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Accounting for Alternative Energy Investments

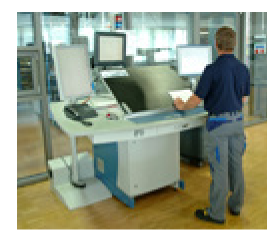
By Joseph P. Sebik

The U.S. tax code includes substantial tax incentives in the form of tax credits to promote new alternative energy projects. In December 2015 these tax credits were extended for several years. A good portion of the return on investment from these projects originates from these tax benefits, often with nominal investment risk. However, the complex financing structures and accounting for the tax credits often poses financial reporting challenges. To provide a better understanding of the complex nature of the financial reporting, here is a comprehensive look at some commonly found types of alternative energy projects and their financing and investment structures, along with the accounting for them by the investors.

The Impending Impact of Section 1071 and Creeping Consumerism on Equipment Finance

By John C. Redding, Moorari K. Shah, Kathleen C. Ryan, and Mitchell M. Grod

Section 1071 of the Dodd-Frank Act goes beyond consumer lending to regulate business credit. It broadly applies to any entity engaged in financial activity, which may include commercial lessors once the Consumer Financial Protection Bureau publishes proposed regulations scheduled for late 2016. Will you be ready?



Accounting for Alternative Energy Investments

By Joseph P. Sebik

BACKGROUND

Alternative energy has been a focus of world governments for many years now, as the fear of global warming and environmental pollution have become more and more publicized. In the United States, Congress has created substantial tax incentives to promote the construction of new alternative energy projects to bring their cost to produce energy in parity with the cost to produce energy from traditional carbon-based fuel sources. Many state governments have even created renewal energy portfolio standards to mandate the production of energy from alternative sources.

These incentives and mandates are meant to nudge the investing community to fund these types of investments. However to date, after approximately 23 years of providing various forms of these incentives starting with wind energy,[1] only about 10% of the U.S. energy supply comes from alternative energy sources.[2]

This article will examine a few of the types of commonly found projects and financing structures and will examine the accounting for the projects to provide a better understanding of the complex nature of the financial reporting. This article will also attempt to point out some of the financial reporting challenges facing potential investors. Additionally, it will address possible alternative means of accounting for those investments using internal managerial reporting workarounds.

Lastly, this article will consider whether the approach to current accounting standards can be evaluated in this time of principles-based reporting and possibly changed to better represent the objectives of the investments and incentives.

Members of the Equipment Leasing and Finance Association (ELFA) finance a wide variety of types of assets. However, only a limited number of ELFA members (and in fact investors in general) finance alternative energy investments — most often in the wind power or solar power industry. A lesser number have financed fuel cell installations, ostensibly because there tend to be less of them in general. The industry estimates there are only 20 active wind energy investors and perhaps 30 solar investors, some of which overlap wind. The point is that there are few investors.

This article will address only the accounting made by the investors in those investments, not that made by the developers of the facilities or by the entities acquiring the energy

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from the facilities — other than to perhaps touch upon them as a reason for the nature of the financing structure.

In December 2015, Congress passed and President Obama signed tax bills that extend various tax incentives for several years into the future, including many incentives related to alternative energy projects. For example, investment tax credits (ITC) for solar energy projects currently at 30% have been extended through 2019 and then gradually phased down to 10% by 2022, with the level set at 10% remaining as a permanent tax credit. Therefore, with these incentives in place and many ELFA members having the tax capacity to monetize these incentives, perhaps many members will look more closely at these opportunities, address what is holding them back, and consider investing in those types of projects.

1. TYPES OF ALTERNATIVE ENERGY INVESTMENTS

While one may think of a multitude of different types of alternative energy investments, the majority fit into two or three basic categories, varying sometimes only by the size of the facility and then by the financing structure used.

For the most part, the assets included in these investments have a certain attraction to them in that, unlike an asset with many moving parts requiring human resources to operate, most of these installations virtually operate themselves when they are placed into operation. Although they are maintained on a regular basis, there is hardly a need to actually operate them.

Whether the installation is a solar energy facility or a wind farm, they all do a few things that make them (on the surface) investable assets. They (1) generate electricity when the wind is blowing or the sun is shining as the case may be, (2) generate revenues from the sale of the power, (3) last a very long time, often 25 to 30 years or more, and (4) generate many tax incentives (which will be addressed briefly below).

Wind Energy Projects

Most of us have seen the iconic wind turbines turning in the breeze. Whether the installation is a single turbine or a farm of interconnected turbines, it usually generates electricity at a level not quite sufficient enough to be the sole source of power for a particular area. Given that the wind does not always blow and that it tends to blow more at night than during the day, the energy produced by wind is often produced at times counter to the needs of energy consumers.

Whether the installation is a solar energy facility or a wind farm, they all do a few things that make them (on the surface) investable assets.

One of the usual conditions found in most investable alternative energy arrangements is that the majority of the power produced is sold under a power purchase agreement (PPA), usually to a single off-taker (the energy buyer) for an extended time and based on a fixed rate schedule. If the energy needs to be sold into the "spot" or "merchant" energy marketplace, the investment takes on different characteristics because the price and demand will vary substantially. Most wind projects that ELFA members may look at fall into the first category: selling energy under a long-term contract with a fixed rate schedule.

Alternative energy investments are specifically targeted in various areas of the U.S. tax code with beneficial tax incentives.

Generally speaking, the larger the wind turbine is, the more efficient it is in generating energy. Before actually building a wind facility, a developer must (1) determine that sufficient wind usually blows in the area it is interested in developing; (2) determine that it can probably acquire the rights and easements to the land underneath where it would like to place the turbines; (3) ensure that it can connect the multiple turbines together and invert the energy to the current needed to be sold into the grid; and (4) be able to interconnect with the specific energy grid in question.

The suitability of the wind in a specific spot is usually determined first by historical weather surveys, and then an actual "ground" level survey is performed for some time for a more accurate reading of when and how strong the wind generally blows. The wind does not always blow, but when it does, it usually blows more at certain times of the year and certain times of the day. Unlike a power facility that consumes a fuel to produce power at will, a wind turbine produces power when Mother Nature feels like it.

Solar Energy Projects

There are more types of solar facilities than wind facilities. While an individual wind turbine may cost $2 million or more — and one of the largest planned (but not executed) wind farms was budgeted at over $2 billion — solar facilities can be as small as one that is placed on a residential rooftop and as large as a utility grade solar installation. Recently Santander Bank arranged a project costing more than $260 million in Astoria, California, where GE Energy Financial Services agreed to an equity investment commitment.

Solar energy is produced via two basic means: photovoltaic (PV) and solar thermal. Photovoltaic panels are those semiconductor panels, mounted on roofs or on the ground, which take the shining of the sun and convert it to electricity. Photovoltaic solar energy was first used industrially in France in 1954, so it has been around for some time. Solar thermal takes the heat created by the sun and focuses that on a vessel or vessels usually to generate steam to turn turbines. In that case, the sun is used as an alternative fuel to carbon-based (coal or gas), hydro, or nuclear fuel.

Solar photovoltaic projects exhibit similar characteristics to wind in that again, once the facility is operational, it runs with minimal human intervention other than to clean the panels, to repair them if they are damaged in a storm (or perhaps by children throwing stones at them), or to repair the tracking system, if one was included. Solar thermal projects are more complex because the turbines must be maintained; thus, they require a greater level of human intervention and maintenance. The majority of solar energy investments made are made in the PV market because of the lower risk associated with maintaining the facilities.

Like wind energy, solar energy is best produced at certain times of the day and certain times of the year.

Fuel Cells, Biomass, and Other Forms of Alternative Energy Projects

Fuel cells generate power by passing a fuel supply through a chemically treated "screen" that reacts to the fuel to generate electricity. A fuel cell generates hydrogen and expels water. The hydrogen gas is then used to generate electricity by creating heat to create steam and turn traditional electricity generating turbines. Biomass uses various forms of fuel such as switch grass, treated coal, waste, and so forth to burn, for the purpose of creating heat to create steam to power an electricity generating turbine.

All these technologies are great from a scientific perspective but poor from a financial investment perspective without the inclusion of a skilled and reliable operator to actually operate and maintain the facilities. For these reasons, these investments are often in a separate class of investment more akin to a true project financing, that is, an investment where the investor expects true equity level yields because of the greater risks it is assuming.

For purposes of this article, we will address the accounting only for those somewhat passive financial and or tax-oriented investments in alternative energy projects, namely solar and wind.

2. TAX INCENTIVES: CURRENT AND FUTURE STATE

Alternative energy investments are specifically targeted in various areas of the U.S. tax code with beneficial tax incentives. These tax incentives create a means by which an investor can save a substantial amount of its tax bill by making investments in alternative energy projects, thus lowering the net after-tax cost of acquiring and owning the assets.

MACRS and Bonus Depreciation

The current U.S. tax regime provides for tax incentives as a means by which the federal government encourages the investment in such projects. Although all forms of assets may be depreciated under the MACRS (modified accelerated cost recovery system) tax depreciation scheme, solar and wind alternative energy investments are afforded a depreciable life of five years. An investor can depreciate the asset over that short period and can expect energy generation for 25 to 30 years.

An investor in such a project can, in theory, earn premium-based returns.

Because of this mismatch between the long-term nature of the energy generation and the shorter depreciable life, this acceleration of depreciation is considered a tax benefit. When the facility is a revenue-producing facility, this accelerated depreciation usually creates tax losses in the early years (the five-year period), which can be used to shelter other taxable revenue.

Bonus depreciation officially terminated on December 31, 2014 (again); however, Congress (yet again) reinstated it as a tax extender retroactive to January 1, 2015, and forward to December 31, 2017, at its current levels, with a phaseout around 2020. On qualifying new assets placed in service for the first time, this allows the asset owner to claim an immediate 50% depreciation expense plus the normal MACRS percentages applied to the adjusted tax basis of the asset after the bonus depreciation.

For most taxpayers that claim a half-year, first-year convention, the total tax depreciation in the first year is then 60% of the asset cost (i.e., 50% bonus plus (20% 1st year MACRS × the 50% adjusted tax basis of the asset)). This acceleration can account for upward of a 1% financing yield benefit, depending on the tax rate and time of year placed in service. An investor in such a project can, in theory, earn premium-based returns because it can utilize the accelerated tax depreciation to shelter other taxable income and thus obtain freed up cash that it can invest in other more profitable ventures.

Production Tax Credit

The production tax credit (PTC) is available only to the producer of energy and is a tax credit that is based on the amount of energy produced (kilowatt hours). The annual rate is established by the U.S. Treasury and is indexed each year for inflation; that is, the rate changes each year and usually increases with inflation. PTC is generated for 10 years from the start of energy production of the facility. The PTC is generated by the project, so if the project — or an ownership share in the project — is sold to another investor before the 10-year period is up, the new owner may take advantage of the credits to be earned during the remaining period.

In the case of PTC, since it is based on the production of energy from the facility, there is no specific test as to whether the assets incorporated into the facility are new or used — only that the project is new and commenced commercial operations within the required time frame.

The PTC was first made available in 1992 and has both expired and then been extended several times. The PTC last expired at the end of 2014; however, again it was extended by Congress for qualifying wind energy projects retroactive to January 1, 2015, and prospectively, albeit under a phase-down schedule, through December 31, 2019.

Under recently passed tax laws pertaining to the PTC and in an effort to phase it out over time, the percentage of a particular PTC rate that a project can claim is initially set based on a "qualifying start of construction" date.

Projects started through December 31, 2016, may claim 100% of the applicable annual PTC rate during the full 10 years of their life. Projects started between January 1, 2017, and December 31, 2017, will be able to claim 80% of the then-annual PTC rate for their entire life and so on. The PTC allowable percentage rate drops through December 31, 2019, such that projects starting after December 31, 2019, will not be eligible for any PTC.

Because the PTC runs for 10 years and new PTC projects where construction commences before December 31, 2019, may not reach the project's commercial operating date for years after their start, one can expect to see PTCs coming from projects even into 2030! As we show below, these same projects may claim investment tax credits in lieu of the PTC.

Investment Tax Credit

Certain qualifying new renewable energy assets are eligible for investment tax credits. Qualifying solar energy assets have generally been available for a 30% investment tax credit of the asset cost since 2006. The 30% solar ITC was to have expired at the end of 2016, but recent tax extensions have it phasing down to 10% by 2022 and then remaining permanent thereafter. The intent of the 30% ITC has always been to bring solar energy costs into parity with the costs of traditional sources of energy. The thought was that by the time the credits phased out, the cost of alternative energy installations would reach parity with the traditional carbon-based (principally coal and natural gas) energy sources.

Qualifying wind energy assets are also eligible for a 30% ITC at the election of the project owner in lieu of the production tax credit (PTC). However, as mentioned above, since the PTC is phasing down, so, too, is the ITC election in lieu of PTC.

The choice of electing the ITC instead of the PTC for wind projects was generally based on a few factors. Since the PTC is based on the production of energy, while the probability of energy production during the 10-year qualifying period is estimated within a range, many things could happen to reduce the amount of the production: from the wind not blowing as expected to the wind turbines not producing as expected.

Generally speaking, larger, more economically efficient facilities opted for the PTC while smaller or less economically efficient facilities would opt for the ITC. Offshore wind facilities were generally more expensive to build, and thus the ITC was expected to generate a larger credit than the PTC.[3]

In an ideal situation, if the present value benefit of the PTC is greater than the ITC, one normally would elect to stay with the PTC. However, given the uncertainties of many issues in the long-term generation of wind energy, some projects may simply elect the ITC for its certainty, compared to the PTC with its variabilities.

Note that the initial tax basis of the asset is reduced by one-half of the ITC claimed. Thus, when an entity acquires $100 million of qualifying solar energy assets and claims a 30% ($30 million) ITC against that investment, the tax basis of the asset is first reduced to $85 million ($100 million – ($30 million /2)). This tax basis is then depreciated for tax purposes. This tax basis reduction then affects the accounting for the deferred taxes associated with the facility because the book basis and tax basis of the asset are different.

Because the accounting for deferred taxes generally assumes that the only difference between book and tax is a timing difference, the accounting for this basis difference within the deferred taxes becomes another nuance to the accounting for these investments. See the Accounting for the Tax Effect of the Asset Basis Reduction section below to see how this nuance affects the accounting for the investment.

1603 Treasury Grant Program

For historical reference, the 1603 Treasury Grant Program (1603 Program) enabled those entities eligible for the ITC for certain specified energy property to elect to receive a cash grant in lieu of claiming the ITC. Thus, those entities that could not use the ITC because they did not have the tax capacity to effectively utilize it could instead receive the ITC amount in cash. This enabled many poorly capitalized developers to obtain actual cash directly from the U.S. Treasury rather than structuring a complex financial arrangement with a tax investor to utilize the ITC. The 1603 Program has since expired, and it is unlikely that Congress will reinstitute it.

3. FINANCING STRUCTURES

Very often a developer of an alternative energy project does not have sufficient tax appetite to absorb all the tax credits and accelerated tax depreciation created by the projects. Whether the developer is a relatively small entity or even a major corporation, given the magnitude of the tax incentives provided by the 30% ITC as well as the PTC, that developer is often unable to use these tax benefits fully on a current (and thus efficient) basis.

Numerous financing structures and techniques are used to monetize these tax benefits, effectively enabling a taxpayer with adequate tax capacity and the tolerance for the investment to act as a somewhat passive financier/investor in the project. Although some alternative energy investments may be financed without the goal of monetizing tax benefits, the traditional ELFA investor makes such investments largely as a means of monetizing the tax benefits associated with the projects and earning a premium return on its investment. Some investments may be made by nontax-oriented investment funds; however, the principal purpose of this article is to address the accounting for those investments that are tax oriented.

Below are descriptions of the three most typical financing structures — tax-oriented lease, service contract, and tax-equity flip partnership — along with the rationale that often drives the particular form of investment.

Tax-Oriented Lease

A tax-oriented lease is a lease in which the lessor owns the asset and reports it for tax purposes. In tax parlance this is known as a "true lease for tax purposes." However, for purposes of this article, we will describe it simply as a tax-oriented lease, since a "true lease" often confuses the average reader.

