "Project Finance Framework Methodology," Sept. 16, 2014), which contractors usually will not take, and the cost and delay associated with any significant change orders to the design during construction that the project and the contractors agree to. Power projects may also be exposed to delay due to variations that are agreed to during the construction process. If we conclude that force majeure is a significant risk or that change orders are likely to occur, we typically make provisions within our base-case scenario to account for such likely delays or cost increases.

40. Some power projects allocate major construction efforts to a major contractor and then less challenging works to other third parties. One arrangement is where the project employs one contractor for the electricity production system and another contractor for the balance of plant, with neither contractor providing full responsibility for the power project's completion. The electricity production contractor will typically engineer, procure, and construct the production components on foundations established by the balance of plant contractor. In these situations, our base case typically includes additional cost and delay that could result from disagreements between the two contractors on the scope, quality, and schedule of construction works.

41. Another typical construction risk allocation arrangement in the power sector is a situation where a project uses a contractor for the main electricity production components and several other local contractors for the balance of plant works. Usually, local contractors perform this balance of plant works under cost-plus agreements. This balance of plant works could include simple underground cabling to connect an array of wind turbines to a substation, erecting dock and rail facilities for a solid fuel handling system, building natural gas supply lateral to a major pipeline, or erecting the operations and maintenance building. In these situations, we use information from our previous experience with the sector and, if available, from the contractors or independent experts to determine the likely construction cost and schedule impact in our construction base case.

42. In rare circumstances where a project does not use fixed-price contracts and the construction is undertaken on a "cost plus" basis or using a schedule of rates, we will, for the purpose of our base case, use the information the project and its contractors provide and supplement it with data gathered from similar projects in the sector. We will also use, where relevant, input from an independent expert.

2. Construction downside case

43. A primary risk exposure for a project in this sector is the failure and subsequent timely replacement of the project's building contractor. We calculate the forecast costs associated with replacing the construction contractor in accordance with "Project Finance Construction And Operations Counterparty Methodology," Dec. 20, 2011. The downside case includes an allowance for the impact of a replaceable builder not already included in the counterparty replacement analysis (see paragraph 76 of the "Project Finance Construction Methodology," Nov. 15, 2013). In cases where our issuer credit rating or credit estimate on the construction contractor is equal to or higher than the construction phase SACP profile before counterparty adjustment, the construction phase SACP is not weak-linked (see Glossary in "Project Finance Framework Methodology," Sept. 16, 2014) to the construction counterparties. As a result, the available liquidity can be allocated entirely to fund the downside scenario, or we would complete a counterparty dependency assessment for the contractor.

44. Another primary risk exposure for a power project is its failure to complete tasks under its own control that are required to complete construction or even to pass critical performance tests during the construction process. Our downside analysis factors in the potential for delay in completion of tasks that are within the power project's scope.

45. Factors that could cause an increase in engineering, procurement, and construction contract prices, which the construction downside case takes into account, include the residual risks to a project after any contractual mitigants due to variation-related delays or cost increases; planning consents; ground contamination; construction works that are required to be completed in close proximity to existing assets; and delays and cost increases linked to land acquisition, where the power project retains this risk. We also assess the potential delays related to inclement weather against the provisions that have been incorporated in the construction program, such as a contingency allowance (see Glossary in "Project Finance Framework Methodology," Sept. 16, 2014). Our downside scenario could incorporate further weather-related delays if we conclude that the contingency allowance will be fully used under normal weather conditions.

46. The construction downside cost scenario includes our assessment of likely cost increases or revenue shortfall in the following allowances:

- Project operating costs. This includes project salary allowances, office availability, insurances, and additional lender-related costs (such as increased monitoring fees and higher margins).
- Operations and maintenance costs incurred during the construction period. For example, a power project will typically deploy its operations and maintenance staff to begin work when the construction is near completion to help support completion testing and prepare for initial operations after completion.
- The impact from a reduction in expected revenues when construction funding relies on revenues earned during the construction period. This impact is offset in some cases by third-party support, such as an equity commitment or a letter of credit that replaces dollar for dollar the shortfall in construction phase revenues.
- Any construction-delay risks that the power project's owner accepts. These may include, for example, the risks the power project accepts if the construction delay is not covered by liquidity available on demand (such as through a letter of credit) or revised construction schedule.
- Additional costs the power project incurs directly in relation to the risks the construction contractor is not responsible for. These could include land acquisition costs or the costs related to the buildout of a natural gas pipeline lateral to a major gas pipeline.

Part II: Operations Phase SACP

47. The operations phase SACP factors in an assessment of risks related to operational, market, and financial performance and adjustments. To mitigate some elements of operations phase risk, power projects can often use contractual agreements to transfer some elements of this risk to counterparties. As such, the operations phase SACP includes an assessment of any contractual terms and potential risk transfer.

A. Performance Risk

1. Asset class operational stability

48. For power projects, we use the following guidance to assess the asset class operations stability defined in the "Project Finance Operations Methodology," Sept. 16, 2014. Power technologies assessments generally fall in the range of '2', which represents simple processes that are easy to operate with predictable stability, to '6', which represents technologies involving complex processes that present significant operational challenges. In rare cases, assessments of '7' to '9' are possible, which reflect much higher sophistication and potential for lengthy outages.

