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Financing Renewable Energy Projects under the Economic Stimulus Bill

Several factors have encouraged soaring rates of investment in the renewable energy and energy efficiency industries in the United States in the last five years -- climate change, volatile oil and natural gas prices, the adoption by states of renewable energy portfolio requirements, the extension of federal tax incentives and a consensus of public and political support. Notwithstanding the current economic climate and bank liquidity crisis, the investment community continues to recognize the importance and growth potential of the renewable energy sector.

The American Recovery and Reinvestment Act of 2009 signed by President Obama on February 17, 2009 extends and enhances the federal tax subsidies for wind, solar, geothermal, biomass, fuel cell and marine energy projects.¹ The Act gives developers seeking financing for their projects more ways to convert the tax subsidies into cash.

We are experiencing a very active development cycle in the renewable generation sector, and an active financing market, notwithstanding the current difficulties in the credit markets.

This memorandum provides a market and tax law background to financing renewable projects in the United States, focusing in particular on federal tax incentives for solar and wind power development, and the financing structures built around those tax incentives.

Renewable Energy Context

According to a 2008 trend analysis prepared by the UN Environment Programme,² worldwide investment capital flowing into renewable energy climbed from \$100 billion in 2006 to a record \$148 billion in 2007. Total financial transactions in renewable energy, including acquisition activity, was \$205 billion. Asset finance – investment in new renewable energy

¹ For a description of the tax and appropriations provisions of the Act affecting the power industry, please view our memorandum at <http://www.troutmansanders.com/support-for-energy-in-the-stimulus-package-02-13-2009/>.

² <http://sefi.unep.org/english/globaltrends.html>

capacity – was the main driver for this surge in investment, rising 68% to reach \$84 billion in 2007, fuelled mainly by the wind sector.

Among the report's other key conclusions:

- Renewable energy markets are growing more global and enjoying easier access to capital markets;
- Capital is coming from the venture investment community, the stock markets and internal financings, signaling the sector's a shift to a more mainstream status;
- Risk and uncertainty can be reduced through diversification across technologies and geography; and
- Capital investors are now more closely aligned with industry proponents in their views of expected growth.

Renewable energy projects are driven by unique energy pricing, policy and tax considerations. Significant advances in renewable energy technology over the last 25 years have resulted in reductions in the cost of energy at productive wind and solar sites. When the pricing for wind and solar power financing includes the value of tax credits and other incentives, it compares favorably with that of natural gas, the largest source of power in the United States market.

Additionally, more than half the states, including California, New Jersey, Colorado, Nevada, and Texas, have adopted renewable energy portfolio standards (RPS) requiring utilities to use a minimum percentage of electrical power from renewable energy sources, including wind and solar power. The requirements for these programs differ by state, but the adoption of RPS standards, particularly by the larger states, has encouraged renewable power development. Many utilities have chosen to over-comply with RPS standards because renewable energy is cost-competitive with traditional sources of energy.

Many states permit utilities to use REC purchases to satisfy RPS requirements. Renewable energy credits or certificates (RECs) are commodities that reflect the environmental attributes associated with investment in renewable energy generation. RECs allow electric consumers, wholesalers and utilities to purchase "green power" on a notional basis without regard to the specific source of the generation. In a financing of renewable energy property, the RECs generated by the project can be sold by the developer to a utility or other purchaser to reduce the overall financing cost.

Congress is currently considering proposed legislation would enact a federal RPS (also called RES, or renewable energy standard), under which federally regulated utilities would be required to obtain specified percentages of their power from renewable sources. Many believe the adoption of a federal standard is inevitable, and this has created interest in renewable projects as a source of future revenue from the sale of federal energy credits.

U.S. Wind Power Market

Globally, in 2007, as in previous years, more money was invested in wind projects than any other type of renewable asset. A total of \$39 billion, up 68% over 2006, poured into the building of new wind farms and the refinancing of existing portfolios. This investment sustained the industry's rapid expansion: a massive 21GW of new wind power capacity was added in 2007, a jump of 40% on 2006. Total global installed capacity passed the 100GW mark in March 2008.