Numerous financing structures and techniques are used to monetize these tax benefits, effectively enabling a taxpayer with adequate tax capacity and the tolerance for the investment to act as a somewhat passive financier/ investor in the project.

The tax elements that the tax owner reports on its tax return generally include tax depreciation, rental revenue, and the previously described tax credits. Tax depreciation would thus include MACRS tax depreciation, which is generally claimed for a large portion of solar or wind assets using a five-year MACRS life. Five-year MACRS is claimed 20% in the first year, 32% in the second, 19.2% in the third, 11.52% in the fourth and fifth, and 5.76% in the sixth year, assuming the taxpayer is following the half-year, first-year tax convention.

> Many solar projects in particular and wind projects may be constructed where the energy off-taker is a tax-exempt entity.

On December 23, 2015, Congress extended bonus depreciation, which enables a project to claim a larger first-year depreciation. Under bonus depreciation, the first year's depreciation for five-year MACRS property is 60% and the future years are adjusted accordingly. In the case of ITC qualifying assets, the lessor would also be able to claim the 30% ITC as applicable. (Again, note that the tax basis of the assets depreciated for tax purposes is adjusted downward to 85% of their cost.)

Tax-oriented leases are generally structured to meet the guidance under IRS Revenue Procedure 2001–28 and Rev. Proc. 2001–29. (An IRS Revenue Procedure is an official statement of a procedure published in the Federal Bulletin that affects either the rights or duties of taxpayers or of members of the public under the Internal Revenue Code and related statutes and regulations that is made a matter of public knowledge by the IRS.)

Although these revenue procedures address the IRS safe-harbor guidance when structuring a tax-leveraged lease, they are generally followed for most leases without nonrecourse third-party debt being involved. The key factors affecting the lease structure for solar or wind projects are that (1) the lessee cannot have an option to purchase the facility at other than fair market value; (2) the lease term cannot be greater than 80% of the economic useful life of the asset; and (3) the lessor must maintain a minimum at-risk residual value investment of at least 20% of the asset's initial fair market value cost.

Many solar projects in particular and a few wind projects may be constructed where the energy off-taker is a tax-exempt entity. Examples of tax-exempt entities that commonly seek solar or wind financing include municipalities, state or local governments, state universities, government agencies, and tax-exempt hospitals. Under special rules related to leases to such tax-exempt entities,[4] tax benefits are severely limited to the lessor.

In general, when the lease is to a tax-exempt entity, the lessor cannot claim MACRS depreciation, bonus depreciation, or any investment tax credits. This is strictly driven by the fact that the agreement is a lease for tax purposes. These rules are referred to as the Pickle depreciation rules, because the bill introducing them was made by Congressman James J. Pickle. The Pickle depreciation rules are discussed in the Tax Rules Background sections below.

Service Contract

A service contract is a financing structure wherein the project owner operates the facility and sells the output (electricity) from the facility to an off-taker. The form of the service contract agreement usually is called a power purchase agreement. Unlike a lease, the off-taker is not responsible for operating the facility or maintaining it. Those operating and maintenance obligation costs are the responsibility of the project owner.

Because a service contract is not a lease, no rents are paid; however, the off-taker may be responsible for buying 100% of the output of the facility under the PPA. Thus, whenever the facility produces energy, the energy is delivered to the off-taker, which purchases it based on a pricing schedule stipulating the rate per kilowatt hour that the off-taker will pay.

Generally, the rate schedule starts at an initial agreed-upon rate and then increases annually to reflect the anticipated increase in operating costs of the facility as well as the comparable anticipated energy costs found in the open energy marketplace. For instance, the rate may increase 2% per year for each of the years of the agreement because historical trends have demonstrated that traditional energy costs increase at about the same rate.

Given that the initial rate under the PPA provided for an initial savings to the off-taker compared to its estimated cost of directly buying power from a utility, and given that future escalations are meant to match estimated actual energy costs, the off-taker estimates an overall savings over the life of the agreement.

The form of the PPA is that of a service contract and not a lease, so when the off-taker is tax exempt, the project owner can claim all the usual tax benefits of the facility, including MACRS depreciation, bonus depreciation, and the ITC when available.

Note also that the off-taker would not be subject to lease accounting rules since the agreement is not a lease. Thus, under current accounting rules, there is generally little risk that the assets would be capitalized on the off-taker's balance sheet. In essence, the off-taker is buying power in a manner consistent with buying power from its local utility. Such purchase agreements are not considered debt obligations that are capitalized on the off-taker's balance sheet.

Tax-Equity Flip Partnership

A tax-equity flip partnership takes the service contract arrangement a step further by having the facility itself owned by a partnership. This structure first came about in the wind energy area, wherein the production tax credit was provided only to the producer of the energy. Since developers did not have the tax capacity to utilize the tax benefits, they formed partnerships with "tax-equity" investors that could use the tax benefits. In that case the partnership became the provider of the energy.

Under the Internal Revenue Code (IRC), a partnership is a "pass-through" entity wherein the partnership itself is not taxed on its earnings, but the taxable earnings or losses as well as any tax credits are passed through to the individual partners. Normally these tax elements are passed through based on the ownership percentages of each partner.

Partnership taxation is addressed under Section 704 of the Internal Revenue Code, Partner's Distributive Share. IRC Section 704(a), Effect of Partnership Agreement, states that "a partner's distributive share of income, gain, loss, deduction, or credit shall, except as otherwise provided in this chapter, be determined by the partnership agreement."

IRC Section 704(b), Determination of Distributive Share, states,

> A partner's distributive share of income, gain, loss, deduction, or credit (or item thereof) shall be determined in accordance with the partner's interest in the partnership (determined by taking into account all facts and circumstances), if
>
> - the partnership agreement does not provide as to the partner's distributive share of income, gain, loss, deduction, or credit (or item thereof), or
> - the allocation to a partner under the agreement of income gain, loss, deduction, or credit (or item thereof) does not have substantial economic effect.

Thus, under these rules, within the partnership agreement the partners may, subject to meeting the substantial economic effect test, allocate the free cash, taxable income, and tax credits from the partnership in a manner that is disproportionate to their ownership. In this manner a partner such as the developer, which may have no capacity to utilize the tax benefits, is allocated a nominal amount of the initial free cash and tax benefits. The other partners, typically called the tax-equity partners, are allocated a majority of the initial cash and tax benefits as repayment of and return on their investment until they reach a targeted after-tax internal rate of return (AT-IRR). The current market range AT-IRR for tax-equity flip partnership financial investors (not the sponsor or developer) is between 7% and 8% and has been in this range for several years.

Under these arrangements, the traditional ownership percentages of the partnership do not bear the same characteristics as those found in a traditional partnership. That is, the so-called ownership percentages are ignored and replaced by operating stipulations in the partnership agreement. Normally a partner's book ownership percentage is based on its contribution in relation to the other partners, and it is increased (or decreased) by income (or losses) allocated to the partner and decreased by withdrawals from the partnership.

From a tax perspective, the same is true with regard to the individual partner's tax basis in the partnership, except that the income or losses allocated are the taxable income or losses. In this manner, the partner's individual investment in the partnership will have both a book basis and a tax basis. The tax basis within the partnership is typically called the tax capital account.

The developer is mandated by the partnership agreement to act as the managing partner in the partnership. The tax-equity investors, which are somewhat passive investors simply seeking a somewhat guaranteed financial return largely from the tax benefits, mostly wait to receive their tax allocations and cash distributions.

If these financing structures followed the traditional partnership structure, the tax-equity investor potentially would start with a majority ownership percentage once it bought into the partnership. However, that percentage would change dynamically over the life of the investment as the tax-equity partner is being allocated more cash than the developer.

> Since developers did not have the tax capacity to utilize the tax-benefits, they formed partnerships with "tax-equity" investors that could use the tax benefits.

Further, the allocation percentages of free cash and tax benefits change at certain times during the life of the partnership — in essence, the amounts being allocated "flip" between the tax-equity investors and the developer when certain time based points are reached. Typically, the partnership agreement calls for the allocations of cash and tax elements to flip when it is anticipated that the tax-equity investor has achieved a targeted AT-IRR.

The time frame for achieving the targeted AT-IRR is fairly well forecasted, because a significant portion of the tax-equity investor's yield comes from the allocation of tax benefits and the projects typically provide a reasonably predictable amount of energy that is sold to an off-taker at a predetermined rate.

These tax-equity flip partnership financing structures typically start with a developer building the project and arranging for tax-equity commitments to be funded at a future period: when the project is just about ready to reach commercial operation date, or COD. The tax-equity investors' contributions into the partnership are often used to pay down the construction debt and often allow the developer to recoup some of its initial investments along with some initial construction profit — namely, the difference between the fair market value of the project and the developer's cost to construct it.

For instance, on a project with a $100 million fair market value, the developer's cost may have been only $85 million to $90 million. During this initial period, the tax-equity investor may allow a predetermined amount of free cash to flow to the developer, even as much as 100% up to a stated amount, but generally the allocation percentages quickly flip to where 100% of the free cash and tax benefits are allocated to the tax-equity investor. All these allocations are specified in the partnership agreement, and external tax counsel generally opines on the acceptability of the allocations in accordance with IRS Rev. Proc. 2007–65.

Table 1 shows a basic example of a tax-equity flip structure that complies with the safe-harbor allocations specified within Rev. Proc. 2007–65 with respect to the allocation of partnership cash distributions, taxable income or losses, and the tax credits. The phase descriptions below are not specified in the tax code but have been included simply as a means of describing the periods.

Table 1. IRS Revenue Procedure 2007–65 Percentages of Permitted Allocations of Tax Elements

		Developer		Tax-equity investors	
Phase	**Phase description**	**Free cash %**	**Tax benefits**	**Free cash %**	**Tax benefits %**
1	Developer partial repayment period	100%	1%	0%	99%
2	Tax-equity partner targeted earning period	0%	1%	100%	99%
3	Post-flip period	95%	95%	5%	5%

Source: All tables in this article were created by the author.

Phase 1

The funding contributed by the tax-equity investors often pays down some of the construction debt balance. Once the facility is placed in service, the developer may be distributed a substantial portion of initial free cash to start recouping its investment while up to 99% of tax benefits are allocated to the tax-equity investors. The cash distribution to the developer will generally be capped to ensure that the developer does not cash out its entire profit; the tax-equity investors generally want to make sure the developer stays heavily involved in the project.

Phase 2

After the developer has withdrawn the agreed-upon initial cash, the partnership agreement calls for its first "flip" where the allocations change. Generally, the partnership agreement provides that 100% of the free cash is then distributed to the tax-equity investors. The tax-equity investors continue to be allocated 99% of the tax benefits.

During this period, which is labeled "tax-equity partner targeted earning period" in Table 1, the tax-equity investor is counting its allocations toward earning the 7% to 8% AT-IRR targeted return. This targeted return is actually stipulated in the partnership agreement.

Prior to entering into any such transaction, the developer or its advisors provide very detailed financial models showing all the elements and assumptions about the facility cost, tax depreciation lives, tax credits, energy production assumptions, PPA rates, and resultant revenues, operating expenses and so forth, as well as provide a modeling of the cash and tax allocations and how the targeted return will be measured for the tax-equity partners.

Although the financial model looks very much like a detailed long-term financial plan for a true operating company, many of the elements are fairly fixed. The revenue is the major element that varies because it is based on production; however, even that is actually somewhat fixed because the wind blowing or sun shining is fairly predictable. That is, given the solar or wind studies performed and the fixed energy rates in the PPA, the parties have a reasonably good confidence level of the revenue that will be produced over time.

A good portion of the tax-deductible expenses originate from the depreciation of the facility, and the other costs are somewhat nominal and fixed because of the long-term nature of the plant and its minimal maintenance costs. Therefore, with reasonable certainty one can model the free cash flows and taxable income and losses originating from the plant during its lifetime.

Typically, the financial model will also include the cash and tax allocation schedules to demonstrate how much free cash is distributed according to the partnership agreement as well as how much of the taxable income and tax credits are allocated to the partners. The tax benefits are then converted to a "cash equivalent."

Consider a $100 million project that is entirely eligible to be depreciated using five-year MACRS. Assume that the developer invests $50 million and the tax-equity partner invests the other $50 million. During the tax-equity earning phase, the tax-equity investor would be allocated 99% of a $30 million ITC, worth $29.7 million.

Furthermore, the investor would be allocated 99% of the $17 million tax depreciation for the first-year tax depreciation ($100 million cost less (½ × $30 million ITC basis reduction) × (20% 1st year MACRS)), worth $5,890,500 using a 35% federal tax rate. Thus, the tax-equity investor would have received a cash equivalent distribution of $35,590,500 in payment of its return *on* its investment plus a return *of* its investment.

Using these benefits converted to a cash equivalent plus the actual cash distributions, the cumulative AT-IRR for the tax-equity partner is periodically measured. This cumulative AT-IRR will grow to the targeted earnings rate (at this time approximately 8%) at around the time the tax credits and benefits have been fully utilized.

In this manner, the tax-equity partners are receiving a fairly certain level of return, since the majority of their economic earnings are actually coming in the form of tax benefits allocated to them under the partnership arrangement. Moreover, in the case of ITC, the tax benefits will occur even if the facility does not generate much power.

If the transaction is a PTC transaction, the partnership is usually structured so that the tax-equity investors achieve a targeted AT-IRR around the time the PTCs expire, currently 10 years from the COD. If the transaction is an ITC transaction, the targeted AT-IRR occurs around the fifth or sixth year, after the ITC has vested for tax purposes. That is, no ITC will be recaptured if the tax-equity investor partner's investment share is held for the required five-year period under IRS rules.

Phase 3

After the specified time frame is reached — around the time the targeted AT-IRR should be achieved, usually when tax credits have largely vested fully or no longer exist (again, five years for ITC and 10 years for PTC) — the developer is commonly provided an option to buy out the tax-equity investors. The buyout option is structured to meet requisite tax law requirements, specifically as being at the greater of (1) the then-fair market value of the tax-equity partners' ownership share (which is largely based on the now low allocations of future free cash) or (2) that value that would provide the tax-equity partner the targeted AT-IRR that was originally stipulated in the partnership agreement.

Thus, if a project were not generating adequate free cash to achieve the tax-equity partner's targeted AT-IRR because it was not generating sufficient energy, the developer partner could true-up to that return in the value in what it agrees to pay when buying out the tax-equity partner. Thus the tax-equity partner is almost always receiving a guaranteed minimum AT-IRR through this structure.

Under partnership tax accounting, tax-equity partners' investment interest increases or decreases with taxable profits or losses as well as with cash contributions or withdrawals. Tax credits do not affect the tax-equity partners' tax basis. Without getting into the very complex nature of partnership tax accounting (discussed in more detail below), in general terms the tax-equity partners' tax ownership interest declines as they receive cash distributions and allocations of taxable losses until their ownership interest decreases to a nominal level.

In essence, if one assumes that the wind will blow as expected or, in the case of a solar installation, the sun will shine as expected, and the tax credits and tax depreciation will be available as expected from the U.S. Treasury, the tax-equity investor's yield and return can be analogized to a floating payment, self-liquidating loan with a largely guaranteed fixed rate of return.

The financing structure described above is actually somewhat simpler than actual flip structures entered into, largely because of some of the tax nuances that one must consider in both structuring the allocations and also accounting for the investments. Some of these tax nuances are discussed within the tax section below.

… the tax-equity investor's yield and return can be analogized to a floating payment, self-liquidating loan with a largely guaranteed fixed rate of return.

Nonetheless, given this almost certainty of a reasonably robust AT-IRR, one would assume that many potential investors with a large tax capacity (including many ELFA members) would be eager to make these tax-equity investments. Obviously, the complex nature of the structure itself may deter some from considering investing in the structures, but the complex, somewhat unusual financial reporting results may also act as an inhibitor to making an investment.

> These (leasing) tax rules inherently create some pressure on the potential structuring of alterative energy assets.

4. TAX RULES BACKGROUND

Given that these investments are structured to monetize tax benefits as a means of taking advantage of the tax incentives provided by the federal government, it is important to understand some of the basics behind the tax rules that govern these transactions.