- A '2' assessment typically includes solar photovoltaic, fuel cell, batteries, capacity flywheels, very simple land-based transmission lines of limited scale with no substations, and steam turbines because of the relatively simple processes involved and the well-understood lifecycle requirements, which have contributed to a track record of stable availability rates.
- A '4' assessment typically includes boilers, onshore wind and combustion turbines, solar thermal, and geothermal due to greater sophistication of technology, which require more specialized skills and equipment to maintain performance and deal effectively with outages. Subsea transmission lines typically fall into this category.
- A '5' assessment typically includes combined-cycle gas turbines, offshore wind, hydro, conventional coal, and some biomass due to these power projects' additional complex electrical or mechanical engineering aspects and access challenges in some cases. Maintenance is more challenging and requires specialty equipment.
- A '6' assessment typically includes supercritical coal and more complex biomass, reflecting a higher level complex or chemical interactions and advanced skills to maintain performance and perform effective predicative maintenance.
- A '7' or '8' assessment typically includes integrated gasification combined cycle plants due to a higher level of mechanical or electrical sophistication and interactions that can result in a greater uncertainty about how outages could occur and how long they will last. Existing nuclear power plants will typically be included in this category.
- A '9' assessment typically includes relatively new nuclear power plants, reflecting the high level of complexity with dangerous materials and potential for long outages along with designs that may be relatively new.

49. Our assessment of the asset class operational stability uses a weak-link approach when more than one technology is involved. For example, a power project that comprises a peaking power plant that is assessed as '4' and a combined cycle plant that is assessed as '5' is typically assessed as '5' under this KCF.

2. Performance standards

50. A power project that generates revenues through contracts can face risk if it does not meet the minimum performance requirements specified in the various contracts. Penalties for underperformance are also an important risk consideration. They can vary from a linear reduction in revenue for underperformance to outright contract termination. We perform this assessment based on the power project's specific contract terms. We summarize the typical types of contract revenue streams and related performance requirements for power projects in table 3.

Table 3

Typical Power Project Contract Revenue Streams And Performance Requirements

	Typical main revenue stream	Typical key performance requirements/measures
Regulation		
Contracted price	Subject to formula in contract	Various
Utility - rare	Volume-based pricing to achieve regulated return on equity	Service performance
		Demand forecasts
		Cost of service
Feed-in-tariff (sometimes in form of a contract)	Fixed-price tariff for all energy delivered, possibly with escalators; no volume guarantee	Minimum level of electricity production over a period
Capacity markets	Capacity payment, usually based on market auctions and fixed for a short number of years	Tested capacity annually
		Availability
Tax credits/grants	Fixed tax credit per unit of production	Level of production
	Fixed grant tied to capital cost	Grant typically tied to completion of construction and startup of plant
Contracts		
Power purchase agreement/concession	Capacity payment subject to availability	Availability
	Energy payment covering variable operating costs	Conversion efficiency (such as heat rate)
	Payments for other services as contracted	A minimum level of electricity production (such as geothermal, solar, and wind)
	All types may have escalators	
Tolling agreement	Fixed price capacity payment subject to availability that may have escalator	Availability
	Variable operation and maintenance start or stop fees, and heat rate adjustment for dispatch variation	Conversion efficiency (heat rate)
Merchant	Price of power sold into wholesale markets or short-term bilateral agreements	Availability
	Heat rate call options	Conversion efficiency (heat rate)
	Price of renewable energy credits	Cost competitiveness

Table 3

Typical Power Project Contract Revenue Streams And Performance Requirements (cont.)

	Typical main revenue stream	Typical key performance requirements/measures
		Penalties for failing to provide bid energy or capacity
		Cycling profile of plant: base load nuclear, base load fossil fuel, and peaking

3. Resource and raw material

51. Power projects secure access to resource and raw material feedstocks in different ways. Many power projects tap directly into resource and raw material reserves, such as run-of-river hydro, wind, solar, and geothermal. A coal power plant that relies on its own coal mine for all feedstocks is another example. Our resource and raw material assessment for these types of projects focuses on the characterization of the natural resource to determine if the resource or raw material will be available in the quantity and quality needed to meet production and performance expectations.

52. Some power projects such as combined cycle gas turbine plant and coal plants will typically contract for feedstocks with third parties. In these cases, our analysis focuses on contract terms and counterparty creditworthiness. Sometimes, these projects might obtain part or all feedstocks on spot markets or under very short-term contracts. In those cases, after contract mitigation, we focus on the power project's ability to secure from the market the quantity and quality of resource and raw material it needs to meet production forecasts.

53. Contractual arrangements typically have two components: one contract for the supply of a feedstock and another contract for the transportation and delivery of a feedstock. Quality requirements are a major consideration of the contracts, and supply contracts vary from a few months to a power project's entire asset life. We assess fuel supply price risk under "market risk."

54. A power project might take force majeure risk in supply contracts. For example, a coal supplier would likely be excused from supplying coal under a contract if a severe winter storm interrupts its ability to mine coal and deliver it to a transportation hub. In this case, we assess the likelihood of this event and the mitigants to this risk, such as the availability of alternate suppliers or large stockpiles on site that can support expected operation for several weeks or months.

55. Transportation of natural gas feedstocks typically occurs in pipelines that have limitations on throughput. Some projects will contract for "firm" transportation rights to pipeline capacity, which insures that the power project's contract capacity is always available whenever demand for the pipeline capacity exceeds supply. Under firm contracts, the power project may be exposed to force majeure risk. In this case, we assess the potential for force majeure interruption along the pipeline and examine any mitigants to this risk, such as the availability of alternate supply chains. Some power projects will contract for "non-firm" transportation rights to pipeline capacity that give the power project access to pipeline capacity when its capacity is not being fully utilized. This could introduce risk, since the power project may not be able to obtain fuel when there is high demand on the pipeline. Under transportation contracts, a power project may take force majeure risk, so we assess the potential and mitigants for this risk as noted above.

56. An assessment of "minimal" requires essentially no risk of interruption of resource and raw material to the power project. Under contractual situations, this requires that there is essentially

no impact on the power project under likely force majeure events through the supply chain. For example, a reliable contractual coal supplier could expose the power project to lower volumes during winter months due to weather force majeure events, but a stockpile of several months of supply at the power project could mitigate this risk. We typically assess a natural gas-fired power plant that lacks a supply contract for fuel as "minimal" only if it was located in a mature natural gas market that has proven reserves well in excess of the power project's needs, with direct access to multiple natural gas pipelines. A "minimal" assessment also applies in situations in which a power project has direct access to a resource that can supply its expected requirements comfortably.