Shattering all previous records, the U.S. wind energy industry installed 5,249 megawatts in 2007, expanding the nation's total wind power generating capacity by 45% in a single calendar year and injecting an investment of over \$9 billion into the economy. Over 7,500 MW is likely to be installed in 2008. The American Wind Energy Association (AWEA) estimates that American wind farms will generate an estimated 49 billion kilowatt-hours (kWh) of wind energy in 2008, just over 1.5% of the nation's electricity supply.

The U.S. is now the world leader in wind electricity generation. While Germany still has more generating capacity installed (about 23,000 megawatts), the U.S. is producing more electricity from wind because of its much stronger winds. Growth in 2009 will depend on the effectiveness of policies that the new Administration puts in place and the duration of the credit crisis.

U.S. Solar Power Market

In 2007, there was significant growth in the U.S. commercial and residential photovoltaic (PV) markets and a new utility-scale segment for PV emerged with the fastest growth of all segments representing over 15% of the annual U.S. installed PV capacity. The first new concentrating solar power plant in 15 years was completed in Nevada with dozens more utility-scale projects in the pipeline. The expansion of the solar water heating market continued. Thousands of U.S. jobs were created and billions of dollars were invested.

The U.S. continues to lead the world in the manufacture of both next-generation thin-film technologies and the polysilicon feedstock used in most PV applications. In 2007, U.S. PV manufacturing grew by 74% and U.S. PV installations grew by 45% to 150 MW-dc (grid-tied only), both among the fastest growth rates in the world.³

Utility-scale solar electricity using concentrating technologies continued to see surging interest this year. Announced contracts grew to over 4,000 MW of new concentrating solar over the next decade in the sunny southwestern U.S., and dozens of U.S. companies are entering this growing market.

Federal Tax Credits and Depreciation Deductions

Investment in renewable energy property is eligible for federal tax credits (or a cash grant in lieu of credits) and accelerated depreciation deductions.

³ Source: Solar Energy Industries Association, U.S. Solar Industry Year in Review, http://www.seia.org/Year_in_Review_2007.pdf

Production Tax Credit. The renewable electricity production credit (PTC) is based on actual energy produced by qualifying wind, closed-loop and open-loop biomass, geothermal deposits, hydroelectric dams, and marine and hydrokinetic power facilities. The PTC is 1.5¢ per kilowatt-hour (indexed for inflation) of electricity produced by the facility over the 10-year period beginning when the facility is placed in service. For 2008 the PTC was 2.1¢ per kilowatt-hour. PTCs for electricity produced at a facility placed in service after 2004 can be used to offset alternative minimum tax (AMT) liability for the first four years of production.

The PTC is reduced on a proportionate basis for grants, tax-exempt bonds, subsidized energy financing, and other credits allowable with respect to the facility.

Investment Tax Credit. The investment tax credit or energy credit (ITC), equal to 30% of the cost of the facility, is available to the owner of a qualifying solar facility placed in service before 2017. The ITC is taken entirely in the year the project is placed in service. The ITC is available to the owner of the property (including regulated utilities), whether or not the owner is engaged in the production of electricity, and regardless of the levels of production of electricity. Thus, the ITC is available to the lessor of a project under a net lease. Moreover, as discussed below, the lessor of a project that is eligible for the ITC can elect to pass the ITC back to the lessee. In that case, the lessor would claim the depreciation deductions, and the lessee would claim the ITC.

In addition to the 30% ITC for solar, a 10% ITC is available for geothermal energy property, geothermal heat pumps, combined heat and power (CHP) systems (“co-generation facilities”), qualified microturbine plants, and small commercial wind energy property, in each case, placed in service before 2017.

For purposes of calculating depreciation deductions, the tax basis of property for which the ITC is claimed is reduced by 50% of the amount of the credit (i.e., the depreciable basis is reduced to 85% of original asset cost).