Tax-Oriented Lease

Leases that are structured such that the lessor claims the tax benefits associated with the ownership of the asset are generally also structured to be compliant with Rev. Proc. 2001–28/29. These revenue procedures established safe-harbor general guidelines that would allow a lessor to conclude that the lease would be respected as a *tax-leveraged lease* by the IRS.

Notice that these revenue procedures pertain only to tax-leveraged leases, not single-investor leases. At the inception of a tax-leveraged lease, the lease is financed substantially by third-party nonrecourse debt. These revenue procedures have been adopted as a leasing industry safe harbor when applied also to single-investor leases — leases where the investment by the lessor is made without the benefit of nonrecourse, external debt funding. In other words, many leasing companies generally follow Rev. Proc. 2001–28/29 when structuring leases.

If a lease fails any of the tests outlined below, the IRS may recharacterize the lease as a loan for tax purposes. Such action negatively affects the economics of the lease to the lessor because it eliminates the accelerated tax depreciation as well as ITC.

The Rev. Proc. 2001–28/29 safe-harbor guidelines can be summarized as follows:

1. The lease term should be not more than 80% of the economic useful life of the asset being leased.
2. There should be a minimum 20% economic useful life of the asset remaining at the end of the lease.
3. The lessor should have an initial and ongoing minimum 20% at-risk residual value investment in the asset during the lease term.
4. The lessee cannot have any option to purchase or acquire the asset at any time for less than the asset's fair market value.
5. The asset shall not be of limited use wherein it can be used only by the initial lessee.
6. The lessee may not make any loans to the lessor to acquire the asset.

An additional rule residing within Rev. Proc. 2001–28/29 does not specifically affect the characterization of the transaction as a tax lease: it states that the rents should be within 90% and 110% of the average annualized rent; otherwise, the IRS may reallocate the taxable income over the lease term.

These (leasing) tax rules inherently create some pressure on the potential structuring of alternative energy assets.

Specifically, in order for a lease to be treated as a tax lease — enabling the lessor to claim the tax benefits and thus pass some of those benefits back to the lessee in the form of reduced rents (compared to payments under a loan) — the lease cannot provide for a purchase option at other than fair market value.

Because a lessor will inevitably price a lease using a conservative residual value, lessors have often found that the difference between the fair market value purchase option and the pricing residual value makes these transactions difficult to execute.

Generally, an appraisal used to arrive at the projected fair market value of a solar or wind facility is largely based on what appraisers call the "income approach." Under the income approach, the value is determined based on the discounted future revenues that the facility can generate, largely based on the remaining term of a PPA or a continuation of revenues following a pattern similar to the PPA. That is, the projected future revenues continue to increase annually, similar to the way the PPA was structured. Thus, the discounted revenues are of an increasing periodic revenue value.

On the other hand, when pricing the lease, the pricing models often assume a conservative future pricing residual value because they assume the worst-case basis, namely that the facility is returned. That is, if the facility is returned at any time during the lease, it may have to be disassembled and sold for parts.

Because the construction labor contracting costs constitute a good portion of the cost of constructing an alternative energy facility, the hard asset value of a returned facility as miscellaneous returned parts is often much lower than the projected fair value of the facility in place, producing revenues.

When a lessee examines its implicit financing rate — assuming it executes a purchase option at that higher fair market value — the financing rate that is calculated to include the execution of the purchase option is often higher than the rate at which the lessee could otherwise borrow.

Additional tax challenges affect leasing to a tax-exempt entity. Under the tax code, for tax purposes a lessor is required to depreciate the asset based on the use of that asset in the hands of the lessee. The fundamental basis of this restriction is the belief of Congress that a lessor should not be able to claim tax benefits that the ultimate lessee otherwise would not have been able to claim. For instance, if a lessor leases an asset to a tax-exempt entity, the lessor generally (except under certain exceptions provided by the law) must utilize the aforementioned Pickle tax depreciation.

Under Pickle depreciation, the lessor does not depreciate the asset using standard MACRS depreciation lives and percentages but instead must use a straight-line depreciation method over the longer of (1) the alternative depreciation system (ADS) life of the asset or (2) 125% of the lease term. Given that accelerated tax depreciation is one of the fundamental tax benefits available under tax leasing, implementing Pickle depreciation restrictions acts as an economic deterrent to a tax lease by increasing the lease rate to the lessee.

Further, in order for the lessor to be able to claim both the ITC and bonus depreciation if available, the asset must be eligible to be depreciated under MACRS. Thus, leasing to a tax-exempt entity removes not just the MACRS depreciation but also any ITC and bonus depreciation that may have been available.

Combined with the restrictions of leasing to tax-exempt entities as discussed above, one finds that tax leases of alternative energy facilities tend to be provided to either (1) a commercial entity that accepts an unstated fair market value purchase option that may be determined at the future time period or (2) the developers themselves, because they have few other options for financing the facility.

In the case of the leasing to a developer, the developers often rely on some of the initial profit they earned constructing the facility along with the revenues from the PPA to pay the lease. In those cases, the developers are earning some up-front profit, are earning a spread between the overall PPA revenues and the lease, and are less concerned with final ownership of the asset after the lease is completed.

For these various reasons, many transactions associated with alternative energy assets are structured as service contracts, which are discussed in the next section.

Service Contracts

Generally speaking, under IRC Section 7701(e), a power purchase agreement involving the sale of electrical or thermal energy produced at an alternative energy facility is considered to be a service contract for tax purposes. In this case, a service contract is an arrangement in which product output (electricity or thermal power) is provided to a service recipient. Remember that in the case of a recipient purchasing this output, the recipient is usually referred to as the off-taker.

Unlike a lease where an entity pays for its use of the property, under a service contract, the off-taker purchases the output, and the amount it pays is most often directly correlated to the amount of output it purchases. Thus, if no output is provided, generally no payments are due for the services.

In contrast, under a lease agreement, payment of the lease payments is required in all events, even come hell or high water — a phrase often included in the lease documentation to mean that the lessee must make payment regardless of what has happened to the asset or circumstances surrounding the asset. There are some exceptions and nuances allowable within the tax code with respect to service-contract payments; however, for purposes of this article they do not have to be considered.

When entities such as government units, military installations, and other tax-exempt organizations (such as schools and universities) are involved in an alternative energy project as a power purchaser, satisfaction of the service contract tax rules under Section 7701(e) of the IRC may be necessary to preserve the tax benefits and incentives available to the project owner. The service contract rules serve as a set of general rules applicable to *all* types of assets that may be involved in providing services.

As discussed above, the overall benefit of arranging a transaction as a service contract in compliance with the service contract rules under IRC Sec. 7701(e) is that the owner of the asset (and thus the service provider) may claim the full tax benefits available to it without regard to the tax status of the off-taker. Thus, an owner of a solar facility can sell the electricity produced to a tax-exempt entity and can also claim MACRS depreciation, bonus depreciation, and ITC if available.

For these various reasons, many transactions associated with alternative energy assets are structured as service contracts.

These general service contract tax rules pertain to all types of service contracts and assets. The general rules for qualifying a contract as a service contract are the following:

1. The service recipient/off-taker should not have physical possession of the property.
2. The service recipient/off-taker should not have control over the property.

3. The service recipient/off-taker should not have a significant economic or possessory interest in the property.
4. The service provider should bear the risk of substantially diminished receipts or substantially increased expenditures if there is nonperformance under the contract.
5. The service provider should be able to use the property concurrently to provide significant services to entities unrelated to the service recipient.
6. The total contract price should substantially exceed the rental value of the property for the contract period.

> The service contract rules open the door to providing alternative energy facilities to a wide range of other entities by providing tax incentives when dealing with tax-exempt entities.

The tax code, however, has additional special rules related to specified assets, including but not limited to cogeneration, alternative energy facilities, and water treatment facilities. These assets are a specific class of assets that receive this more favorable, and arguably lenient, tax treatment, most likely because they provide, in the eyes of the lawmakers, this more favored type of service to the public.

IRC Sec. 7701(e)(3) establishes a special rule for service contracts relating to the aforementioned types of assets. This special rule characterizes a contract as a service contract unless it violates one of the specified prohibitions.

Under this special rule, a contract relating to one of the qualifying types of facilities will be treated as a service contract and not as a lease (regardless of satisfaction of the general rule) unless:

1. The service recipient/off-taker (or a related entity) operates the facility.
2. The service recipient/off-taker (or a related entity) bears any significant financial burden if there is nonperformance under the contract.
3. The service recipient/off-taker (or a related entity) receives any significant financial benefit from reduced operating costs.
4. The service recipient/off-taker can purchase the facility for a fixed price (other than for fair market value).

As the reader can see, the service contract rules related to alternative energy assets are somewhat easier to meet than those related to non-alternative energy types of assets. Thus the service contract rules open the door to providing alternative energy facilities to a wide range of other entities by providing tax incentives when dealing with tax-exempt entities.

Tax-Equity Flip Partnership Structure

The tax-equity flip partnership financing structure has been outlined in the Financing Structures section above. Although that section dealt with the means by which a tax-equity investor's investment and economic income is earned, it did not address the tax laws and regulation that affect the structuring of the transactions. The tax rules pertaining to the tax-equity flip partnership structures are generally covered within the rules associated with the taxation of partners' distributive share of income or loss as well as the aforementioned Rev. Proc. 2007–65.

Partnership taxation is covered under Sec. 704 of the IRC. It stipulates how taxable income or losses will normally be allocated among partners according to their ownership percentages, absent a specific agreement outlining a different acceptable allocation agreement. A partnership is not an individually taxable legal entity; rather, it is a pass-through entity, meaning that the taxable income or losses pass through to the individual partners owning interests in the partnership.

In general, absent a specific allocation agreement, the initial capital contributions (upon the formation of a partnership or when a new partner buys into the partnership) define how the initial taxable income or losses will be allocated to the partners.

A partner's ownership basis is increased by taxable income and assets contributed to the partnership over time. Conversely, the partner's ownership basis is decreased by taxable losses and withdrawals from the partnership. Normally, the taxable income or losses are not fungible the way cash or other assets are but, as stated above, are allocated based on either the IRC's normal allocation approach or a specific allocation agreement between the partners. The allocation agreement must be supported by the economic substance of the ownership interests.

Tax credits do not affect the partner basis in the partnership. Rather, tax credits merely pass through to the individual partners.

Also under the tax code, a partner cannot deduct taxable losses beyond the extent of its recourse investment. For instance, say two partners (A and B) invest $50,000 each into a partnership and agree to allocate income and losses 90% to partner A and 10% to partner B. In their first year of business, the partnership loses $100,000, and 90% of that is normally allocated to partner A. However, since partner A's recourse basis only started at $50,000, it can deduct taxable losses only up to this starting tax basis. The question then becomes, What happens to the remaining $40,000 of taxable losses?

Under the tax code, with respect to the partnership's distributive share of taxable income or losses, there are two additional concepts dealing with the above-described $40,000 loss. Incorporated into the partnership financial model, these concepts are known as a qualified income offset (QIO)[5] and a deficit restoration obligation (DRO).[6]

These rules are very complicated and best explained by a tax attorney. However in basic terms, if one partner's capital account becomes negative while the other partner's capital account remains positive, the tax code calls for a reallocation of taxable income.

The QIO is a provision in the partnership agreement requiring that the partner with the negative capital be allocated a pro rata portion of each item of partnership income in an amount and manner sufficient to eliminate the deficit as quickly as possible. That is, if a partner's capital account unexpectedly becomes negative, taxable income would be allocated to that partner through the implementation of the QIO to eliminate the negative capital balance.

This unexpected reallocation obviously affects the economics of the partner's investment. For instance, if a partner is investing to obtain a defined return on its investment and allocated tax losses are not usable, the investment must then be held for a longer period, and then additional other elements such as cash would need to be distributed to that partner in order to achieve its targeted ROI.

If the business plan that outlines the anticipated taxable income and losses seems to indicate that a partner's capital account is likely to become negative for an extended period and a QIO would not be sufficient to remain in compliance with the tax code — for instance, in the case of bonus depreciation wherein a large tax loss is created early in the life of a project — that partner can enter into a DRO to preserve the amount of tax loss allocated to it.

A DRO is an agreement that a partner has with the partnership such that in the event of a liquidation of the partnership, the partner agrees to make up the deficit in its capital account by contributing assets (cash) back to the partnership until its capital account is no longer negative.

This DRO contribution inherently then is allocated to the other partner, which has capital. It is as if one partner agrees that the other may draw additional cash at some time during the investment, as long as the drawing partner is willing to repay any excess cash drawn if the partnership needs to liquidate. Naturally, investors may be somewhat leery of entering into DROs that are very large because that would create other potential issues for them, not the least of which is their need to possibly disclose this contingent liability in their financial statements and to creditors.

In the example above, the partner may preserve the allocation of losses to the specific partner — in this case partner A — by agreeing to a DRO clause, in which case the taxable losses are allocated to partner A and not to partner B. However, partner A cannot utilize such taxable losses immediately because the losses nonetheless still exceed its capital account, which is the limit of what losses can be deducted.

These excess losses then become "suspended losses" for that partner, because they are suspended and can be used only insofar as additional taxable income is subsequently allocated to the partner from the partnership. In other words, those specific losses cannot be used to offset other taxable income of the partner.

In summary, in the example above, the first $40,000 allocated to partner A can be used to offset other taxable income that partner A has. However, the next $50,000 allocated to partner A is a suspended loss until taxable income is allocated. Obviously this is an inefficient situation.

As was discussed above, Rev. Proc. 2007–65 outlines the specific allocation structures for wind energy transactions the IRS will respect. The partners and the partnership are still subject to the other IRC rules, including the QIO and DRO, but if a wind partnership is structured following the example provided in Rev. Proc. 2007–65, the partnership should not have to seek a private letter ruling (PLR)[7] from the IRS beforehand.

Moreover, outside tax counsel would be better positioned to provide a stronger form of tax opinion, giving the partners' confidence that this complex partnership arrangement will be respected by the IRS for tax purposes.

> Revenue Procedure 2007–65 outlines the specific allocation structures for wind energy transactions the IRS will respect.

These complex tax rules are not being provided here strictly for background purposes; rather, they create a significant element that thus influences how the partner's ownership interests are accounted for. Since the wind or solar energy partnerships are designed largely to simply monetize the tax benefits provided by the U.S. Treasury, understanding the tax rules of the partnership helps one understand the steps needed for some of that accounting.

It should be noted that Rev. Proc. 2007–65 pertains to wind tax-equity partnerships. Solar partnerships may follow the same basic approach but do not have the safe-harbor qualification under Rev. Proc. 2007–65.

5. ACCOUNTING AND FINANCIAL REPORTING TREATMENT

In order to examine the financial reporting of the structures discussed above, it is important to also understand the fundamental economics that are the foundation of each of these financing structures. In each case the fundamentals of the structures will be examined and then the specific accounting approaches will be examined.

> Financial reporting may not always present the types of results that may be expected.

Although the accounting presentation of a transaction under GAAP theoretically attempts to represent the economic results as best it can, the financial reporting does not always present the types of results that may be expected, due to the complex nature of these transactions and their reliance on tax benefits.

Effect of Upcoming Lease Accounting Standards Update

In the first quarter of 2016, the Financial Accounting Standards Board (FASB) is releasing its Accounting Standards Update Topic 842, Leases. It was widely anticipated that FASB would not materially change the accounting for lessors upon release of the new standard. One aspect of the change in general will be identifying when a contract is a lease or contains a lease.

The accounting for leases by lessors will remain largely the same. If a service contract is construed to be a lease in accordance with the new tests contained in Topic 842, the owner would account for the transaction as a lease rather than as a service contract. That difference can be seen by comparing the accounting illustrations included below. However, the fundamental approaches to the specific accounting for either a lease or a service contract will remain the same, and the discussion below will continue to be applicable.

Alternative Energy Lease and Service Agreement Transactions

Fundamental Economics of Alternative Energy Lease and Service Agreement Transactions

As a recap, three basic examples of alternative energy financing structures have been examined: a tax-oriented lease, a service agreement, and a tax-equity flip partnership structure.