57. An assessment of "modest" matches the attributes of a "minimal" assessment except that there is a higher risk of interruption in the supply of resource or raw material to the power project due to greater risk of contract force majeure interruptions that could negatively affect production or performance, or due to an increased reliance on the availability of natural resources. We typically assess a solar resource as "modest" when we have a high level of confidence in the resource estimation, based on reliable analysis from multiyear data at the site that supports a long-term view of resource availability. We typically assess a geothermal project as "modest" in situations where the geothermal resource is well characterized by solid and reliable data on the resource's actual performance, provided that analysis indicates that the proven resource life will comfortably supply the power project's expected needs.

58. Our assessment of "moderate" typically applies when there is some uncertainty that resource and raw material will be available at all times in the quantity and quality expected. This assessment typically applies to natural resources that exhibit significant variability or that are not well characterized, in our opinion. Generally, if the resource is likely to vary from a baseline amount by 10%-20% over the long term or 20%-30% in the short term, in our view, we typically assess the resource as "moderate" and apply a '+2' adjustment to the asset class operations stability assessment. If the long-term variation is higher, generally between 20%-30% from a baseline amount, in our view, or if the short-term variation is greater, generally 30%-40%, we typically assess the resource as "moderate" and apply a '+3' adjustment to the asset class operations stability assessment. For example, if a run-of-river hydro project has limited on-site data suggesting that production could vary plus or minus 25% from a baseline amount over the long term, we typically assess this resource as "moderate" with a '+3' adjustment to the asset class operations stability assessment.

59. Sometimes a power project consists of a portfolio of several individual projects of generally similar size in which each project relies on a separate natural resource regime to generate cash flow. An example is a wind project portfolio comprising seven individual wind projects located in different parts of Australia, and each project relies on a wind regime that is independent from the wind regime supplying the other projects. By independent, we mean that variation in one wind regime is not highly correlated to the variation of another, based on analysis of historical data. In this case, we expect the overall variation in the wind project's production to be less variable than the production from any single project in the portfolio. Therefore, we typically assess the project one level better than the lowest assessment among the individual projects in the portfolio. For example, if each of the seven projects in the portfolio had a resource assessment of "moderate" with a '+2' adjustment, we typically assess the overall power project portfolio as "modest."

60. A project that relies on a solar or wind resource may have limited or no operating data. In these situations, we will conclude our assessment of resource and raw materials risk after taking into account information that can provide us with a long-term view of resource adequacy, including reliable data that is available for the project site, and, if available, an experienced independent expert's statistical assessment of the resource and the likely production of electricity from it. For projects of this type, we will assess resource and raw materials using the methodology defined in

Appendix A and table 10.

61. We generally assess transmission projects as "minimal," since they are not typically exposed to resource and raw material risk.

B. Market Risk

62. Market risk assesses the likely impact nonperformance market-related risks have on a power project's cash flow after factoring in contract terms that mitigate market risk and the project's competitive position. These risks generally include the power project's ability to sell and deliver all of its production to offtakers or into the market, the electricity price it earns for its production, the cost it pays for raw materials that influence its cost structure, and the penalty for under-delivering on a contract requirement.

63. If a power project's cash available for debt service drops by less than 5% from the base case to the market downside case, we do not assess market risk. For example, there is typically no market risk for a tolling power plant that is usually exposed only to operational availability and efficiency risk.

64. The type of market a power project is operating in influences the level of market risk. There are generally three types of power markets, and each has different levels of market risk. They are as follows:

- Regulated markets: where typically a central authority periodically establishes market prices based on anticipated demand to provide a participant with a fixed return on equity investment. In this case, we typically conclude that the project is not exposed to market risk. However, some regulated power projects may be subject to regulated tariff, which mitigates market price risk, but are still exposed to volume risk, such as a merchant transmission project that has a regulated tariff but no captive customer base.
- Administered wholesale markets: where typically a central authority manages a power market for buyers and sellers in which market price signals typically determine the volumes delivered. Cash flow in these markets can be quite volatile when market prices are driven by commodity prices, which in and of themselves can be volatile. This volatility could also affect a power project's ability to economically place all of its output into the market. Some markets, however, exhibit more stable pricing, hence much less market risk. Administered markets could also include capacity markets in which producers receive a capacity payment, based generally on available production capacity, to attract investment and maintain a certain reserve margin for the region. Revenues from a capacity market may be less variable than those from an energy market.
- Bilateral markets: where typically there often is no established deep market, and buyers and sellers contract directly with each other. However, bilateral markets may also exist within administered wholesale markets, such as when a utility that is active in wholesale markets contracts directly with a geothermal project. In addition, some governments may offer long-term contracts as a form of support to power projects in these types of markets to incentivize investment in certain technologies, particularly renewable technologies. If a power project has a contract in this type of market that covers price and volume risk, we generally conclude no or "very low" market exposure. For an uncontracted power project in a bilateral market, market exposure could be very high. For example, a project with a high cost position may not be able to secure any meaningful bilateral contract and thus earn little or no cash flow.

65. A power market may have a limited history. Therefore, when assessing market downside conditions for power projects (as noted in the "Project Finance Operations Methodology," Sept. 16,

2014), we look at unfavorably low points within the market's limited historical context and make any adjustments to historical performance to reflect current market factors. For example, if a new carbon tax is imposed that results in higher power prices, we take this carbon tax into account when assessing low historical power pricing for the downside case.

1. Market exposure

66. Market exposure risk addresses a power project's exposure to nonoperational risks and includes adverse movements in market conditions and cost of inputs to the project commensurate with very depressed market conditions (as noted in the "Project Finance Operations Methodology," Sept. 16, 2014). When we assess market exposure, we base the projected decline in cash flow available for the debt service used on our market downside case (see table 4 for more detail). We typically evaluate the risk of higher costs for variable and fixed operations, maintenance, and major maintenance as an operating stress in the downside case.