The ITC may be used to offset the alternative minimum tax.

Under the Act, ITC tax basis is not reduced by tax-exempt private activity bond financing or subsidized financing of any kind provided by the federal or any state or local government.

The ITC is subject to recapture in the event the property is disposed of or ceases to be qualifying property during the five-year period after the property is placed in service. Effectively, 20% of the ITC “vests” in each of the five years following placement in service. In the event of a recapture event, the tax basis of the property is increased for depreciation purposes by 50% of the recapture amount.

Solar. Tax legislation passed in October 2008 extended the 30% investment tax credit for eligible solar and fuel cell facilities placed in service before 2017. This legislation also allows the ITC to be used against alternative minimum tax (AMT) liability, and allows regulated utilities to claim the ITC. As discussed below, the sale-leaseback is the most common financing

structure used by solar developers to maximize the value of the ITC. This trend is likely to continue in 2009.

Wind. The Act extends the deadline to place wind farms in service to 2012 to qualify for the production tax credit, and to 2013 for geothermal, biomass and marine energy projects. As discussed below, the “partnership flip” has been the most common financing structure used by wind developers to maximize the value of the PTC. However, changes made by the Act -- in particular the option to elect the ITC – may alter this trend.

The Act gives wind, geothermal, biomass and marine energy developers the option to forego production tax credits and claim a 30% investment tax credit instead. The election is available for those components of a facility eligible for five-year MACRS tax depreciation. For wind projects the option is available only on projects placed in service during 2009 through 2012. For geothermal, biomass and marine energy projects the ITC election can be exercised for projects placed in service during 2009 through 2013. Electing the investment credit will allow wind and other facilities that used the PTC and partnership structures, to use sale-leaseback and related structures that were formerly reserved to ITC solar facilities.

Advanced Energy Projects (Manufacturing Facilities). The Act adds a separate 30% ITC under Code Section 48C for investment in “qualifying advanced energy projects.” A qualified advanced energy project is one that “re-equips, expands or establishes a manufacturing facility for the production” of any of the following:

- property designed to produce energy from wind, solar, geothermal, or “other renewable resources” (e.g. a solar panel or wind turbine manufacturing facility);
- fuel cells, microturbines, or an energy storage system for use with electric or hybrid-electric motor vehicles;
- electric grids to support the transmission of intermittent sources of renewable energy, including storage of such energy;
- property designed to capture and sequester carbon dioxide;
- property designed to refine or blend renewable fuels;
- new qualified plug-in electric drive vehicles or components specifically designed for use in such vehicles; and
- any other “advanced energy property designed to reduce greenhouse gas emissions” as determined by Treasury.

This 30 % ITC is calculated upon the tax basis of “qualified property” which is part of the eligible facility. “Qualified property” is “tangible personal property” and/or “other tangible property (not including a building or its structural components), but only if such property is used as an integral part of the facility.

Unlike the conventional 30% ITC for solar, or the elective ITC, the new ITC for investment in qualifying manufacturing projects is subject to application to, and certification by,

the Department of Treasury, and a cap of \$2.3 billion on the aggregate ITCs that may be certified. Treasury is directed to select projects on the basis of commercial viability, domestic job creation, reduction in greenhouse gas emissions, technological innovation, cost efficiency, and shortest completion time.

Taxpayers whose projects are certified have three years from the date of certification to place the relevant project in service. Not later than four years after the date of enactment of the Act, Treasury may redistribute the award of these ITCs based upon an insufficient number of qualifying certification applications or delays of certified projects due to third party litigation or opposition.

Depreciation Deductions. Equipment that uses renewable energy to generate electricity generally is 5-year property eligible for MACRS accelerated cost recovery deductions over five years using the 200-percent declining-balance method (switching to the straight line method for the first taxable year for which using the straight line method will yield a larger depreciation deduction). The Act extends the “bonus depreciation” allowance to projects placed in service in 2009 (with a further extension for certain longer-lived assets). This provision allows a deduction of 50% of project cost in the year the project is placed in service. The remaining tax basis is recovered under MACRS over the remaining five-year period. As noted above, the tax basis for computing depreciation deductions (including bonus depreciation) is reduced by 50% of the ITC.