The investor economics of both a tax-oriented lease and a service agreement are fundamentally the same, in that the investors in such transactions earn their returns through a combination of revenues from (1) either the lease of the asset or the sale of the energy, (2) substantial tax credits, (3) tax depreciation timing benefits, and (4) the ultimate disposition of the residual value of the asset at the end of the transaction's life.

Tax depreciation timing benefits originate when a transaction creates temporary tax losses as a result of depreciating an asset over a period that is shorter than the period that the asset produces revenues. The tax depreciation benefits are further enhanced when the depreciation method provides a further acceleration, such as when applying MACRS depreciation and bonus depreciation.

For instance, since the revenue from a typical solar or wind facility is usually received over a 25- to 30-year period, while the asset may be depreciated for tax purposes over a substantially shorter period (for instance, often over only a five-year period), tax losses are created in the early years of a typical transaction. This occurs with many tax-oriented transactions; however, most alternative energy assets are provided very short and favorable tax depreciation lives in comparison to their actual lives.

These tax losses enable the transaction to create hypothetical tax refunds insofar as the specific transaction is concerned, when such tax losses shelter other taxable income of the investor. Thus, the investor saves tax dollars temporarily — until the asset is fully depreciated and the revenues are then no longer offset by tax depreciation.

It should be noted that these transactions cannot be structured purely for tax avoidance purposes. Under the tax code, transactions must have economic substance behind them. Hence, when analyzing any transaction for tax qualification purposes, the investor must ensure that the transactions demonstrate a positive cash return.

In other words, a transaction cannot be funded purely by tax benefits. Thus, under a tax-oriented lease or a service agreement, one must demonstrate an anticipated positive cash flow of the project using supportable financial models in order for tax counsel to obtain comfort that the transactions will be respected, for tax purposes, as having sufficient economic substance.

To better understand the economics of a typical tax-oriented lease or service contract of an alternative energy project, one can look at a very basic example. Without considering the time value of money, in basic terms, an investment would need to receive tax credits plus cash revenues to pay back the asset investment plus an after-tax yield. The tax depreciation creates a further benefit in deferring the paying of some income taxes on the investment.

So, using a very basic example, let us consider how much of an investment would have to be paid back if an investor invested $100 million in a qualifying alternative energy facility and seeks an 11.80% after-tax yield. In this example, the investment is eligible for 100% bonus depreciation and a 30% ITC. For purposes of simplicity, we will assume that there is no tax basis reduction attributable to the ITC.

The objective of this article is to provide insight into the accounting for alternative energy investments. Therefore, at this time we will not address specifically how to deal with the tax accounting pertaining to the basis reduction when claiming the ITC, although a follow-on section will address it in general terms. Note also that this example has been created so that the transaction generates a positive cash return of at least 2%.

The positive cash flow test is found in Rev. Proc. 2001–28/29 and is generally also applied by tax counsels when examining service contracts to ensure that the transaction has economic substance and has not be structured solely for tax avoidance purposes. Generally, for analytical purposes, tax counsels consider ITC the equivalent of cash; hence, in the example below the $72 plus $30 of ITC provide cash proceeds of $102, or 102% of the investment cost.

In this simplistic case the gross cash revenues required to repay the investment would be only $72 million or 72% of the initial investment, calculated as follows:

	Millions
Out-of-pocket facility acquisition cost	$100.00
Plus: targeted after-tax return	11.80
Less: 30% ITC	(30.00)
Less: 100% bonus depreciation benefits calculated as	
($100 × 35%)	(35.00)
Net after-tax investment to recover	$ 46.80

Thus, the remaining $46.8 million would need to be recovered on an after-tax basis by charging rents in the case of a lease or revenues in the case of PPA. The rents or PPA revenues would be taxed at the federal statutory rate of 35%, so in order to recover the above $46.8 million on an after-tax basis, one would need to collect rents or PPA revenues totaling $72 million, representing the grossed up after-tax recovery. The $72 million is calculated by simply dividing the after-tax revenue of $46.8 million needed by 65% (100% gross revenues – 35% tax rate = 65% after-tax proceeds).

This simplified view of a complex after-tax analysis then equates to the following basic income statement shown in Table 2.

For clarity purposes, note that the tax provision, which would usually be an "expense" or reduction from gross profit, is in this case a negative provision or, put another way, a tax benefit.

It is clear from this very basic accounting/financial statement summary that in order to obtain the $11.8 million after-tax return on the $100 million initial investment, the facility needs to generate only $72 million of gross taxable revenues. However, since the initial out-of-pocket investment is $100 million, that amount must be depreciated for book purposes. This example illustrates one of the fundamental challenges with these transactions, aside even from the inherent conceptual complexities and risk analysis.

Although this example was created with an 11.8% return, actual and more complex structures are generating an approximate 8% after-tax return, given the costs of originating and documenting such a transaction. Even though the 8% return is currently considered a very respectable return, many potential investors often are challenged by the above financial statement presentation.

Service Contract Accounting

If the financing transaction is considered a service contract, the accounting looks very much like an operating lease, with the exception of how the revenue is reported. The first analysis required is to determine if the nature of the transaction falls outside the scope of lease accounting and if the transaction thus should be reported as a service contract. We will assume that the transaction in Table 2 is a service contract, given the very basic rationale that the off-taker is merely purchasing the variable output of the facility rather than paying lease payments to use it.

As stated above, under a typical alternative energy service agreement, the off-taker starts by paying a rate per kilowatt hour of electricity, which is usually less than the rate per kilowatt the off-taker would otherwise pay in the open market. The PPA contract rate typically increases each year based on the assumed

Table 2. Basic Income Statement of a Typical Alternative Energy Project (millions of dollars)

Revenues required	$ 72.00
Book depreciation	(100.00)
Pretax book income (loss)	(28.00)
Less: tax provision (benefit) composed of:	
Investment tax credit	30.00
Tax provision (benefit) (35% × $28.00)	9.80
Total tax provision (benefit)	39.80
Net after-tax income	$ 11.80

increase in general energy costs for a 25- to 30-year contract — for example, a typical increase is approximately 2% per year.

Once it has been determined that the accounting for the service contract falls outside the scope of the lease accounting standard, the revenue recognition standard, specifically Accounting Standards Codification (ASC) Topic 606, Revenue from Contracts with Customers, will be applied. In basic terms, under revenue recognition, revenues are earned when the services have been delivered.

Assuming the energy generation of the facility is somewhat consistent but the PPA rates increase periodically based on the PPA schedule, the gross revenue from the transaction will generally start at its lowest point and increase gradually, similar to that illustrated in Table 3. For purposes of this initial presentation, the accounting for the ITC has not been included.

As Table 3 shows, because a substantial portion of the financial return from the investment is originating from the ITC, the transaction has a pretax book loss. As part of the accounting for the investment, one must consider whether it is also necessary to record an impairment of the asset, since this financial model indicates there would be a permanent impairment in the asset as compared to the cash revenues it is expected to generate.

In the model in Table 4, the impairment has been added so that the project would show no pretax loss overall. Also, the impairment would likely be required to be recorded early in the life of the transaction, perhaps even within the first year. This financial statement illustrates the effect such impairment would have on the periodic financial results.

As can be seen in Table 4, the asset impairment would create a significant pretax book loss in the first year of the transaction, with subsequent year earnings potentially increasing gradually over the life of the transaction. Under a service contract, the asset owner is responsible for maintaining the asset. Thus in an actual financial model of a service contract, the revenues would likely be somewhat greater than a lease, but the service contract would also include operating expenses, such as the costs of a maintenance contract.

However, such operating expenses have not been included in this service contract model simply so that one can compare the same transactions with different accounting results. The accounting for a service contract with ITC will be addressed in the ITC accounting section.

As was discussed above, the production tax credit is available only for the producer of energy. For this reason, PTC is only available under a service contract. When a developer does not have substantially sufficient tax capacity to absorb and utilize the PTC, it will often monetize it in the tax-equity flip partnership structures discussed above. Because the partnership is a pass-through tax entity, income taxes are not provided for at the partnership level but

Table 3. Service Contract, Without Asset Impairment and Without ITC Accounting (millions of dollars)

	Totals	Year 1	Year 2	Year 3	Year 4	Years 5–20
Revenues	72.00	2.96	3.02	3.08	3.14	59.80
Depreciation	(100.00)	(5.00)	(5.00)	(5.00)	(5.00)	(80.00)
Gross profit/(loss)	(28.00)	(2.04)	(1.98)	(1.92)	(1.86)	(20.20)
Tax provision/benefit	9.80	0.71	0.69	0.67	0.65	7.08
Net income/loss	(18.20)	(1.33)	(1.29)	(1.25)	(1.21)	(13.12)
Tax provision (ITC)	30.00					
Net income	11.80					

Table 4. Service Contract, With Asset Impairment and Without ITC Accounting (millions of dollars)

	Totals	Year 1	Year 2	Year 3	Year 4	Years 5–20
Revenues	72.00	2.96	3.02	3.08	3.14	59.80
Asset impairment	(28.00)	(28.00)	0	0	0	0
Depreciation	(72.00)	(3.60)	(3.60)	(3.60)	(3.60)	(57.60)
Gross profit/(loss)	(28.00)	(28.64)	(0.58)	(0.52)	(0.46)	2.20
Tax provision (benefit)	9.80	10.02	0.20	0.18	0.16	(0.76)
Income/loss before ITC	(18.20)	(18.62)	(0.38)	(0.34)	(0.30)	1.44
Tax provision (ITC)	30.00					
Net income	11.80					

are provided for individually, by each partner.

Table 5 is structured to illustrate the accounting for a service contract where the facility is owned fully by a taxable entity and the entity is claiming the PTC rather than the ITC. The PTC is generated based on the production of electricity, so it would have a somewhat direct relationship to the amount of revenue being produced. There is no specification as to the treatment of the PTC other than that contained in ASC 740, Income Taxes. The PTC is to be recognized as a credit that flows through the tax provision.

Generally, the PTC would provide a greater overall credit than the ITC. For illustrative purposes, the PTC is assumed to be equal to the ITC and is recognized proportionately to the revenue so that each model has a consistent amount of income and taxes.

In the case of a service contract, the asset will likely be written down in the first year, because its value is not expected to be recovered by the gross revenue from electricity sales over the life of the project.

This situation again illustrates the challenge in the financial statement presentation. That is, even though the PTC is recognized proportionately to the energy revenues, because it resides below the gross profit line, the transaction presents a pretax loss but an after-tax profit.

Operating Lease Accounting

Often, the leases of alternative energy assets are not accounted for as an operating lease simply because it would require the lessor to retain and record a substantial residual value associated with the asset. Given the terms of the transactions, in order for that booked residual value to be high enough for the transaction to be recorded as an operating lease, the recorded residual value would likely have to be in excess of 20%.

Alternative energy projects generally have little value deinstalled; rather, their value is maximized on an in-use, in-place basis producing electricity. Most lessors book conservative residual values so that if the assets are indeed returned, there is little risk for a loss on the disposition of the deinstalled assets.

Nonetheless, assuming the transaction meets the definition of an operating lease, its financial statement presentation would appear very much like the service contract model shown in Table 5, except that the revenues would be level over the life of the transaction.

Because the objective of this article is to illustrate the differences in the accounting for similar transactions, for illustration purposes the same basic model assumptions will be shown. Table 6 presents what the financial statements would look like for the same transaction but recorded as an operating lease. Recall that only the ITC is available for a transaction structured as a lease.

As can be seen from Table 6, the results would present a large loss in the first year of the transaction, along with little to no

Table 5. Service Contract, With Asset Impairment and PTC Accounting (millions of dollars)

	Totals	Year 1	Year 2	Year 3	Year 4	Years 5–20
Revenues	72.00	2.96	3.02	3.08	3.14	59.80
Asset impairment	(28.00)	(28.00)	0	0	0	0
Depreciation	(72.00)	(3.60)	(3.60)	(3.60)	(3.60)	(57.60)
Gross profit/(loss)	(28.00)	(28.64)	(0.58)	(0.52)	(0.46)	2.20
Tax provision						
Based on income	9.80	10.02	0.20	0.18	0.16	(0.76)
PTC	30.00	1.23	1.26	1.28	1.31	24.92
Total tax provision	39.80	11.25	1.46	1.46	1.47	24.16
Net income/loss	11.80	(17.39)	0.88	0.94	1.01	26.36

Table 6. Operating Lease, With Asset Impairment and Without ITC Accounting (millions of dollars)

	Totals	Year 1	Year 2	Year 3	Year 4	Years 5–20
Revenues	72.00	3.60	3.60	3.60	3.60	57.60
Asset impairment	(28.00)	(28.00)	0	0	0	0
Depreciation	(72.00)	(3.60)	(3.60)	(3.60)	(3.60)	(57.60)
Gross profit/(loss)	(28.00)	(28.00)	0	0	0	0
Tax provision (benefit)	9.80	9.80	0	0	0	0
Income/loss before ITC	(18.20)	(18.20)	0	0	0	0
Tax credit (benefit)	30.00					
Net income after taxes	11.80					

net income in subsequent years. This does not appear to be a reasonable financial statement presentation, given that the asset is producing revenue over its entire lifetime whereas the pretax income appears to report a loss in the first year with no subsequent income.

The location of the tax credit in the income statement is largely the reporting issue here, another factor being that the transaction is heavily reliant on the tax benefits. The ITC accounting will be discussed below.

Direct Finance Lease Accounting
If the investment is reported as a direct finance lease, the gross finance revenues would be skewed more during the early years of the lease. Note that under ASC 840, the classification of a lease is determined at the inception of the lease.

A lease is classified as a direct finance lease if the present value of the lease payments is equal to or greater than 90% of the fair market value of the asset, less any ITC expected to be realized by the lessor. Thus, in this case, and since there is no residual value included in the assumptions, the lease would qualify as a finance lease. The present value of the minimum lease payments, discounted at the implicit interest rate in the lease, would by definition equal 100% of the fair market value of the asset net of ITC retained by the lessor.

Unfortunately, again, an unusual circumstance occurs here in that the implicit interest rate would be calculated as a very low rate, because the aggregate payments are not adequate to even repay for the investment net of the ITC. That is, using an HP–12C financial calculator or an Excel model, the implicit interest rate in the above example used to calculate the 90% test is only 0.95%, since the revenue payments are only \$72, while the asset's fair value less ITC is \$70. Thus, over a five-year period, the payments used to calculate the implicit interest rate are only \$2 over the asset cost.

After one determines that the lease is classified as a finance lease, under ASC 840, the finance income is then amortized using the rate that would amortize the initial investment (\$100) down to the residual value at the end of the lease. In that case, the rate to amortize the initial investment down to zero given the payments included is actually a negative 2.9435%, since again the revenues of \$72 are inadequate to amortize the initial investment of \$100 down to zero.

Although the ITC is an integral component of the pricing of alternative energy investments, under current GAAP the ITC is not used to reduce the value of the investment when amortizing the finance income.

Table 7 illustrates what such a transaction would look like, amortizing the investment with the negative implicit interest rate.

Once again, we see that the financial statement presentation would present a pretax book loss in each of the years illustrated in Table 7. The cause of the pretax book loss is that the investments are subsidized by the substantial investment tax benefits provided by the U.S. Treasury and are not recovered through the revenues from the asset itself.

In order to achieve a positive or even neutral finance revenue, the value of the investment would have to be written down in year 1. Assuming the principal portion of the investment is again impaired to the extent of the \$28 total loss, the model would report no finance revenues at all during its term, and the total tax benefit of \$9.80 would be recorded in the first year.

Thus, it appears that regardless of the manner in which these investments are accounted for, the challenges in the financial statement presentation relate to the fact that their returns are largely the result of generous tax benefits and how the tax benefits are accounted for.

Accounting for the Investment Tax Credit

So far, we have not addressed the accounting for the ITC, only for the PTC (Table 5). The accounting for the PTC with respect to its timing is fixed, in the sense that it is earned only when revenues are produced. We next examine the authoritative literature pertaining to the accounting for the ITC over the term of the transactions, and then we will apply the different methods available under GAAP to examine how the financial results appear on a periodic basis.