67. We generally expect that power projects with power purchase agreements, tolling agreements, and feed-in-tariff arrangements will not be exposed to market risk when there is very limited fuel price risk and very limited transmission curtailment.

68. The key market risks for power projects aside from regulation include the following:

- Power price, base or peak, depending on which market the plant must deliver into;
- Ability to sell all potential production volume into the market;
- Fuel cost;
- Transmission interruption and dispatch constraints; and
- Exposure to replacement cost for contract underperformance.

69. The price of power is typically a function of many demand and supply factors, and it is heavily influenced by the overall configuration of the market's transmission system. Power projects in most established markets are typically price takers, so they are not usually able to significantly influence market price. However, some projects in bilateral markets are able to influence market prices by their scale or location.

70. The price of power can influence the amount of production volume that a power project can economically place into the market. If the market price for a period of time is not sufficient to cover a power project's total cost of production, it is typical for a power project to not operate and thus not sell into the market during that time (though some may operate during that time to avoid the cost of shut down and restart). Since market prices typically vary during the day and over the course of a year, the amount of production that a plant will sell into the market could vary as well. Generally, the lower the cost of production, the more volume a power project can sell into the market. For example, nuclear plants generally have low costs of production in relation to other power plants in the system and thus are able to operate at full capacity and sell all possible production volume into the market economically. A combined cycle power plant usually has a much higher overall cost of production than a nuclear power plant, and it thus operates only during the day when demand for electricity is high but not at night when other lower-cost power plants can supply the lower demand. For this power plant, the price of power determines its level of operation and the revenue it earns when operational.

71. The cost profile of a power project is closely related to its fuel cost and the fuel costs of other power plants in the market. If a power project's fuel cost changes significantly, the result would likely be either an improved or worse-off cost position relative to the market. This new cost structure could significantly affect the power project's ability to sell economically into the market.

For example, if a coal plant with a cost profile that is very stable due to stable coal prices competes with a natural gas-fired plant, when the cost of natural gas is high, the coal plant would typically be the lower cost producer; but if natural gas prices were to decline to very low levels, the coal plant would then be the higher cost producer, which could result in lower capacity factors (see Glossary in "Project Finance Framework Methodology," Sept. 16, 2014) and cash flow for the coal plant.

72. When there is a linkage between price and volume, we focus on the power project's energy margin to assess market exposure. The energy margin for a period is equal to revenue net of fuel costs.

73. Fuel costs could expose a power project to revenue and cost mismatch under an offtake contract. For example, when an offtaker pays a project for production based on the price of fuel at one location, but the project is only to obtain the fuel at a different location where the price is much higher; or when an offtaker pays a project for production based on the price of one fuel, but the project uses a different fuel.

74. Natural resource power projects, such as solar and wind and run-of-river hydro, will produce electricity and sell it into the market whenever the resource is sufficient to allow production. Market prices do not affect those power projects' ability to sell all of their output into the market. We capture volume risk for these types of projects in our "resource and raw material" assessment.

75. Power projects are typically exposed to transmission interruption, or "curtailment" risk in two ways: if the transmission line used to deliver the electricity is at full capacity and, as a result, the project is not be able to deliver its production; or if the transmission line is unavailable to take the power the project produces due to a system outage. A power project could mitigate the first type of risk through a contract in which the offtaker takes all transmission risk or by obtaining firm transmission rights on the transmission system to ensure that the power project has the capacity to deliver all of its production at all times. In situations where there is no effective contractual mitigant to transmission curtailment risk, our assessment of transmission curtailment risk takes into consideration the historical level of transmission outages and any likely changes planned for the transmission system that might result in greater or fewer outages.

76. Some power projects have offtake contracts that introduce the following exposure to replacement risk: if the project does not produce an expected amount of electricity, it has to pay the offtaker for the amount not delivered at market rates. While this market risk is due to the price exposure, we account for it only in our downside case, since it is typically due to operational underperformance.

Table 4

Market Exposure: Market Downside Case Guidance For Power Projects

Market factors	
Price and volume	We generally use estimated energy margins as a starting point with the most unfavorable power price expected over the next 20 years. We then factor in a reduction in the base-case capacity factor, based on the project's total delivered cost compared to the market on a quartile basis under the downside case pricing assumptions. Since these downside assumptions are typically fixed in our market downside case, the focus is on the total cost profile, which is typically more important in the short term, rather than the marginal cost profile. Our market downside case also includes a stress for any geographic basis differential related to power or feedstock costs. As a guide and for specific power markets, we generally use the following decline in capacity factor: 5% for first-quartile delivered cost profile power projects, 10% for second-quartile power projects, 20% for third-quartile power projects, and 40% for fourth-quartile power projects. We adjust this guidance based on unusual market attributes that suggest a different amount. For example, a power plant may be in a location that virtually eliminates competition due to a transmission constraint. In this case, even if the project has a fourth-quartile cost profile, the power plant could continue to operate in a down market most of the time. We generally assume at least 50% reduction in capacity factor in bilateral market with no contract.

Table 4

Market Exposure: Market Downside Case Guidance For Power Projects (cont.)

Market factors	
	We typically use commodity prices to define our downside case for power projects on a similar basis to that in the downside case in "Key Credit Factors for Oil and Gas Project Financings," Sept. 16, 2014. However, our assumption of commodity prices could be more (or less) severe relative to historical conditions if we consider the past 20 years to have been relatively benign (or abnormally stressful).
	When taking historical prices into account, we assess variations that have been driven by outside factors, such as changes in regulation or additional tax (such as carbon tax). We then look to normalize those historical prices to forecast prices and ensure a like-for-like comparison. For example, in a power market where power prices have been stable since its development and a new carbon tax is introduced that we conclude will lead to higher market power prices since the tax will be passed on to consumers, if we use historical power prices to develop our assumption of future power prices, we adjust those historical power prices upward to reflect the impact of the new carbon tax.
	For a capacity market, we assume a capacity price generally reflecting two factors: about one-third of the capital cost required to attract investment in new power plants and the reserve margin the market administrators usually establish.
Curtailment of transmission and fuel supply	Typically a 2% increase from our base-case assumptions. We would typically assume no transmission curtailment if the project is in a well-established power market--one that is centrally administered with a proven track record of very high reliability--and the transmission system, for example, is not undergoing significant expansion.