Cash Grants In Lieu of Tax Credits

Under the Act developers have the option to forego federal tax credits and instead receive a nontaxable cash grant from the U.S. government in an amount equal to 30% of project cost. The grant program requires application to and approval by the Department of Treasury.

The cash grant option is available for projects placed in service in 2009 or 2010 or that begin construction during 2009 or 2010 and are completed by a deadline. The deadline is 2012 for wind projects, 2013 for biomass and marine energy (and probably geothermal) projects, and 2016 for solar and fuel cell projects.

The 30% grant will be calculated on the same “tax basis” that would have been used to calculate the investment tax credit. Grants on fuel cell projects are capped at \$3,000 a watt. There are no caps on wind, solar, geothermal, biomass and marine energy projects.

No grants will be paid on projects that are owned wholly or partly by federal, state or local government agencies, certain electric cooperatives or Section 501(c) tax-exempt entities.

A developer can apply for a cash grant at any time, but under the Act the Treasury is required to pay the grant 60 days after the later of the application date or the date the project is placed in service. Guidance from Treasury will elaborate on what documentation is required to demonstrate that a project has been placed in service.

The legislative history provides that the grant program “mimics” the operation of the 30% ITC. Thus, the grants will be subject to recapture for the first five years after a project is placed in service in the same manner that the ITC would be recaptured if the project is sold during that period. Similarly, the tax basis of the project will be reduced by one-half of the amount of the grant. Similarly, in a sale-leaseback, the lessor may elect to pass the grant back to the lessee.

Many more details of the grant program will need to be fleshed out in guidance from Treasury. Based on the Act and underlying Congressional reports, the grants will be paid to the same person who would have claimed an investment tax credit on the project. For example, if the project is owned by a partnership, the partnership is the entity entitled to the grant. If the project is sold and leased back, then the lessor is entitled unless it makes an election to pass the grant back to the lessee.

The legislative history suggests that the existence of a single tax-exempt ownership interest in a project (however small) will disqualify the project from the grant program. It is unclear whether this was intended and if so how the rule will apply in the case of pass-through entities like partnerships.

Instead of depending on an institutional tax equity investor (and a complicated partnership or sale-leaseback financing structure), can a developer simply forgo that capital and instead collect an amount equivalent to the ITC and otherwise finance projects through more traditional sources (e.g. debt)?

One reason why developers may not choose to “go it alone” is that cash grants are paid in lieu of tax credits, not depreciation deductions. Accordingly, a developer choosing a grant will be left with depreciation deductions that it probably cannot use efficiently. These deductions can be carried forward for up to 20 years and used when the developer has income against which to offset it. Alternatively, a developer might enter into a tax equity transaction to try to convert the depreciation into cash. Because the grant is subject to recapture if the developer sells the project within five years after it goes into service, any such transaction must be completed about the time the project is placed in service. A partnership flip or inverted lease structure must fund before the project is placed in service. Any sale-leaseback of the project -- including a sale-leaseback where the lessor chooses to leave the grant with the developer-lessee -- must be completed within three months after the project is placed in service.

Only 85% of the cost of any project on which a grant is paid can be depreciated. However, in cases where a project is leased and the parties choose to leave the grant with the lessee, the lessor can depreciate 100% of the project cost, but the lessee must report half the grant as income. The income would be reported ratably over the period the project is depreciated.

Sale-Leaseback Financing Structure

Because the 30% ITC is available to the owner of a facility, whether or not the owner produces electricity, traditional secured financing techniques, including leasing, can be used to finance qualifying projects. Under the Act, qualifying projects include (1) solar and fuel cell projects placed in service by 2016, and (2) wind, biomass, geothermal, hydroelectric and marine energy projects where an election is made to claim the ITC instead of the PTC and the project is placed in service after 2008 and by 2012 (for wind) or 2013 (for other qualifying assets).