ITC as Discussed Within Income Tax Accounting (ASC 740)
Under U.S. GAAP, there is scant information concerning the

Table 7. Finance Lease, Without ITC Accounting (millions of dollars)

	Totals	Year 1	Year 2	Year 3	Year 4	Years 5–20
Finance revenues	(28.00)	(2.94)	(2.75)	(2.56)	(2.38)	(17.37)
Tax provision (benefit)	9.80	1.03	0.96	0.90	0.83	6.08
Income/loss before ITC	(18.20)	(1.91)	(1.79)	(1.66)	(1.55)	(11.29)
Tax credit (benefit)	30.00					
Net income after taxes	11.80					

accounting for ITC and none specifically addressing the type of situations found with alternative energy investments. ITC is addressed within ASC 740, Income Taxes, and briefly within ASC 840, Leases. The accounting for ITC as stipulated in ASC 740 will be summarized and illustrated first.

With respect to the income statement effect, the ASC 740–10–25–46 states that the ITC shall be reflected in net income. There are two specified methods for the accounting for the ITC: (1) the deferral method and (2) the flow-through method. Under the deferral method, the ITC is reflected in net income over the productive life of the asset.

The deferral method is stated to be the preferable method within the ASC; however, the ASC indicates that the flow-through method is also acceptable. Under the flow-through method, the ITC can simply be treated as a reduction of federal income taxes in the year in which the credit arises. The deferral method is generally considered preferable because it matches the revenue and expense streams associated with the underlying transaction.

Within ASC 740–10–25–20, paragraph (f) is a reference that can easily be missed because it does not specifically address the accounting for the ITC. That paragraph states,

> *Investment tax credits accounted for by the deferral method.* Under the deferral method as established in paragraph 740–10–25–46, investment tax credits are viewed and accounted for *as a reduction of the cost of the related asset (even though, for financial statement presentation, deferred investment tax credits may be reported as deferred income.)*[8] Amounts received upon future recovery of the reduced cost of the asset for financial reporting will be less than the tax basis of the asset, and the difference will be tax deductible when the asset is recovered.

Note that although ASC 740–10–25–46 addresses the treatment of the basic accounting for the ITC, ASC 740–10–25–20(f) also provides an opportunity for the statement preparer to use the deferred ITC created under the deferral method to reduce the *accounting* cost basis of the assets for which it pertained. That is, the original cost of the asset can be reduced dollar-for-dollar by the amount of the tax credit.

Also note that the accounting basis and the tax basis have different treatments regarding the basis reduction. Accounting for the book and tax basis differences results in a requirement to address how these differences affect the accounting for deferred taxes associated with the transactions. This is addressed below in the section Accounting for the Tax Effect of the Asset Basis Reduction.

When the ITC is reported all in one period and not deferred, it is following the flow-through method.

In journal entry form, the entry would be:

	Debit	Credit
Tax provision – current		30.00
Federal taxes payable – current	30.00	

to record the tax benefit from an ITC.

In this journal entry, the normal entry for the tax provision is a debit and the current federal taxes payable is a credit, but both are reduced here, reflecting that a tax benefit was received and the current tax provision, normally an "expense," was also reduced. If we were to take the example above, and assuming the transaction to which it is associated is an operating lease, the results would appear as shown in Table 8.

As one can see from the basic periodic financial statements in Table 8, the overall income from the transaction is the same, but the annual net income recognition of the transaction using the flow-through method to recognize the ITC provides for an uneven pattern of after-tax net income recognition.

Combined with the fact that the financial statement also shows a loss above the tax-provision line, one can see that there are inherent challenges to enter into a transaction of this nature from a financial reporting perspective. That is, although the transaction

Table 8. Operating Lease, Without Asset Impairment and With ITC, Using Flow-Through Method (millions of dollars)

	Totals	Year 1	Year 2	Year 3	Year 4	Years 5–20
Revenues	72.00	3.60	3.60	3.60	3.60	57.60
Depreciation	(100.00)	(5.00)	(5.00)	(5.00)	(5.00)	(80.00)
Gross profit/(loss)	(28.00)	(1.40)	(1.40)	(1.40)	(1.40)	(22.40)
Tax provision						
Based on income	9.80	0.49	0.49	0.49	0.49	7.84
ITC	30.00	30.00	0	0	0	0
Total tax provision	39.80	30.49	0.49	0.49	0.49	7.84
Net income after taxes	11.80	29.09	(0.91)	(0.91)	(0.91)	(14.56)

provides a healthy after-tax economic return, its periodic financial statement presentation is very uneven.

If the transaction in Table 8 were to be accounted for as a direct finance lease, the gross profit above the tax-provision line would reflect a different income pattern, but the tax provision would be even more distorted.

An additional issue with the presentation in Table 8 arises when one considers whether the asset itself should be impaired, given that the gross amount of the investment ($100 million in this case) may never be recovered from revenues. That is, because the ITC benefit is such a major element of the financial model, it is possible that the asset itself will never produce enough revenue to pay back the full $100 million. Thus, in Table 8, it might be necessary to record an up-front impairment in the value of the asset itself — for instance to write down the value of the asset to the point that no above-the-line loss would be recorded.

In that case, essentially the future year net losses would be moved into the first year, and the full-term net income of $11.8 million would thus be recorded in the first year, as illustrated in Table 9.

As one can see from Table 9, presenting net earnings as of only the first year of the transaction does not appear appropriate, given that the investment is considered to be an earning asset for its entire life. Perhaps a more appropriate approach would be to write down the asset even more than indicated above, such that in subsequent years a positive earnings pattern would be presented.

Again, the issue here arises from the fact that the ITC is so large that the investment would not create a positive return simply based on the cash flows from the revenues. In fact, most investors would view the ITC almost as if it were simply a nontaxable revenue item.

The basic ITC flow-through model can be easily adjusted to reflect the deferral method, which is stated to be a preferable method within the ASC, by simply spreading out the ITC over the 20-year term. ASC 740 recommends it be spread out over the life of the asset, so if this asset were a solar facility, the ITC would be spread out over possibly 20 to 25 years.

Following ASC 740–10–25–20 in journal entry form, the entry would be:

	Debit	Credit
Federal taxes payable – current	30.00	
Deferred income		30.00

to record the tax benefit from an ITC using the deferral method.

Subsequently, the deferred income constituting the deferred ITC would be absorbed into income over the life of the asset, either through the tax-provision line or included above the tax-provision line within revenues.

For purposes of this illustration, all elements have been spread out over 20 years and will be included in the tax-provision line.

Because the ITC is following the deferral method and in accordance with the reference in ASC 740–10–25–20, the deferred balance was used as an offset against the asset value, and an immediate asset write-down was not required. In this case, the ITC credit amortization is still being reported through the tax-provision line as a benefit.

What we see from this adjustment (illustrated in Table 10) to using the deferral method is that the pretax net income recognition pattern is now somewhat more uniform during the term of the agreement. However, again, the issue here is that a transaction with a very respectable overall net income is reporting above-the-pretax book results that appear illogical.

That said, one can conclude in general that from a net income perspective and assuming the transaction is accounted for as an operating lease, the net income appears more consistent with the accounting suggested by FASB in the current ASC

Table 9. Operating Lease, With Asset Impairment and With ITC, Using Flow-Through Method (millions of dollars)

	Totals	Year 1	Year 2	Year 3	Year 4	Years 5–20
Revenues	72.00	3.60	3.60	3.60	3.60	57.60
Asset impairment	(28.00)	(28.00)	0	0	0	0
Depreciation	(72.00)	(3.60)	(3.60)	(3.60)	(3.60)	(57.60)
Gross profit/(loss)	(28.00)	(28.00)	0	0	0	0
Tax provision						
Based on income	9.80	9.80	0	0	0	0
ITC	30.00	30.00	0	0	0	0
Total tax provision	39.80	39.80	0	0	0	0
Net income after taxes	11.80	11.80	0	0	0	0

840–20–25–1 approach. That is, under operating lease accounting, rents as well as depreciation are reported on a straight-line basis over the life of the lease.

Thus, by applying the deferral method of accounting for the ITC (which FASB acknowledges is a reduction of the cost of the asset), the overall net income pattern of the lease also is now on a straight-line basis over the lease term.

The last example presented with regard to the ITC method is Table 11. It is for a lease that will be accounted for as a finance lease, and it applies the deferral method in a manner consistent with the pretax book income recognition. Because the net income of all the lease models is always the same, the only difference in the presentation is the geography of where and how the income is reported. Thus, because under the operating lease and service contract models shown above, the pretax book loss is $28, similarly the pretax finance income will also be a book loss of $28, albeit allocated following a different reporting pattern.

Note that the after-tax income pattern now appears to be consistent with that experienced with a direct finance lease. However, again, the transaction presents an above-the-tax-line book loss. The finance income is negative because again, under conventional accounting standards, the revenues used to pay back the investment and earn a yield are less than the cost of the investment itself, if not for the substantial ITC.

ITC as Discussed in Current Lease Accounting Standard (ASC Topic 840)

The accounting for the ITC is addressed in the lease accounting standard only insofar as it relates to the accounting for leveraged leases. The lease accounting standard states,

> Unearned and deferred income consists of (1) the estimated pretax lease income (or loss), after deducting initial direct costs, remaining to be allocated to income over the lease term and (2) the investment tax credit remaining to be allocated to income over the lease term.

Thus, in the above language, the FASB has indicated that the ITC should be accounted for using the deferral method and that *it is an integral component of the asset investment.*

In fact, ASC 840 indicates that leveraged lease accounting is not permitted unless any ITC that is claimed is accounted for using the deferral method. The model illustrating accounting for leveraged leases contained within the ASC presents the amortization of the ITC following the leveraged lease method and flowing through the tax-provision line. The ASC illustration includes the deferred ITC within the definition of "investment in leveraged leases" and within the presentation in the financial statements as a reduction in the investment basis.

Hence, applying at least these aspects of the accounting for ITC could potentially assist in certain aspects of the accounting issues — for instance, by using the deferred ITC credit as a reduction of the asset investment balance, thus potentially

Table 10. Operating Lease, Without Asset Impairment and With ITC, Using Deferral Method (millions of dollars)

	Totals	Year 1	Year 2	Year 3	Year 4	Years 5–20
Revenues	72.00	3.60	3.60	3.60	3.60	57.60
Depreciation	(100.00)	(5.00)	(5.00)	(5.00)	(5.00)	(80.00)
Gross profit/(loss)	(28.00)	(1.40)	(1.40)	(1.40)	(1.40)	(22.40)
Tax provision						
Based on income	9.80	0.49	0.49	0.49	0.49	7.84
ITC	30.00	1.50	1.50	1.50	1.50	24.00
Total tax provision	39.80	1.99	1.99	1.99	1.99	31.84
Net income after taxes	11.80	0.59	0.59	0.59	0.59	9.44

Table 11. Finance Lease, With ITC, Using Deferral Method (millions of dollars)

	Totals	Year 1	Year 2	Year 3	Year 4	Years 5–20
Finance revenues	(28.00)	(2.94)	(2.75)	(2.56)	(2.38)	(17.37)
Tax provision						
Based on income	9.80	1.03	0.96	0.90	0.83	6.08
ITC	30.00	3.15	2.95	2.74	2.55	18.61
Total tax provision	39.80	4.18	3.91	3.64	3.38	24.69
Net income after taxes	11.80	1.24	1.16	1.08	1.00	7.32

avoiding a write-down of the asset and addressing one of the accounting problems. By way of explanation, the asset cost of $100 would be reduced by the $30 ITC, on the theory that the ITC was provided to reduce the cost of the asset and is an integral component of the asset investment, as discussed above.

To illustrate this approach, here is a financial statement using the deferred tax credit as an offset against the asset value so as to avoid the write-down. Following the approach discussed above in journal entry form, the entry would be:

	Debit	Credit
Federal taxes payable – current	30.00	
Fixed asset		30.00

to record the tax benefit from an ITC as a reduction in the cost basis of the asset.

The situation shown in Table 12 presents another unusual circumstance in that the tax provision must be calculated only against the taxable portions of the transaction. That is, the tax provision is calculated after subtracting any tax-exempt or nontaxable income. The tax provision in the aggregate is calculated as follows:

Income before taxes	2.00
Less: nontaxable income (ITC)	(30.00)
Taxable income (loss)	(28.00)
Tax benefit @ 35%	9.80

Thus, the portion of the tax provision related only to the taxable income is the same as in all the other examples, because moving the tax credit above the tax line as an adjustment of the asset cost still requires an adjustment to that amount when calculating the tax provision. No matter where the tax credit is placed on the income statement, the taxable income itself remains the same.

So, in this case there is a minor amount of above-the-line book income because, although the asset value was reduced by the tax credit, the transaction still relies on the tax benefits to achieve its after-tax income. Even though moving the tax credit above the tax line marginally improves the pretax book income, it still does not present a result that would appear favorable to management due to the low pretax yield.

ITC as Discussed in ELFA Comment on New Lease Accounting Standard (ASC Topic 842 Pending)

In a comment letter dated February 27, 2015, to FASB, ELFA requested that FASB address the accounting of the ITC within the new lease accounting standards. The ELFA comment letter addressed specific technical publications considering the treatment of ITC in the context of a financing transaction.

The comment letter referred first to the PricewaterhouseCoopers (PwC) Accounting and Reporting Manual (ARM). The ARM is an interpretive guide for financial reporting often used by PwC clients as well as PwC staff. The comment letter indicated that within section 4650.3111, Direct Financing Lease, PwC acknowledges that the

> … great weight of practice in the banking industry is to offset it *[the ITC[9]]* against the net investment *(in the direct finance lease[10])*. With respect to its presentation in the income statement, it may be presented as an element of income tax expense, or it may be included in revenue. The AICPA Industry Audit Guide, "Audits of Banks," recognizes this dichotomy in practice and merely recommends disclosure of the method followed.

The ELFA letter then draws an analogy to grant accounting addressed under International Financial Reporting Standards (IFRS), specifically International Accounting Standard (IAS) 20, Accounting for Government Grants and Disclosures of Government Assistance. IAS 20 was used as a proxy for accounting for U.S Treasury Section 1603 cash grants received in lieu of ITC because U.S. GAAP did not address the accounting for such cash grants. IAS 20 provided for two options for accounting for the grant: (1) as a deferred income item or (2) as a deduction from the asset's carrying amount. Thus, when U.S. GAAP reporting entities received 1603 grants in lieu of ITC, they tended to apply one of those two methods for recognizing the 1603 grant.

Accordingly, ELFA has requested that FASB address the accounting for the ITC in the forthcoming lease accounting standards, which were to be issued in February 2016. Whether or

Table 12. Operating Lease, ITC as Reduction to Cost of the Asset (millions of dollars)

	Totals	Year 1	Year 2	Year 3	Year 4	Years 5–20
Revenues	72.00	3.60	3.60	3.60	3.60	57.60
Depreciation	(70.00)	(3.50)	(3.50)	(3.50)	(3.50)	(56.00)
Gross profit/(loss)	2.00	0.10	0.10	0.10	0.10	1.60
Tax provision						
Based on book income	(0.72)	(0.04)	(0.04)	(0.04)	(0.04)	(0.56)
Based on nontaxable income	10.52	0.53	0.53	0.53	0.53	8.40
Total tax provision	9.80	0.49	0.49	0.49	0.49	7.84
Net income after taxes	11.80	0.59	0.59	0.59	0.59	9.44

not FASB does so, for a large segment of the investors in alternative energy projects that structure their projects using a financing structure other than a lease — including a wholly owned service contract arrangement or a participation in a tax-equity flip partnership structure — the new lease accounting standard would not be directly applicable: it would be relevant only through analogy.

In other words, because FASB is addressing lease accounting only, even if it addresses the accounting for the ITC within a lease, it likely would not address the accounting for the ITC in either a service contract or tax-equity flip partnership structure, both of which generally represent the majority of transactions financing alternative energy projects.

Nonetheless, Table 13 presents the service contract example applying the approach acknowledged in the PwC Accounting and Reporting Guide: that is, moving the ITC into the revenue line on the income statement.