2. Competitive position

77. We assess competitive position for power projects based generally on the following five attributes:

- Regulatory support and predictability,
- Barriers to entry,
- Delivered cost relative to peers,
- Fuel supply, and
- Transmission access.

78. We assess our "competitive position" for power projects as defined in tables 5 and 6. Note that for a factor not matching the descriptors for either "positive" or "negative" in table 5, we assess it as "neutral."

Table 5

Power Projects: Competitive Position Factors

Factor	Positive	Negative
Regulation support and predictability	Stable and transparent regulatory regime. Low probability for adverse changes to tariff regimes or contracts.	Weak regulatory regime. Significant potential for unfavorable changes to tariff regime or contracts. Significant potential for introduction of new costs that are difficult to quantify and that producers would likely bear.
	Low potential for introduction of new industry costs that cannot be fully passed through to offtakers or customers.	
Barriers to entry	Strong long-term electricity demand prospects.	Weak long-term demand prospects.

Table 5

Power Projects: Competitive Position Factors (cont.)

Factor	Positive	Negative
	High commercial barriers to entry.	Limited commercial barriers to entry, or government programs that strongly support the addition of significant capacity on uneconomic terms.
Delivery cost relative to peers	First-quartile delivery cost position and strong reliability record.	Third-quartile or worse delivered cost position, poor reliability, or capacity factor that can vary materially over market cycles.
	Capacity factor is not likely to vary significantly during market cycles	
Fuel supply	Firm fuel supply and transport that may be supplemented with fuel switching capability with no loss of performance.	Non-firm fuel supply and transport in a market lacking depth and maturity of supply and transport.
Transmission access	Low potential for curtailment risk.	Significant potential for curtailment risk.

Table 6

Power Projects: Competitive Position Assessment

Assessment	Typical characteristics
Strong	All five factors in table 5 are assessed as "positive."
Satisfactory	Three of the factors in table 5 are assessed as "positive," but none are assessed as "negative."
Fair	Applies when the assessments of "strong," "satisfactory," and "weak" (as defined in this table) are not met.
Weak	More than two factors in table 5 are "negative" and no assessments are "positive," or a "negative" assessment of any one factor that by itself severely constrains the project's ability to generate and sell power.

79. For a power project that has market risk but sells all of its output to an offtaker for a known price, we assess the competitive position as "strong" or "satisfactory" (as defined in table 6). We typically assess the market risk as "strong" when the revenue earned does not vary with the power project's capacity factor, which the offtaker usually controls, and as "satisfactory" when there is some potential for the revenue to be based on the capacity factor.

80. For a power project in a bilateral market, we assess the "competitive position" as "strong" (as defined in table 6). For this assessment, we also require that the power project's delivered cost structure is (and will) likely remain essentially the lowest in the region and that it supplies electricity to large and growing load centers.

81. For solar, wind, hydro, and geothermal projects, fuel supply is usually not a competitive factor, and we have already accounted for those power projects' fuel supply risk in our assessment of "resource and raw material." Therefore, we assess fuel supply risk as "positive" (as defined in table 5) for these types of projects.

C. Preliminary Operations Phase SACP (Including Base-Case Assumptions)

82. The minimum debt service coverage ratios (DSCRs) we use in table 15 in the "Project Finance Operations Methodology," Sept. 16, 2014, are based on the DSCRs for the power project that

result from our base-case assumptions. We develop our base-case assumptions using the guidance in table 7.

Table 7

Power Projects: Standard & Poor's Base-Case Assumptions

Item	Base case
Operational factors	
Performance (availability, conversion efficiency, etc.)	Initially, we typically consider performance that is likely to be typical for the asset class in the relevant market and then adjust by factoring in particular project attributes, the performance of the power project's peers in the relevant market, our experience, and where available, independent expert opinion. Over time, our base case also takes into account actual operating results.
Variable operations and maintenance cost	Initially, we typically consider performance that is likely to be typical for the asset class in the relevant market and then adjust by factoring in particular project attributes, the performance of the power project's peers in the relevant market, our experience, and where available, independent expert opinion. Over time, our base case also takes into account actual operating results.
Routine operations and maintenance cost	Initially, we typically consider performance that is likely to be typical for the asset class in the relevant market and then adjust by factoring in particular project attributes, the performance of the power project's peers in the relevant market, our experience, and where available, independent expert opinion. Over time, our base case also takes into account actual operating results.
Major maintenance schedule and cost	Initially, we typically consider performance that is likely to be typical for the asset class in the relevant market and then adjust by factoring in particular project attributes, the performance of the power project's peers in the relevant market, our experience, and where available, independent expert opinion. Over time, our base case also takes into account actual operating results.
Fuel supply risk	We typically develop our assumptions based on the information available on the fuel supply conditions and the curtailment history for the site, as well as our experience with other power projects in the region.
Natural resource and raw material availability	We typically base our initial assessment on the expected average availability of the resource or raw material at the power project's site when sufficient on-site data is available and adjust for long-term regional trends in resource variation that may be probable, such as those that may occur due to the region's known long-term weather cycles. For example, for a coal-fired power project that has been obtaining coal from its own coal mine in fairly consistent volume and quality for many years, our expected average availability of the coal supply typically reflects this historic performance and factor in any developments that might detract from this view. In a new run-of-river hydro project where there is long-term river flow data, our supply assessment typically reflects the average water flows during that period, absent any abnormal historical conditions for the site. If we believe there is a potential for abnormal conditions within the debt tenor, such as a drought, we factor this into our analysis. In a new solar project that has very limited on-site data and limited public information from nearby sites, we are likely to use an average solar resource assessment that is lower than what the average from the limited data might suggest. For projects that rely both on solar and wind resources that have limited or no operating data and on an independent expert's statistical resource and production forecasts, we establish the base case using the methodology defined in Appendix A.
Market factors parameters	
Key commodity and raw materials costs and basis differentials	We typically use current prices for the first two to three years and then adjust prices to what we would consider mid-cycle prices. For basis differentials, we take into account the information available characterizing the differentials and adjust for market developments that could lead to lower or higher pricing between two locations than previously observed. An example of a development that could affect a basis differential is a new pipeline being built into a constrained area.
Power prices	We typically factor our base assumptions about other market factors into our assumptions of power prices.