Under a sale-leaseback structure (*see Diagram 1 attached*), a developer and operator of solar assets constructs and agrees to operate a solar facility and agrees to sell the electricity produced to a utility, or to a business or institution on whose property the solar project is built (e.g., a retail “big box” store or a school) under a long-term power purchase agreement (PPA). The PPA would require the store or the school (the “power purchaser”) to buy all of the power

produced, generally at a fixed price, thereby ensuring a stream of revenue over the term of the PPA.

The developer sells the solar property to a bank or other tax equity investor (“lessor”) which leases the property back to the developer (“lessee”) under a long-term net lease. The lease cannot run longer than 80% of the expected life and value of the project. The developer-lessee shares in the ITC and depreciation tax benefits through reduced rents. To secure its rent payment obligations, the lessee grants to the lessor a collateral assignment of the PPA and other revenues (such as funds from the sale of RECs). To qualify for the ITC, the sale-leaseback transaction must be completed within three months after the project is placed in service.

If the developer-lessee wants to continue using the project after the lease ends, then it must either negotiate an extension at then current market rent or buy the project. It can have an option to buy back the project for a fixed price negotiated in advance, but the price will be the expected value of the project -- unlike a “partnership flip” (below) where the developer gets back 95% of the project without any additional cash outlay and has to pay the market value of only a 5% interest to recover the balance of the project. From the tax equity-lessor’s perspective, the residual value of the property at the end of the lease term, combined with the rents, the ITC and the tax depreciation deductions, will generate a target after-tax yield to the lessor. The transaction can be structured to also generate a positive pre-tax yield and cash-on-cash return without regard to tax benefits.

The main advantage of a sale-leaseback is it provides 100% financing. The lessor investor pays the full market value for the project at the time it is placed in service. The downside of doing a sale-leaseback versus a partnership flip is it costs more for the developer to get the project back. After the lease ends, the developer can only continue using the project by purchasing it from the investor for fair market value. Another advantage of the sale-leaseback is that it divorces project ownership from project operations, and largely insulates the investor from operational risk.

Inverted Passthrough Lease

As noted above, the tax rules allow the ITC to be “passed through” back to the lessee in a sale-leaseback context. This provision is the basis for a structure known as the inverted passthrough lease. In an inverted passthrough lease, the developer is the lessor and the tax equity investor is the lessee. The developer-lessor leases the project to a tax equity investor. The tax equity lessee (which may be a partnership in which the developer owns a nominal interest) sells the electricity and pays most of the electricity revenue to the developer in the form of rent. The developer elects to pass through the investment tax credit to the tax equity investor-lessee. The developer-lessor retains the depreciation deductions and uses it to shelter tax on the rents. The tax equity investor claims the ITC and deductions for rent due under the lease. The rent schedule may be designed to match the depreciation deductions that the investor would have claimed had it owned the project. At the end of the lease, the developer, as owner and lessor of the project, takes back the project without any additional cash outlay.

Partnership “Flip” Structure

The partnership “flip” structure has been the predominant financing vehicle for wind and other projects eligible for the PTC. This is so mainly because the sale-leaseback structure could not be used to shift PTCs to a project owner, because the PTC is available only to the party producing the electricity. The Act’s now allows the conversion of PTCs into an ITC, and further allows the ITC to be converted into a cash grant. Investors and developers now have more flexibility in the choice of financing structures.

The partnership structure maximizes the benefit of the tax benefits by using the partnership tax rules to allocate the tax benefits to tax equity investors (*see Diagram 2 attached*). The developer and the equity investor form a partnership or LLC as a project company that owns the project. Partnerships and limited liability companies are “pass-through” entities for tax purposes (rather than separate taxable entities), so the members of the partnership are treated as the owners of the project. The construction of the project is financed by funding commitments from the developer (and/or third-party construction period debt providers). Once the project is placed in service, the tax equity contribution repays all or a portion of the construction period financing.