Granted, this approach still presents a situation where the above-the-pretax income from the transaction is not extremely profitable without the benefit of a negative tax provision, but at least it moves a large amount of the benefit above the tax line and eliminates the pretax loss. In the Table 13 example, the ITC amortization is treated as a nontaxable component of the gross revenue, but this treatment still cannot address the fact that much of the income derives from the negative tax provision.

Specific transactions vary in their characteristics such that the amount of the above-the-line income or loss will vary by transaction. However, the objective of this article and these numerous examples is to illustrate to the reader that there is a different approach to rationalizing making an economically attractive investment that, nonetheless, has unusual financial statement reporting results.

Changing From the ITC Flow-Through Method to the Deferral Method

Occasionally, a company has previously elected an ITC methodology (deferral or flow-through) elsewhere in the company, for instance when a parent bank or parent manufacturer elects the flow-through method for accounting for the ITC. In that case, the bank leasing subsidiary or captive leasing subsidiary may conclude that it also must follow that approach under the guise of the consistent application of accounting principles within the same legal entity.

A consistent application of GAAP by a reporting entity and among consolidated reporting entities is generally required. However, if the nature of a transaction or the business of the operating entity is substantially different from that of its parent and the financial presentation is preferable, then using a different approach is acceptable. Thus, a captive financing subsidiary of an industrial company may be able to follow the deferral method of accounting for the ITC for financing transactions while its parent may be able to follow the flow-through method.

Under ASC 250, Accounting Changes and Error Corrections, changing from one method of accounting to another is acceptable provided that the change is demonstrably preferable and appropriate disclosures are provided. ASC 250–10–45–2 states,

> A reporting entity shall change an accounting principle only if either of the following applies;
>
> a. The change is required by a newly issued Codification update.
>
> b. The entity can justify the use of an allowable alternative accounting principle on the basis that it is preferable.

Thus, if a captive financing subsidiary is adopting an accounting approach for the ITC for the first time, the captive may be able to select the deferral method while its parent uses the flow-through method based on justification (b) above, namely that the allowable alternative principle is preferable for its type of business because it conforms to the suggestion in ASC 740 that the deferral approach is preferable and because its recognition matches the life of the asset on which it is based.

Moreover, if the subsidiary had already recorded some transactions that used the flow-through method, it might be able to make sufficiently substantive arguments to its auditors that the deferral method is prefera-

Table 13. Operating Lease, Deferred ITC Amortized Into Revenue Line (millions of dollars)

	Totals	Year 1	Year 2	Year 3	Year 4	Years 5–20
Revenues	102.00	5.10	5.10	5.10	5.10	81.60
Depreciation	(100.00)	(5.00)	(5.00)	(5.00)	(5.00)	(80.00)
Gross profit/(loss)	2.00	0.10	0.10	0.10	0.10	1.60
Tax provision						
Based on book income	(0.72)	(0.04)	(0.04)	(0.04)	(0.04)	(0.56)
Based on nontaxable income	10.52	0.53	0.53	0.53	0.53	8.40
Total tax provision	9.80	0.49	0.49	0.49	0.49	7.84
Net income after taxes	11.80	0.59	0.59	0.59	0.59	9.44

ble. Generally speaking, most financing companies use the deferral method of accounting for the ITC because of all the financial reporting issues shown in the examples above.

Accounting for the Tax Effect of the Asset Basis Reduction

Normally, when an asset is first acquired, its book basis is the same as the tax basis. Given that book depreciation and tax depreciation typically follow different schedules, the difference between the book depreciation reported and the tax depreciation reported creates temporary tax timing differences that are tracked over the life of the asset. After applying the statutory tax rate to the timing differences, a deferred tax liability associated with the timing differences is created.

Under ASC 740, the tax provision (expense) should be equal to the book income multiplied by the estimated effective tax rate. Thus, the deferred tax liability represents the amount of taxes that will be due at some time in the future, as compared to the amount of tax expense calculated based on the book income.

Ultimately, when both the book basis and the tax basis of the asset are fully depreciated for each respective purpose, the deferred tax liability is eliminated; that is, the taxes that had been deferred have become currently due. Table 14 illustrates the creation of and reversal of a deferred tax liability from the use of different book and tax depreciation approaches for a $100,000 asset.

As was discussed earlier, when the ITC is claimed, the tax basis of the asset must be reduced by one-half the value of the ITC. This is a called a *permanent* difference, in that the book basis of the asset will permanently be different than the tax basis of the asset. A permanent difference does not create a deferred tax asset or liability. Rather, a permanent difference affects the effective tax rate. The effective tax rate is the weighted average rate that is applied to income before taxes to arrive at the proper tax provision amount. For instance, if an entity has a large amount of tax-exempt income, its effective tax rate would be lower than the statutory rate because the tax-exempt income is not taxed.

The effective tax rate is applied to net income before taxes as a means of calculating the overall tax provision. When pricing, modeling the results, and accounting for an individual transaction, the same usually applies. Financial models usually apply an effective tax rate to the overall income before taxes to arrive at the gross tax-provision amount.

When a permanent difference exists between book income and taxable income, it is often a challenge to determine and maintain the effective tax rate, especially for a transaction where the amount of the income changes over the life of the transaction, such as with a service agreement. Furthermore, most entities calculate the tax provision based on the overall income before taxes of a business unit, not on an individual transaction — hence the challenge in handling these permanent differences embedded within a transaction.

Table 15 illustrates what occurs with a difference in the book and tax basis of an asset.

As Table 15 shows, the asset tax basis has been reduced by $15,000, representing half of the 30% ITC. Thus, the MACRS depreciation is then applied against the reduced tax basis of $85,000.

Most of the pricing and lease tracking systems that are used to manage these transactions cannot handle a permanent difference in the effective tax rate, because most standard tax-oriented transactions do not usually have a permanent difference. Therefore, the systems assume the creation of a deferred tax liability.

As can be seen in Table 15, the amount of the deferred tax liability that is created is not ultimately eliminated over the asset

Table 14. Basic Illustration of Deferred Taxes Over a Transaction Life

Year	Book depreciation	Tax depreciation	Timing difference	Deferred tax effect @ 35%	Cumulative deferred tax liability
1	10,000	20,000	(10,000)	(3,500)	(3,500)
2	10,000	32,000	(22,000)	(7,700)	(11,200)
3	10,000	19,200	(9,200)	(3,220)	(14,420)
4	10,000	11,520	(1,520)	(532)	(14,952)
5	10,000	11,520	(1,520)	(532)	(15,484)
6	10,000	5,760	4,240	1,484	(14,000)
7	10,000	0	10,000	3,500	(10,500)
8	10,000	0	10,000	3,500	(7,000)
9	10,000	0	10,000	3,500	(3,500)
10	10,000	0	10,000	3,500	0
	100,000	100,000	0	0	

life and in fact would not eliminate until the asset is disposed of. That is, the deferred tax liability remains on the books until the asset is ultimately sold, at which time the balance must be removed since there is no longer an asset on which it is based.

This basis difference makes it appear as if a greater tax refund related to the depreciation is due than would actually be receivable, because the book depreciation is greater than the tax depreciation. As a point of reference, the initial journal entry to record the initial tax provision insofar as the tax depreciation is concerned is as follows:

Account	Debit	Credit	Calculation
Taxes payable – current	5,950		(17,000 × 35%)
Tax provision – current		5,950	
Tax provision – deferred	2,450		(5,950 – (10,000 × 35%))
Taxes payable – deferred		2,450	

Since the tax provision is usually calculated on the transaction taken as a whole, this entry is provided to illustrate the isolated effect of the permanent difference.

ASC 740 addresses how to account for the tax effect of the basis difference based on whether the ITC is accounted for using the flow-through method or using the deferral method. If the flow-through method is selected, the initial deferred tax difference is adjusted up front as an adjustment to the tax provision, with the offsetting credit entry to the deferred tax liability balance. That is, a larger tax provision amount is recorded immediately so that the deferred tax liability is created immediately.

Because the tax returns represent the actual amounts to be paid, either currently or in the future, the adjustment is recorded to ensure that the deferred tax liability represents the liability to be paid over the asset life. In the above example and assuming the flow-through method is used, an entry would be recorded immediately to reflect the tax effect of the basis difference.

The journal entry to correct the deferred tax liability balance would then be:

Account	Debit	Credit	Calculation
Tax provision – deferred	5,250		(15,000 × 35%)
Taxes payable – deferred		5,250	

To adjust deferred taxes for the basis difference.

If the ITC is accounted for using the deferral method, ASC 740 indicates that the tax effect of the tax and book basis difference should likewise be adjusted over the life of the asset. This assumes that it is possible to isolate the tax effect of the asset basis difference from the tax effect of the transaction taken as a whole.

The basis adjustment could be taken into consideration individually for this transaction by simply applying the actual effective tax rate insofar as the asset basis component of the transaction is concerned. That is, instead of multiplying a 35% tax rate to the book depreciation, one could apply a 29.75% effective tax rate, which was calculated by multiplying the 85% tax basis × the 35% statutory rate. In this fashion, the tax basis difference is accounted for over the life of the transaction rather than up front, consistent with the treatment of the deferral method of accounting for the ITC.

Unfortunately, the example in Table 16 has the benefit of isolating a single element of a transaction, namely the book-tax basis difference of the asset. Most companies determine the tax provision by applying the statutory tax rate to the pretax book income of the transaction and track the timing differences separately. Thus, this adjustment must be considered

Table 15. Effect of Book-Tax Basis Difference on Deferred Taxes

Year	Book depreciation	Tax depreciation	Timing difference	Deferred tax effect @ 35%	Cumulative deferred tax liability
1	10,000	17,000	(7,000)	(2,450)	(2,450)
2	10,000	27,200	(17,200)	(6,020)	(8,470)
3	10,000	16,320	(6,320)	(2,212)	(10,682)
4	10,000	9,792	208	73	(10,609)
5	10,000	9,792	208	73	(10,536)
6	10,000	4,896	5,104	1,786	(8,750)
7	10,000	0	10,000	3,500	(5,250)
8	10,000	0	10,000	3,500	(1,750)
9	10,000	0	10,000	3,500	1,750
10	10,000	0	10,000	3,500	5,250
	100,000	85,000	15,000	5,250	

at the aggregate transaction level including other elements of income and expenses — or even over multiple transactions in a portfolio.

The effect of the book-tax basis difference is an additional element of complexity caused by the asset basis difference when accounting for alternative energy investments that claim the ITC.

Tax-Equity Flip Partnership Structures

Fundamental Economics of a Tax-Equity Flip Partnership

Before examining the accounting for an investment in a tax-equity flip partnership structure, one must examine the economics to better understand precisely what is happening and where the yield originates from. Recall that a tax-equity flip partnership structure goes through several different phases during the investment, and it has specified points in time when the allocations of cash flows and tax benefits flip between the partners.

As stated above, economically a tax-equity flip-partner investor obtains its after-tax return through a combination of cash distributions and allocated tax credits and tax losses. The allocated tax credits and the after-tax effect of tax losses equate to a cash equivalent for purposes of the after-tax return. That is, they are looked upon as if they were cash.

For example, $100 of allocated tax losses taxed at a 40% rate equates to a $40 cash-equivalent benefit. The partnership itself generates free cash flows as well as large amounts of tax losses in the early years of the transaction as well as tax credits similar to what was illustrated under the single-investor transaction above.

However, in the case of the tax-equity partner, rather than the partnership earning the return by itself, the sources of after-tax income and tax credits are initially allocated on a preferential basis to the tax-equity partner.

In an earlier section, Tax-Equity Flip Partnership, we presented a basic example where a tax-equity partner invested $50 million into an ITC project and was returned $35.59 million from its allocated ITC and tax benefits in the first year. That was an extreme example used to illustrate the basic fundamentals.

When applying those fundamentals into an actual transaction, the results are similar but not precisely as simple. Most wind transactions tend to be financed using tax-equity flip partnership structures claiming PTC, which, because it is earned over 10 years, tend to present a longer time to achieve the targeted return.

For purposes of illustrating how the tax-equity partner earns its return, the appendix to this article offers an accounting example of an actual tax-equity partnership transaction. It illustrates the accounting under U.S. GAAP; however, it also includes the information needed to understand how the economic yield is achieved. The model presented is a PTC structure. Most wind transactions are PTC structures because they are usually of a size where the PTCs provide a greater present-value return when compared to an ITC structure.

Using the information contained in the appendix, we isolated the cash-equivalent items to determine the after-tax internal rate of return (AT-IRR) that the tax-equity investor partner would earn. The tax losses allocated to the tax-equity investor partner were calculated simply by taking the difference between the starting and ending capital account balances from year to year as calculated in step 4 of the appendix. Because there are no cash distributions in that time frame, the change in the capital account represents allocated tax losses.

By the sixth year, the asset is mostly depreciated for tax purposes, so the facility starts generating taxable income. The taxable income is still allocated to the tax-equity investor because the facility is still gener-

Table 16. Using an Effective Tax Rate Adjustment to Consider Book-Tax Basis Difference

Year	Book depreciation	Tax depreciation	Timing difference	Deferred tax effect @ 29.75%	Cumulative deferred tax
1	10,000	17,000	(7,000)	(2,083)	(2,083)
2	10,000	27,200	(17,200)	(5,117)	(7,200)
3	10,000	16,320	(6,320)	(1,880)	(9,080)
4	10,000	9,792	208	62	(9,018)
5	10,000	9,792	208	62	(8,956)
6	10,000	4,896	5,104	1,518	(7,438)
7	10,000	0	10,000	2,975	(4,463)
8	10,000	0	10,000	2,975	(1,488)
9	10,000	0	10,000	2,975	1,488
10	10,000	0	10,000	2,975	4,463
	100,000	85,000	15,000	4,463	0

ating PTCs that are mostly allocated to the tax-equity investor partner. These PTCs continue to exceed the taxes that the partner would need to pay as a result of the continuing allocation of what is now taxable income rather than a taxable loss. That is, the PTCs still provide the tax-equity investor partner with a positive cash and cash-equivalent flow in excess of the taxes the partner must pay for the allocated taxable income.

As Table 17 shows, the flip of tax and cash allocations occurs around the 11th year, when the PTCs have expired.

To determine the AT-IRR to the tax-equity investor, the cash-equivalent value is assigned to the allocated tax benefits. The actual tax-equity partnership models calculate this either quarterly or monthly, so the level of exactitude is much more precise. That said, again recognize that this is a forecasted plan and not a contractual obligation on the part of the off-taker. Actual performance depends on any number of variables. Nonetheless, the starting point for negotiating the investment is the financial model, the net summary of which is included in the appendix.

Using a basic Excel financial model and using the cash flows included in the last column in Table 17 to calculate the IRR, it was determined that the IRR through the 11th year was approximately 10.08%, which obviously is greater than the 8% AT-IRR typically targeted in this market. Note also that the financial model in the appendix actually extends out to 20 years and beyond, even though the PTC sunsets after 10 years.

Table 17. Illustration of Cash and Cash-Equivalent Flows in a Tax-Equity Flip Partnership (millions of dollars)

Year	Allocated tax losses /(gains)	Cash equivalent @ 40%	Allocated PTCs	Allocated free cash	Total cash & cash equivalents
0	Investment				-99,996
1	55,139	22,056	3,816	0	25,872
2	28,209	11,284	7,979	0	19,263
3	11,919	4,768	7,979	0	12,747
4	8,666	3,466	8,326	0	11,792
5	2,205	882	8,326	0	9,208
6	7	3	8,672	0	8,675
7	-13,665	-5,466	8,672	13,672	16,878
8	-13,939	-5,576	9,019	13,947	17,390
9	-14,218	-5,687	9,019	14,227	17,559
10	-14,509	-5,804	9,366	14,513	18,075
11	-13,870	-5,548	2,007	7,693	4,152

As was mentioned earlier, the developer-partner in the tax-equity partnership typically has an option to acquire the remaining interest of the tax-equity investor partner at a buyout price that is the higher of the then-fair market value or that amount that provides the tax-equity investor partner its targeted AT-IRR. Table 17 includes many assumptions to compensate for underperformance of the energy generation, so the AT-IRR may be achieved either before or after the targeted flip date.