Table 7

Power Projects: Standard & Poor's Base-Case Assumptions (cont.)

Item	Base case
Operational factors	
Capacity prices and emissions-related taxes	Some power markets include capacity markets or taxes (such as carbon tax), with prices established by a central body or determined periodically through a process. In cases where the prices are difficult to predict, we form a view of future prices based on a combination of historical prices, high level supply and demand factors that might affect outcomes, and some understanding of the prices needed to attract new investment or to achieve a policy goal.
Transmission curtailment	We typically develop our assumptions based on the curtailment history for the site and adjust to reflect any changes to the transmission system that would likely result in lower or greater outage going forward. We would typically assume that there is no transmission curtailment if the project is in a well-established power market--one that is centrally administered with a proven track record of very high reliability--and the transmission system for example is not undergoing significant expansion.
Electricity demand	We typically develop our assumptions based on historical demand patterns for the project location and make adjustments to the historical trend to reflect current market developments. To the extent that our demand assumptions are tied to economic factors, we rely on Standard & Poor's economic assumptions.
Regulation	Electricity markets are subject to changing regulation. We typically factor into our analysis the likely impact of regulation that has been approved but not yet implemented. In situations where regulation has not yet been approved but approval is highly likely, in our view, we are likely to factor the impact of the proposed regulation into our analysis.

D. Adjusted Preliminary Operations Phase SACP

1. Downside analysis

83. Our downside case combines our market downside case (see table 4) with our operational downside assumptions and financial stresses linked to any refinancing, where relevant. We develop our downside case generally using the guidance in table 8.

Table 8

Power Projects: Standard & Poor's Downside Case Assumptions Guidance

Operational factors

Availability	Our availability assumption is based on a power project's asset class operations stability assessment after adjustments for project-specific contractual terms and risk attributes (we call this the "adjusted assessment" for the sole purpose of this availability adjustment in the downside case). We generally use a 3% decrease from our base-case assumption when the "adjusted assessment" ranges from '1' to '3'. For example, if a solar project has an "adjusted assessment" of '2' and a base-case availability of 97%, we assume a 94% availability in our downside case. We generally use a 6% decrease from our base-case assumption when the "adjusted assessment" ranges from '4' to '6', a 10%-15% decrease when the "adjusted assessment" ranges from '7' to '10', and a 15% or 25% decrease when the "adjusted assessment" is '11' or '12', respectively. We typically increase these availability decline percentages if we expect material outages to occur during the time period for which we apply our downside case analysis. For example, for a hydro plant that is undertaking a major capital upgrade that would lead to lower availability, we may use availability rate declines greater than those noted above if we performed our downside case during this time. If the power project owns several power plants that generally provide an equal share of cash flow and our assessment of performance redundancy is not "positive," we typically decrease the availability decline percentages noted above by about 50%. However, the resulting downside availability assessed under table 8 with this 50% adjustment would be no greater than the downside availability under table 8 for a more diversified project that has a 'positive' performance redundancy assessment. We make this adjustment since it is unlikely that all of the projects would suffer the same level of stress at the same time.
Operations and routine maintenance and major maintenance costs	We generally use a 10%-15% increase from our base-case expectation for a "neutral" technology performance assessment: 10% when the operations and maintenance (O&M) management assessment in the "Project Finance Operations Methodology," Sept. 16, 2014, is "positive," 15% when it is "negative" (see paragraph 32 of the "Project Finance Operations Methodology," Sept. 16, 2014), and 12% when it is otherwise. We generally use a 15%-25% increase from our base-case expectation for a "negative" technology performance assessment: 15% when the O&M management assessment is "positive," 25% when it is "negative," and 20% when it is otherwise. We generally use a 25%-40% increase from our base-case expectation for a "very negative" technology performance assessment: 25% when the O&M management assessment is "positive," 40% when it is "negative," and 32% when it is otherwise.
Resource and raw materials availability	We typically assume delivery volume and quality equal to the worst level we expect for this factor over a 20-year period. For example, for a run-of-river hydro plant that has been operating for many years and sees annual variation in water supply, our downside case typically uses a water flow assessment that is near the low point of the historical performance. And for a coal plant that relies solely on coal from its own coal mine and has a track record of consistent quality but volume disruptions periodically due to extreme weather events, our downside case reflects a level of supply curtailment due to potential weather events and also factor in any mitigant to supply disruption, such as a large on-site stockpile of coal that could supply the plant for several months. For projects that rely on solar or wind resources that have limited or no operating data and on an independent expert's statistical resource and production forecasts, we establish the base case using the methodology defined in Appendix A.
Performance degradation	Typically a 3% increase from our base case. For example, if a combustion turbine has a base-case efficiency rate of 9,000 million Btu per kilowatt hour, the downside case efficiency rate would be 9,270 million Btu per kilowatt hour (that is, 9,000 x [100% + 3%]). We generally would not assume a continually declining degradation, since most power projects will typically perform periodic maintenance to recapture efficiency losses. For solar power projects, which typically experience an annual decline in output due to panel degradation, we would typically assume that degradation is 25% greater than the annual degradation assumed in the base case. These types of projects typically do not perform periodic maintenance on the solar panels to recapture lost efficiency. For example, if the base case assumes an annual solar degradation of 0.9%, we would assume an annual degradation of 1.125% (that is, 0.9% x [100% + 25%]) in the downside case.