The partnership agreement allocates between the parties taxable income or loss and cash distributions in a manner designed to optimize the after-tax economics. Once the project is placed in service and the tax equity has funded its contribution, 99% of the tax benefits are allocated to the tax equity. The cash flow is typically allocated 99% to the investor once the developer has recovered some or all of its equity investment. Those allocations remain in place until the investor has achieved an agreed yield on its investment (generally this occurs around year 10, when all of the tax benefits have been accrued). At that point, the allocations “flip,” with the developer taking up to 95% of the cash and tax attributes. The developer then has a fair market value option to buy out the tax equity’s remaining 5% interest in the project.

Unlike the sale-leaseback structure, where the back-end residual in the project can be retained by the tax equity, the “flip” structure reserves to the developer the upside potential and downside risk in the residual. By the same token, the developer’s return on its investment is delayed and more dependent on the residual in the partnership, whereas in the sale-leaseback, the developer realizes a large up-front profit on the sale of the project to the tax equity (and that sale steps up the basis of the project in the hands of the tax equity for ITC and depreciation purposes).

In October 2007 the IRS issued guidance for financing of wind projects using the “partnership flip” structure. The IRS ruling (Rev. Proc. 2007-65) provides that unless the following guidelines are met, the IRS will closely scrutinize the validity of wind energy partnerships.

- The developer must maintain a minimum 1% interest in tax attributes, and the investor must maintain a 5% minimum interest in tax items after the “flip.”
- The tax equity investor must maintain a capital investment at least equal to 20%

of the sum of its fixed capital contributions plus anticipated contingent capital contributions. The initial investment can be delayed until the project is placed in service.

- At least 75% of an investor's total capital contributions must be fixed and determinable obligations that are not contingent either in amount or in certainty of payment.
- The exercise price of any purchase option held by the developer, the investor or any related party to purchase the project or any interest in the partnership must be at fair market value as determined on the date of exercise of the option. Developer purchase options are not permitted during the first five years.
- The partnership may not have a right to require any party to buy the project, and the investor may not have a right to require any party to buy its partnership interest.
- Neither the developer nor a related party may loan any funds to the investor to invest in the partnership, or may guarantee any debt connected to that investment.
- There can be no guarantee to the investor of any amount of or allocation of the PTC, except the investor may obtain a third-party guarantee of wind resource availability.
- The tax benefits must be allocated the same way gross income from sale of electricity is allocated.

The IRS ruling by its terms applies only to wind partnerships, but it likely will inform the structuring of “flip” structures used for solar and other renewable energy assets. While the IRS ruling generously allows an allocation of as little of 1% of the tax attributes to the developer, the investor capital maintenance requirement will restrict so-called “pay-as-you-go” structures for the timing of capital contributions. One question not answered by the ruling is whether the IRS would challenge a transaction that satisfies the ruling but fails to generate a positive pre-tax return for the investor. The ruling is silent on pre-tax profit. The ruling also does not address the use of use of leverage (non-recourse debt) in the partnership.

Choosing the Right Financing Structure

Developers (particularly wind developers) should reevaluate the partnership flip structure relative to a sale-leaseback now that the PTCs can be converted into ITCs. One question is the value of the available ITC relative to the present value of the expected PTCs. Financial modeling is required to make that determination, and the answer will vary by project. Projects with higher project cost (the cost basis on which the ITC and depreciation deductions are calculated) will make the ITC more valuable. Projects with higher project capacity (greater expected future energy production) will make PTCs more valuable. The ability to “step up” project tax basis in the case of a sale-leaseback may make that structure more attractive than the partnership. And as noted above, a sale-leaseback is likely to be more attractive than forgoing third-party tax equity investment entirely, because it allows monetization of the tax depreciation deductions.