Thus, effectively what would happen is that, as the actuals of the performance are entered into the model each year, the developer and tax-equity investor-partner would concur on the results and the year-to-date AT-IRR provided to the investor. As the targeted AT-IRR is achieved, the developer would calculate the buyout value and then likely exercise its buyout of the tax-equity partner, usually as close as possible to the targeted AT-IRR.

Typically, investors in the larger and more efficient wind projects elect to claim the PTC because the PTCs generally provide a substantially greater result on a present-value basis than if the tax-equity flip partnership were to elect to claim the ITC. Those investing in smaller and less efficient wind farms and solar farms claim the ITC, which changes the financial model in that the immediate tax credit of an ITC creates a large first-year economic payback for the tax-equity investor.

Now that one understands how the economics of these transactions work, the next step is to determine how the economics should be accounted for.

Accounting: Consolidation, Equity Method, Cost Method, or Other

The first item to address when determining how to account for an investment in a tax-equity flip partnership is the determination of how that investment should be accounted for by the tax-equity investor. Recall that when accounting for an investment made into the ownership of a legal entity, the accounting methods generally familiar to most of us were (1) full consolidation of the entity, (2) the equity method of accounting for the investment, or (3) the cost method of accounting for the investment.

After the Enron scandal became public, the concept of a variable-interest entity arose and was painstakingly, continually addressed by FASB as well as by the accounting industry in general. The result of that work was ultimately incorporated into Accounting Standards Update (ASU) 2009–17, Consolidations (Topic 810). Without detailing how a conclusion is generally reached, suffice it to say that a typical, passive tax-equity investor in a flip partnership will generally *not* account for the investment using any of the aforementioned, traditional investment-consolidation reporting methods.

The first and probably most important conclusion for most investors is that they would not be required to consolidate the partnership for financial reporting purposes because they do not exercise control over that entity. Then, when attempting to apply the equity method or the cost method, the typical investor would again conclude that an alternative method is appropriate because the ownership interests will vary on a somewhat planned basis over time.

In other words, the tax-equity investor-partner does not simply make an initial investment that remains stable. Rather, it will make that initial investment, and its theoretical ownership percentage will then change based on the allocations contained in the partnership agreement. Similarly, the cost method does not consider how returns are paid to the investor. These conclusions lead most investors into the method currently followed by the relatively few tax-equity investors in the industry, most of which follow U.S. GAAP.

Hypothetical Liquidation at Book Value Accounting

For some years, entities investing (or seeking to invest) in the alternative energy financing structures struggled with the appropriate accounting for their investments. Because each investor in a tax-equity flip partnership has specific ownership accounts into which its share of profits and losses are allocated and tracked, traditional equity accounting was difficult to apply. These ownership interests also did not meet the definition of an equity instrument under ASC 320, Investments – Debt and Equity Securities.

Under U.S. GAAP, there is no formal promulgated accounting standard specifically addressing the accounting for investments in the form of a tax-equity flip partnership arrangement. However, in 2000, the Accounting Standards Executive Committee of the American Institute of Certified Public Accountants (AcSEC) issued an exposure draft of a proposed statement of position (SOP), "Accounting for Investors' Interests in Unconsolidated Real Estate Investments."

The SOP was to apply to a variety of circumstances including those that appeared consistent with the way a tax-equity flip partnership entity was structured. Bear in mind that the SOP was never issued in final form. However, it has been followed as the basis for accounting for many (if not for most) U.S. GAAP tax-equity flip partnership structure investments. The SOP introduced the approach known as the "hypothetical liquidation at book value" (HLBV) for accounting for such investments.

Under HLBV accounting, an investor arrives at its share of book income from an investment by simply determining the periodic change in its claim on the book value of the investment entity, under the theory that book value represents the fair market value of the facility in liquidation. The claim would include amounts the investor can expect to receive to achieve its targeted return, as well as (if applicable) an amount it would be required to pay back into the partnership in the event of a liquidation of the entity.

Recall that cash and tax benefits are disproportionately allocated to the tax-equity partner during the initial earning phase of the transaction. Furthermore, as discussed in the Fundamental Economics of a Tax-Equity Flip Partnership section above, a typical tax-equity partnership structure provides the tax-equity investor with certain priority rights to the cash flows and tax benefits aimed at achieving a specified target yield. Recall also that the tax-equity investor often is allocated 100% of the free cash and 99% of the tax benefits associated with the transaction during stipulated years.

The target yield is negotiated and the financial transaction is modeled using an initial financial model, which is often audited for accuracy and incorporated as part of the actual agreement. The initial financial model will include, among other items, (1) assumptions regarding the amount of tax credits allocated, (2) taxable losses allocated, (3) the assumed free cash from actual energy sales, and (4) the existence of a deficit restoration obligation agreement if applicable.

The financial models are periodically updated for the actual results and allocations as well as the new financial positions of the partners in the partnership. Thus, at any point during the investment, one should be able to examine the financial model and determine what the net assets of the partnership are, what the existing capital accounts of the partners are, and what obligations the partners may have to pay back any excess allocations. Therefore, the financial models enable the tax-equity investor to see the book basis of the partnership as well as the tax basis.

As a result of the partnership agreement, the allocation of taxable income/loss and cash distributions from the partnership is disproportionate and thus has the effect of constantly changing the tax-equity investor's capital account balance in the partnership. The capital account is akin to the tax basis of the investor in the partnership: it is equal to the contributions made into the partnership, plus taxable income/losses, less distributions.

The book capital of the partnership is calculated much like the tax capital, except that the book income or loss of the partnership is used to determine the partnership's book capital. Thus each partner in the partnership also has a book basis.

Because of the disproportionate allocation of cash distributions and income from the partnership, the ratio of the partners' capital amounts is also constantly changing. That is, the ownership percentages will change disproportionately rather than proportionately between the partners. At the end of a period, the book income cannot be properly allocated to any individual tax-equity partner based solely on its ownership percentage at that time, because such percentage is constantly changing with each distribution of cash.

For example, in a 50–50 partnership, book income is measured periodically, and each partner's share is generally affected by cash or asset distributions and book income. Usually these allocations are made evenly. When one partner adds or withdraws assets from the partnership, the aggregate assets change along with the individual ownership percentages. Thus, as Table 18 shows, if the tax-equity partner receives 95% of the cash distributions, a shift will occur between partners to the extent of that allocation.

One can see from Table 18 that when a disproportionate allocation occurs, the book income to be allocated among the partners will change from period to period.

The accounting for the partnership arrangement under a tax-equity flip partnership agreement involves an understanding not only of the book accounting but also the tax accounting and the contingent obligation of the tax-equity partners to pay back any excess distributions should the partnership be dissolved. The accounting also requires an understanding of some of the tax rules associated with partnerships.

In Table 18, partner A already has received a disproportionate allocation of cash. Therefore, should the partnership be liquidated, the excess cash distributed to partner A would need to go back into the partnership, to ensure that both partners were treated in accordance with both the partnership agreement and tax laws. Thus, in a liquidation of the partnership, partner A would be required to pay the excess distribution of $5,000 back into the partnership, and the $5,000 would then be allocated among all the partners.

The economic substance of these partnership investments relies heavily on the changing allocations of cash and tax benefits as an integral element of the partnership ownership structure. As such, it became evident that following the traditional consolidation/investment financial reporting methods (full consolidation, equity method, or cost method) for the financial reporting of the ownership interests in these partnership arrangements did not adequately represent the economic substance of the arrangements.

Therefore, as a means of determining how much book income to report, tax-equity investors within the alternative energy segment that follow U.S. GAAP have generally adopted the hypothetical liquidation at book value accounting approach that was articulated in the proposed SOP mentioned above. HLBV uses the net changes in an investor's *claims* on assets within a partnership to measure the investor's net income. The claims on the assets of the partnership are based on the combination of tax rules and the partnership agreement.

Typically, the amount of the claims on the partnership's assets is measured as the change in the investor's carrying value from one reporting period to another, assuming the investment is hypothetically liquidated at book value. The hypothetical liquidation of the partnership must follow the partnership agreement. For instance, since the partnership agreement typically calls for a targeted yield and a preferential distribution of cash proceeds to the tax-equity investor, these factors must be incorporated into the modeling of the income under the HLBV method.

The HLBV approach recognizes that when an entity is ultimately dissolved, there is a final accounting of all portions of the entity. Because the tax-equity partner is provided a theoretically guaranteed after-tax yield

Table 18. Example of How Partners' Interest Percentages Change in a Partnership

	Partner A	%	Partner B	%	Partnership	%
Opening investments	50,000	50.00%	50,000	50.00%	100,000	100.00%
Less: cash withdrawal	5,700	95.00%	(300)	5.00%	(6,000)	
Adjusted ownership	44,300	47.13%	49,700	52.87%	94,000	100.00%
Plus: $10,000 income	4,713	47.13%	5,287	52.87%	10,000	
Adjusted ending balance	49,013	47.13%	54,987	52.87%	104,000	100.00%

through the partnership agreement, the best approach is to figure out what the net assets would be if required to be distributed and then how much would have to be distributed to the tax-equity partner in order for it to achieve its targeted AT-IRR.

Needless to say, a financial model associated with both alternative energy partnership flip structures and the HLBV income recognition approach is extremely complicated — particularly when it also incorporates deficit restoration obligations (DROs) and leverage. Arguably, the most complex element of the HLBV method is calculating the allocation needed at each reporting period to provide the tax-equity investor so as to achieve its targeted yield. The challenge is that allocations of income are thus taxable and must be tax-effected to determine the after-tax yield.

Applying the HLBV method is not so difficult, provided the amount of the final allocation can be calculated, and a basic step-by-step approach can assist in applying HLBV accounting. An example of a wind tax-equity partnership structure with PTC that follows the step-by-step process for calculating the HLBV earnings is included as an appendix to this article. One will see that a number of specific calculations are required to arrive at this summary presentation. Each step and substep will be discussed below and explained. However, as the modeling itself is extremely complicated, this article cannot go into all the details.

A tax-equity financial model typically would include the specific tax capital and book balances for all partners. Given that many partners may have different tax factors to incorporate into their specific models to understand their specific yield, a further complication may occur when the individual partner incorporates those elements.

For instance, if a transaction were modeled for the partnership using only the federal statutory corporate income tax rate of 35% but the investor were also subject to state taxes, the investor would need to add the state taxes to the model to determine its actual return and actual accounting.

The steps to calculate the HLBV income follow. The appendix includes a cross-reference to each step with the explanations below.

Step 1. Calculate the partnership's pretax GAAP income and determine the partnership's GAAP capital account.

Step 2a. Calculate the partnership's taxable income. This income will obviously be different from the GAAP book income of the partnership.

Step 2b. Determine the partnership's IRC 704(b) capital account balance. This is akin to determining the overall tax "basis" of the partnership. In its simplest form, it would be the tax basis of the asset within the partnership. However, given that the partnership is akin to a business, there may be other differences between the book and tax basis of assets within the partnership.

Step 3. Determine the individual partner's IRC 704(b) capital accounts. Because each partner has a separate allocation of taxable income/loss and cash distributions that is specified within the partnership agreement, each partner will have its own separate capital account balance. The ratio of each account to the other will differ from the original percentages as a result of the disproportionate allocations.

Step 4a. Compute the taxable gain that would be recorded by the partnership based on the hypothetical liquidation of it at its book value. Because the book value should represent a reasonable valuation and fair value accounting is not being applied, the HLBV approach uses the book value as a means of establishing a hypothetical taxable gain. The gain is the difference between the hypothetical liquidation value and the tax capital accounts of the partnership determined in step 2b above.

Step 4b. Allocate the taxable gain in accordance with the specific liquidation provisions contained in the partnership agreement. It is important to read and understand exactly what those liquidation provisions call for. The liquidation provisions will be in conformity with the applicable partnership taxation rules, particularly when it comes to the DRO.

The financial model for the partnership will track the status of any DRO balance. As mentioned above, the DRO is a contingent obligation to pay back the amount of a partner's negative capital account balances to the partnership to bring the distributions into compliance with the tax rules.

A negative tax capital account balance may exist, for instance if the DRO is a limited DRO. Some tax-equity partners may desire a limited DRO so that they can limit their contingent obligation to pay back into the partnership.

If a partnership has elected bonus depreciation when it is available, the large amount of tax loss that can occur with bonus depreciation could create a large suspended tax loss for a tax-equity partner, and the partner may be reluctant to assume such a potential contingent obligation/risk.

Generally the partnership agreement will provide for a preferential distribution to the tax-equity partner after such DROs and if applicable, to other negative partnership tax capital accounts that exist, until the tax-equity partner has achieved the targeted AT-IRR.

For instance, assume that the hypothetical gain is $15 million and the tax-equity partner's interest requires a distribution of $10 million to achieve its IRR. The first $10 million of the hypothetical gain would be allocated to achieve that yield, then the balance would be allocated in accordance with the post-flip allocations — for instance, 5% to the tax-equity partner and 95% to the developer/sponsor of the transaction.

This allocation approach is typical of most tax-equity deals; however, the calculation is very complicated because it involves determining what distribution is needed and how that will be taxed to the tax-equity partner, such that the partner receives the targeted AT-IRR contained in the partnership agreement.

Step 5. To determine the individual partner's specific claim on the assets of the partnership, calculate the adjusted tax IRC 704(b) capital account balances after the hypothetical tax gain from the theoretical liquidation waterfall. This step effectively calculates the ending theoretical capital account balance that should exist and be liquidated to achieve the final targeted yield. The change in the IRC 704(b) capital accounts from the actual basis to the hypothetical liquidation then represents the HLBV income that the partner would recognize for the specific reporting period.

Summary of HLBV Approach
The approach followed by HLBV allocates the theoretically amount due from the developer partner to the tax-equity partner to achieve the targeted AT-IRR at each specific reporting period. In effect, this approach enables the tax-equity partner to recognize book gains or losses based on the commitments made by the developer partner in the partnership agreement, should the partnership be required to liquidate.

This approach is not exactly the same as merely allocating the actual book earnings of the partnership based on what has actually occurred during a year, and with the assumption that the partnership will continue on until the developer partner buys out the tax-equity partner's interest. Rather, the HLBV approach is based on what claims the tax-equity partner has on the assets and unrecorded tax elements of the partnership and then converts those claims to a book income amount so as to state the hypothetical capital account that would be liquidated.

Not only is the HLBV approach conceptually challenging to grasp but it is also difficult to apply. Thus, the HLBV approach itself has likely discouraged many potential investors from such partnerships.

Notice also, in the results presented following the HLBV approach contained in the appendix, the investor PTCs again are part of the after-tax return and included in the tax-provision line in the financial statements. That is, in the approach presented in the appendix, the PTC flows through the tax-provision line.

Even though the PTC is based on the amount of energy produced and sold (consistent somewhat with the amount of gross revenue produced) the PTC flows through the tax-provision line rather than through gross revenue. So when examining a typical HLBV accounting approach, the reporting issue of the tax credit also remains.

Exploring Alternative Accounting Approaches
1. **IFRS approach to HLBV.** Just as a final, definitive accounting standard has not been issued under U.S. GAAP, a financial standard is lacking under International Financial Reporting Standards. Even fewer IFRS reporting investors invest in tax-equity flip partnership arrangements because the tax laws governing it render that partnership structure a distinctly "U.S.-centric" product.

Although there are certainly many U.S. taxpaying subsidiaries of foreign companies that report under IFRS, few have made the investment into tax-equity partnership structures. Regarding the few that have examined it, they appear to view the targeted yield as structurally guaranteed and highly likely to be earned. In other words, given that a significant portion of the economic return is derived from tax credits and benefits that are highly likely to be realized, the view is that the targeted return is virtually assured.

Accordingly, the approach of these U.S. subsidiaries has been to apply that "guaranteed" after-tax IRR to their outstanding after-tax investment balance on a uniform basis during the life of the investment. That is, looking past the distortions found in the book balances, they examine the tax investment balance at any point in time and determine what gross book earnings they would need to achieve to obtain the targeted AT-IRR.