2. Liquidity

84. Liquidity is important for power projects, since they experience periodic outages that can involve

substantial downtime and repair costs. In addition, major maintenance costs are incurred every few years and such costs can be quite large and difficult to pay out of operating cash flow. Under this KCF, a "neutral" liquidity assessment for a power project typically includes the following:

- A six-month debt service reserve. However, if cash flow is highly seasonable, a larger debt service reserve is typically required to assess liquidity as "neutral." For example, if a wind project has equal winter and summer debt payments but earns 80% of cash flow in winter and 20% in summer, a one-year debt service reserve is typically required for a "neutral" assessment, absent other accessible liquidity that provide an effective six-month reserve.
- An operations and routine maintenance reserve or similar liquidity sized on a rolling basis to cover expected operating expenses. The amount typically relates to the technology's overall complexity, the operations and maintenance tasks, and the availability of spare parts.
- A major maintenance reserve or similar liquidity that is typically funded in advance of expected need--if the power project performs periodic major maintenance. The period of advance funding typically depends on both the amount of major maintenance expenditure in relation to the amount of cash flow after paying expenses and filling reserves and how often it occurs. If major maintenance costs are a small share of this cash flow, advance funding of generally six to 12 months or so helps to ensure that the major maintenance reserve is full when needed. If major maintenance costs are a significant share of this cash flow, then funding several years in advance would generally provide more assurance that the major maintenance reserve will be fully funded when needed. The appropriate time period depends on the expenditure amount and the cash flow up to that point. The key issue is that funding is provided comfortably in advance of need.

85. A power project may allocate major maintenance costs and performance risks to a third party under what is typically known in the power industry as a long-term service agreement (LTSA). LTSAs are project specific but may typically provide equivalent protection as the major maintenance reserve. However, an LTSA's value is subject to the skill and creditworthiness of the counterparty selected to perform the major maintenance work (see "Project Finance Construction And Operations Counterparty Methodology," Dec. 20, 2011).

3. Refinance risk

86. In U.S. markets in which merchant power plants are frequently bought and sold in a generally transparent market process, we may also assess power projects on a debt-per-kilowatt comparable valuation basis to supplement our project life coverage ratio (PLCR) analysis in paragraphs 91-93 in that criteria. For example, we may value a U.S. 500 megawatt combined cycle gas turbine plant in the well-established PJM power market at about $1,000 per kilowatt, resulting in a valuation of $500 million. If this plant had $250 million of debt, the PLCR would be 2x.

87. In markets outside the U.S., we expect to apply the "Project Finance Operations Methodology," Sept. 16, 2014 for the DSCR and PLCR analysis.

88. For the purpose of calculating post-refinancing DSCRs over the remaining asset life of a power project, we use the asset lives outlined in table 9. Note that for refinancing risk analysis we reduce these asset life spans depending on the power project's operation phase business assessment (OPBA) in paragraph 85 of the "Project Finance Operations Methodology," Sept. 16, 2014. However, we may assume a longer asset life in situations if we believe the actual wear and tear on the asset has been below industry average for such plant, or if we believe the plant has been maintained at levels well above industry norms.

89. We would take into account the asset's actual performance and, if available, input from an independent expert. For example, if a combined cycle project designed to operate at a 60% capacity factor actually operated at a 25% capacity factor for many years due to market conditions, we would likely assume an asset life longer than 25 years, provided that the asset had been properly maintained as scheduled and we assessed the future operational profile to fall within the project's design capabilities. However, if we expect the project to operate at an 85% capacity factor due to limited market supply, we would typically conclude that such a profile exceeds the plant's design parameters, and we would, therefore, typically not assume a longer asset life than recommended in table 9. On the other hand, if the actual capacity factor was lower than expected due to persistent operational problems at the project, we would not assume an asset life greater than 25 years and would instead likely assume a shorter asset life due to operational underperformance. For example, if a plant designed for a 60% capacity factor operated at a 20% capacity factor but had a history of material operational problems not typically seen for the asset class, we would typically not assume a longer asset life than recommended in table 9.

Table 9

Typical Asset Life For Power Projects

Power Project	Asset life
Combustion turbine	Up to 25 years
Combined cycle gas turbine	Up to 30 years
Wind - onshore	Up to 25 years
Wind - offshore	Up to 20 years
Solar photovoltaics and thin film	Up to 25 years
Solar tower	Up to 25 years
Coal	Up to 40 years
Geothermal	Up to 25 years; up to field life
Hydro	Up to 50 years

APPENDIX A

90. A project using a solar or wind resource to produce electricity may lack an operating track record. In this situation, we conclude our resource and raw materials risk assessment after taking into account information that provide a long-term view of resource adequacy, including reliable data available for the project site and, if available, an experienced independent expert's statistical assessment of both the resource and the likely production of electricity from it. In this case, we would typically expect the independent expert to cover not only solar and wind resource forecasts but also specific technology, operating cost, capital expenditure, and maintenance requirements.

91. Solar or wind resource forecasting is typically based on a statistical analysis of resource data relevant to the project's location and site conditions. For solar and wind projects, we typically assess resource and raw materials risk and develop our base case and downside case as defined in table 10. We typically adjust the resource and raw material assessment defined in table 10 down by at least one notch if we consider the projected cash flow to be highly dependent on resource available during very short periods of the year, unless compensated for by liquidity reserves. We typically adjust the resource and raw material assessment defined in table 10 down by at least one notch if we conclude that the independent expert have limited experience with

assessing the solar or wind resource regimes or the power project's technology.