Regulated Utilities

One class of investor for whom the partnership flip may remain attractive is a regulated utility that itself is the project offtaker (power purchaser) and that has the tax capacity to use the PTCs (or ITC) and the tax depreciation. Utilities generally prefer owning projects so they can include their capital costs in the rate base on which they earn a regulated return. They also can have tax capacity. Before last year, however, utilities could not participate in wind project partnerships in which the utility was the offtaker because of the rule that to qualify for the PTC, the power had to be sold to an “unrelated party.” Under IRS guidance issued last year, however, power is deemed sold to an unrelated party so long as the party that produces it is not related to the ultimate purchaser of the power (e.g, the retail customer). Thus, a utility that purchases a project’s output and resells it to customers can be the owner (or a partner in a partnership that is the owner) of the project without jeopardizing the PTCs.

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Troutman Sanders LLP represents U.S. equity investors, lenders, developers and utilities in a variety of asset and project finance and leasing transactions encompassing a wide range of industries and transaction structures. Our commercial, tax and energy lawyers concentrate on these transactions in New York, Atlanta and Washington D.C.

Our energy practice integrates the know-how of Troutman Sanders LLP lawyers skilled in business and law, particularly in businesses related to electricity, renewables, natural gas, oil, thermal energy and nuclear power, with lawyers having expertise in tax, energy regulation, project finance, public finance, corporate law, bankruptcy, real estate and environmental law.

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For more information about our renewable energy practice, please visit:

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Diagram 1:
Sale-Leaseback of Solar Equipment

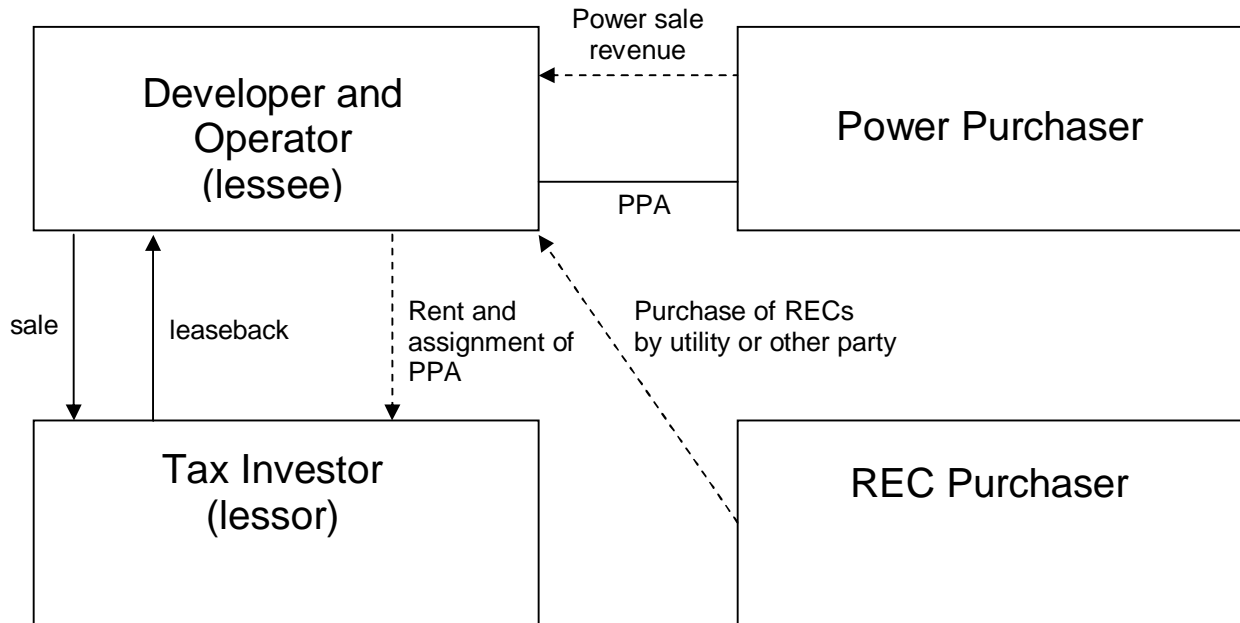


Diagram 2: Partnership Flip Structure