92. The independent expert should be experienced (see "Credit FAQ: Provision of Information for Assessing Project Finance Transactions," published Dec. 16, 2013). In addition to their relationship with the project sponsors, we also focus on the independent expert's experience and expertise. The key attributes include the following:

- Independence. The independent expert is typically engaged for the debt providers' benefit rather than the project sponsors', and the expert's compensation should not be directly linked to the project's successful financing.
- Experience. The independent expert should have appropriate prior experience in the sector the project covers as well as in the country where the project is located. For example, being a mining expert covering Scandinavia may not be sufficient to assess a mining project in Africa, given the different operational, weather, and market conditions.
- Track record. An independent expert's track record may also support its experience in a particular area.

93. We typically expect an independent expert report to include the following:

- Factual presentation of the project. This summarizes what the independent expert has specifically reviewed and analyzed, and it ensures that all aspects of the project have been considered.
- Risk assessment of the project. This covers all the risks pertinent to the independent expert's area of focus that could result in cash flow disruptions. For example, if the independent expert is assessing the construction of a power plant, the report would usually include the risk that the plant may not be built on budget or on time and that it ultimately may not perform as designed. The independent expert would then typically group the risks according to their likelihood of occurrence (low to high probability) and impact (low to high impact) to ensure that the key risks (high probability and high impact) are thoroughly reviewed.
- Other sections. These include the independent expert's views and analysis of the related parties' ability and experience in similar projects as well as the sponsors' assumptions in certain key areas. For example, for public-private partnership projects, the independent expert would typically review the payment mechanism and determine the level of financial abatements that could occur. For power projects, the independent expert would typically opine on assumed availability levels over the life of the project, including any potential deterioration as the plant ages.

Table 10

Power Projects: Standard & Poor's Specific Guidance For Wind And Solar Resource Assessment And Base- And Downside-Case Assumptions

Asset type, asset composition, and the amount of on-site data included in the independent expert's analysis	Typical resource and raw materials assessment	Typical base-case assumption for power production probability of exceedance value*	Typical downside case assumption for power production probability of exceedance value§
Single solar site - significant data (see paragraphs 57-58)	1	P90	P99
Single solar site - limited data (see paragraphs 57-58)	2	P90	P99

Table 10

Power Projects: Standard & Poor's Specific Guidance For Wind And Solar Resource Assessment And Base- And Downside-Case Assumptions (cont.)

Asset type, asset composition, and the amount of on-site data included in the independent expert's analysis	Typical resource and raw materials assessment	Typical base-case assumption for power production probability of exceedance value*	Typical downside case assumption for power production probability of exceedance value§
Portfolio of several solar sites - significant data (see paragraphs 57-59)	1	P90	P99
Portfolio of several solar sites - limited data (see paragraphs 57-59)	2	P90	P99
Single wind project - significant data (see paragraphs 57-58)	2	P90	P99
Single wind project - limited data (see paragraphs 57-58)	3	P90	P99
Portfolio of several wind sites - significant data (see paragraphs 57-59)	1/2†	P90	P99
Portfolio of several wind sites - limited data (see paragraphs 57-59)	3	P90	P99

*P90--An electricity production amount that would be exceeded 90% of the time when assessed statistically on a one-year period. §P99--An electricity production amount that would be exceeded 99% of the time when assessed statistically on a one-year period. †We typically use a '1' assessment when the portfolio is highly diversified with a large number of sites that show little or no correlation of natural resource regimes. Otherwise, we use a '2' assessment.

REVISIONS AND UPDATES

This article was originally published on Sept. 16, 2014. These criteria became effective on Sept. 16, 2014.

This article follows S&P Global Ratings' Request for Comment, where we solicited public feedback to the proposed criteria (see "Request for Comment: Key Credit Factors For Power Project Financings," published Dec. 16, 2013). The comments we received contributed to the changes we included in these criteria, and they are outlined in the article "RFC Process Summary: Standard & Poor's Summarizes Request For Comment Process For New Project Finance Methodology," published Sept. 16, 2014.

Changes introduced after original publication:

- Following our periodic review completed on Sept. 14, 2016, we updated contact information and criteria references and deleted outdated sections that appeared in paragraphs 6 and 7, which were related to the initial publication of our criteria and no longer relevant.
- Following our periodic review completed on Sept. 11, 2017, we updated the contact information and criteria references.
- On Oct. 30, 2019, we republished this criteria article to make nonmaterial changes to the contact information.

RELATED CRITERIA AND RESEARCH

Related Criteria

- Key Credit Factors For Oil And Gas Project Financings, Sept. 16, 2014
- Project Finance Framework Methodology, Sept. 16, 2014
- Project Finance Operations Methodology, Sept. 16, 2014
- Project Finance Transaction Structure Methodology, Sept. 16, 2014
- Project Finance Construction Methodology, Nov. 15, 2013
- Project Finance Construction And Operations Counterparty Methodology, Dec. 20, 2011
- Principles Of Credit Ratings, Feb. 16, 2011

Related Research

- Credit FAQ: An Overview Of Standard & Poor's Criteria For Assessing Project Finance Operating Risk, Sept. 16, 2014
- Credit FAQ: An Overview of Standard & Poor's Criteria For Assessing Project Finance Construction Risk, Dec. 16, 2013
- Credit FAQ: Provision of Information for Assessing Project Finance Transactions, Dec. 16, 2013

These criteria represent the specific application of fundamental principles that define credit risk and ratings opinions. Their use is determined by issuer- or issue-specific attributes as well as Standard & Poor's Ratings Services' assessment of the credit and, if applicable, structural risks for a given issuer or issue rating. Methodology and assumptions may change from time to time as a result of market and economic conditions, issuer- or issue-specific factors, or new empirical evidence that would affect our credit judgment.

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