This approach exhibits similar variations in the earnings, because it also is tied to the tax balance of the investment and such tax balance may fluctuate widely. Also for transactions that will claim the PTC, a primary benefit is originating from the PTC, which must flow through the tax-provision line.

2. **Accounting for qualified affordable housing projects as a proxy for tax credit reporting.** Another potential approach that has been discussed, but unfortunately temporarily shelved by FASB, is the one followed for a somewhat similar type of investment as described in Accounting Standards Update 2014–01, Investments–Equity Method

and Joint Ventures (Topic 323): Accounting for Investments in Qualified Affordable Housing Projects. These investments are somewhat similar to the tax-equity flip partnership investments. The investor is allocated tax credits over a 10-year period, while the partnership itself must comply with the affordable housing tax credit rules over a 15-year period.

Under this ASU, a reporting entity may make an election to apply what is called the "proportional amortization method." Under this method the investment is amortized through the income tax expense (benefit) line in proportion to the tax credits and other tax benefits received. In other words, rather than present a book loss above the tax line, the investment is amortized below the gross income line and through the tax-provision line.

To qualify for this approach *all five* of the following conditions must be met:

1. It is *probable* that the tax credit allocable to the investor will be available.
2. The investor does not have the ability to exercise significant influence over the operating and financial policies of the limited liability entity.
3. *Substantially all the projected benefits* are from tax credits and other tax benefits (including tax losses allocated to the investor).
4. The investor's projected yield *based solely* on the cash flows from the tax credits and other tax benefits is positive.
5. The investor is a limited liability investor in a limited liability entity for both legal and tax purposes, and the investor's liability is limited to its capital investment.

If the nature of their investment meets these conditions, the investor may elect the proportional amortization method.

Previously, one of the conditions to follow this accounting for the affordable housing tax credits was that the credits were guaranteed by a creditworthy entity. That prior requirement was dropped and replaced with the notion that the tax credits would be probable.

When FASB sought comments before issuing this ASU in 2014, it asked if there might be other investments of a similar nature that possibly should also be included in this accounting.[11] ELFA responded by suggesting that the tax-equity flip partnership structure also be provided that form of accounting treatment.

In examining the discussions regarding the final position by the FASB, some FASB members believed that the proportional amortization method should be applied to all tax-credit investments that meet the conditions of the update, because that method would be suitable for all tax-credit investments that are made for the primary purpose of receiving tax credits and other tax benefits.[12] Other FASB members expressed concern about the unintended consequences. For expediency purposes, the FASB ultimately reached consensus to limit the scope to affordable housing projects.[13]

Therefore, it appears that, perhaps because of the lack of action by FASB to address this specific accounting issue, no support is available from FASB to adjust the reporting for these energy ITCs or PTCs to better reflect the economic substance of the transactions, insofar as the financial reporting of alternative energy investments is concerned.

It should also be noted that ELFA asked for FASB to include the treatment of ITC accounting within its soon-to-be-released Topic 842 on leasing, and it is not known whether FASB will address this topic in the lease accounting.

At present, most major investors in alternative energy investments tend to follow existing U.S. GAAP pertaining to the accounting for the tax credits and thus must tolerate the less-than-favorable financial reporting.

6. MANAGERIAL REPORTING CHALLENGES AND SUGGESTIONS

Managers are generally incented on pretax profits under the assumption that they cannot influence the taxes to any great extent. In these structured transactions, however, the taxes are what drive the economics of the transactions. In many cases, the accounting for the transaction may have the unintended consequence of being a disincentive to making an investment in an alternative energy investment, whether that investment is in the form of a lease or service contract or into a tax-equity flip partnership structure.

The unintended consequence results from the presence of significant income tax credits and tax benefits as a means of paying back the investment and earning an otherwise very respectable economic return. Given what is known about the various accounting issues that create this situation, one can approach the issue in a variety of ways to "solve the reporting problem." It is up to the potential investors to recognize the reporting challenges and determine whether they can solve the challenges to make these investments.

As this article shows, many different types of investments could be made in the alternative energy sector. Each investor may have different tolerances for the types of investments that it might consider. Some investors may prefer the simplicity of a lease compared to the risk of a service contract, while others may not desire to invest in a lease or power purchase agreement transaction with a tenor of 20 to 30 years. Still others may prefer the relatively short-term nature of tax-equity flip partnerships, which allow an investor to be in and out of an investment within 6 to 10 years or so, while others avoid them due to the complexity and challenging financial reporting.

With the focus of this article on financial reporting issues, we proceed to some possible approaches to mitigate the challenges.

Separate Reporting Unit

Some companies place their alternative energy financing businesses into a separately reporting business unit that creates its own separate financial metrics for measuring the business. They might also do this with their other tax-oriented types of investments that exhibit somewhat unusual financial reporting results. In this manner, the business can be reviewed by management with the after-tax economic results in mind rather than the GAAP accounting results.

This approach can work if upper management understands the adjusted metrics and agrees with the economic approach. Yet this approach is acceptable only insofar as the pretax book losses do not become a material component of the overall reporting entity. These structures can be seen, for instance, within several banks with such stand-alone business units.

This approach may work for all forms of investments, including those where the returns are largely driven by PTCs rather than ITCs, because the entire return would be isolated into a separate reporting entity.

Management Reporting Adjustments

Some financial investors in transactions that provide unusual pretax reporting results accept the pretax net income losses for GAAP reporting purposes, but they modify the management reporting through adjustments to the internal financial reporting results. This is done through a normalization procedure that can also be found in the tax-exempt financing area, where we have seen that for reporting purposes, the pretax tax-exempt income is grossed up to a pretax taxable equivalent.

With respect to alternative energy investments, one way to adjust the management reporting results is to move the tax credits from the tax-provision line to the pretax net income line. Alternatively, the tax credits can be grossed up and moved into the gross revenue line for internal management reporting purposes.

Simply moving the tax credits to above the tax-provision line has been illustrated in tables 12 and 13 above. The problem noted in those analyses is that the return still emanates from the tax credit and the tax benefit in the tax provision.

However following a gross-up approach adjusts the financial results to present a result that appears more akin to what is otherwise expected from a typical taxable investment. For example, assuming a 35% tax rate, a $30 ITC would be grossed up to $46, such that after deducting hypothetical taxes of $16 ($46 × 35%), the net cash provided is the original $30. This can even be accomplished using special reporting-only accounts to which actual journal entries could be made, as follows:

	Debit	Credit
Grossed-up revenue		46.00
Provision for taxes on grossed-up revenue	16.00	
Taxes payable	30.00	

In this fashion, the financial benefit of the ITC is recognized as a grossed-up revenue item to enable management to review the transactions in a manner more consistent with what it usually reviews. Table 19 presents an example of grossing up the tax credit to a pretax equivalent.

In this illustration, the resultant income statement appears more consistent with an income statement of a typical operating lease. Obviously, keeping track of the gross-up and the hypothetical taxes on the gross-up presents an accounting challenge. This approach may be used for internal tracking purposes and in fact is used by some entities with substantial tax-exempt

Table 19. Operating Lease Using Grossed-up ITC as Revenue (millions of dollars)

	Totals	Year 1	Year 2	Year 3	Year 4	Years 5–20
Revenues	72.00	3.60	3.60	3.60	3.60	57.60
Grossed-up revenues (ITC)	46.00	2.30	2.30	2.30	2.30	36.80
Total revenues	118.00	5.90	5.90	5.90	5.90	94.40
Depreciation	(100.00)	(5.00)	(5.00)	(5.00)	(5.00)	(80.00)
Gross profit/(loss)	18.00	0.90	0.90	0.90	0.90	14.40
Tax provision						
Based on book income	9.80	0.49	0.49	0.49	0.49	7.84
Based on nontaxable income	(16.00)	(0.80)	(0.80)	(0.80)	(0.80)	(12.80)
Total tax provision	(6.20)	(0.31)	(0.31)	(0.31)	(0.31)	(4.96)
Net income after taxes	11.80	0.59	0.59	0.59	0.59	9.44

income within their investment portfolio.

This approach may work for all forms of transactions: again, the adjustment would be made regardless of whether the investment generates ITC or PTC.

Exception to GAAP Reporting

As indicated in the ELFA comment letter on the new leasing standards, the AICPA "Audits of Banks" guidelines have noted that for some time, some banks have been following alternatives to published GAAP pertaining to the reporting of some large tax credits from certain investments. These banks have apparently done two things: (1) used the deferred tax credits from ITCs as an offset against the investment within the asset section of the balance sheet rather than as a deferred liability within the tax liability section of the balance sheet, and (2) recognized the deferred ITC credit amortization as a nontaxable element within pretax income — either as a revenue item or as an offset to depreciation.

Reporting the deferred tax credit as a reduction of the investment recognizes that the ITC is acting to reduce the cost of the asset and is consistent with accounting for grants found under IFRS as well as the accounting for the U.S. Treasury Section1603 grants when they were available. As we already discussed, when the 1603 grants were available, U.S. GAAP did not have a clear approach to accounting for them. At that time a few of the Big 4 accounting firms analogized the 1603 accounting to grant accounting as was outlined within IFRS.

Another alternative exception to the GAAP approach may be to (1) analogize the financial reporting to that found under the affordable housing tax credit investments and (2) follow an approach similar to that for those alternative energy investments that rely heavily on the tax credits.

Under the affordable housing tax credit investment approach, a portion of the investment equal to the deferred ITC amortization would be amortized through the tax-provision line to offset the ITC amortization, thus effectively moving that portion of the investment write-off through the tax-provision line. Essentially, this approach is stating that a portion of the investment was paid for through the tax credits.

It should be noted, however, that any time reporting adjustments are made to the tax-provision line, such adjustments would have to be explained in the tax-provision footnotes, since the adjustments to the tax provision affect the effective tax rate of the entity.

The argument for adjusting the reporting of the PTC may also have some merit. The PTC is claimed based on actual production; thus, if a facility does not produce any energy, there would be no PTCs, whereas if it produces much energy, there would be larger PTCs. The PTC thus is more akin to a revenue subsidy.

Perhaps the accounting for the affordable housing tax credits discussed above, combined with the reference in the PwC ARM regarding some banks' treatment of larger tax credits, together would provide an analogous suggestion on an alternative financial reporting approach. That is, the financial reporting can be adjusted by either (1) removing the PTC out of the tax-provision line and moving it into the revenue line and considering it a tax-exempt form of revenue or (2) by writing off an equal portion of the investment as an offset against the PTC within the tax-provision line. With either approach, perhaps more investors would find such projects more investment worthy.

In either case, the GAAP reporting issue largely relates to the accounting for the tax credits: whether traditional GAAP should be followed or whether one can follow some other reporting approach that is meaningful and supportable.

7. CONCLUSION

Just as Congress creates incentives for investing in specific types of alternative energy projects (as well as other targeted types of investments for that matter), so, too, the financial reporting should be reflective of the nature of the investment, wherein a good portion of the return is actually tax driven with nominal investment risk. The IFRS approach takes a step in that direction and is supported somewhat by ASU 2014–01, which incorporates the low-risk nature of tax benefits in many investments as a means of recognizing the tax-benefit driven return from such projects.

At the end of the day, the objective of any financial reporting is to report the results in a manner that is clear and not misleading. Sometimes following strict U.S. GAAP rules will provide the GAAP-compliant results — but not a result that would have been reached had one followed a more principles-based approach.

As U.S. GAAP moves to a more principles-based approach to its reporting, U.S. financial reporting entities may need to first look to what their reporting objective should be and then whether existing GAAP adequately addresses that objective. It is indeed challenging to offer up an alternative approach to the financial reporting when many parties, including the auditors of the reporting entity, may be reluctant or unwilling to accept anything other than what is contained in current accounting standards. ELFA anticipates working with member companies in the alternative energy arena to confront this challenge.

Appendix. Tax-Equity Partnership Hypothetical Liquidation at Book Value Example

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
Step 1. Determine partnership book income and GAAP capital. (Assume $200 million starting basis.)										
Revenues	9,690	19,525	19,964	20,413	20,873	21,342	21,823	22,314	22,816	23,329
Operating expenses	-3,523	-7,116	-7,305	-7,498	-7,697	-7,901	-8,111	-8,325	-8546	-8,773
Book depreciation	-5,041	-10,000	-10,000	-10,000	-10,000	-10,000	-10,000	-10,000	-10,000	-10,000
Book income	**1,125**	**2,409**	**2,659**	**2,915**	**3,176**	**3,441**	**3,712**	**3,988**	**4,270**	**4,556**
Cash available for distribution	4,560	12,372	12,622	12,877	13,137	13,402	13,672	13,947	14,227	14,513
Assets book value (hypothetical liquidation value)	196,565	186,601	176,638	166,676	156,714	146,754	136,794	126,836	116,878	106,921
Step 2. Determine hypothetical gain by comparing book value to tax basis.										
Assets book value (above)	196,565	186,601	176,638	166,676	156,714	146,754	136,794	126,836	116,878	106,921
Adjusted partnership tax basis (2a, b & c)	179,148	111,080	69,963	45,045	23,156	7,528	7,659	7,792	7,927	8,065
Hypothetical gain (2d)	**17,417**	**75,521**	**106,675**	**121,630**	**133,558**	**139,226**	**129,136**	**119,044**	**108,950**	**98,856**
Step 3. Allocate hypothetical gain to tax-equity investor.										
Hypothetical gain	17,417	75,521	106,675	121,630	133,558	139,226	129,136	119,044	108,950	98,856
Allocated to achieve target yield	17,309	72,397	98,874	107,404	112,031	109,167	89,475	67,372	43,222	16,281
Post-target allocation	378	3,125	7,801	14,225	21,527	30,059	39,661	51,672	65,728	82,572
Investor gain allocation										
Allocated to achieve target yield	17,039	72,397	98,874	107,404	112,031	109,167	89,475	67,372	43,222	16,281
Post-target allocation	19	156	390	711	1,076	1,503	1,983	2,584	3,286	4,129
Sponsor gain allocation										
Pre-flip allocations	0	0	0	0	0	0	0	0	0	0
Post-target allocation	359	2,969	7,411	13,514	20,451	28,556	37,678	49,088	62,442	78,446
Step 4. Calculate investor tax capital account change.										
Capital account balance	99,996	44,857	16,648	4,729	-3,937	-6,142	-6,149	-6,156	-6,164	-6,173
Allocated to achieve target yield	17,039	72,397	98,874	107,404	112,031	109,167	89,475	67,372	43,222	16,281
Post-target allocation	19	156	390	711	1,076	1,503	1,983	2,584	3,286	4,129
Total liquidation proceeds to investor	117,054	117,410	115,911	112,844	109,170	104,528	85,309	63,799	40,345	14,237
Investment carrying value	**117,054**	**117,410**	**115,911**	**112,844**	**109,170**	**104,528**	**85,309**	**63,799**	**40,345**	**14,237**
Cash distributions	0	0	0	0	0	0	13,672	13,947	14,227	14,513
Pretax book income (– loss)	**132**	**-2,680**	**-2,860**	**-3,400**	**-4,261**	**-4,690**	**-4,324**	**-6,340**	**-8,011**	**-10,401**
Step 5. Calculate investor after-tax net income.										
Pretax book income	132	-2,680	-2,860	-3,400	-4,261	-4,690	-4,324	-6,340	-8,011	-10,401
After-tax book income (40%)	79	-1,608	-1,716	-2,040	-2,557	-2,814	-2,595	-3,804	-4,807	-6,240
Investor PTCs	3,816	7,979	7,979	8,326	8,326	8,672	8,672	9,019	9,019	9,366
After-tax net income	**3,895**	**6,371**	**6,262**	**6,286**	**5,769**	**5,859**	**6,078**	**5,215**	**4,213**	**3,126**

Appendix. Tax-Equity Partnership Hypothetical Liquidation at Book Value Example (continued)

	Year 11	Year 12	Year 13	Year 14	Year 15	Year 16	Year 17	Year 18	Year 19	Year 20
Step 1. Determine partnership book income and GAAP capital. (Assume $200 million starting basis.)										
Revenues	23,854	24,391	24,939	25,501	26,074	26,661	27,261	27,874	28,501	23,329
Operating expenses	-9,005	-9,244	-9,489	-9,840	-9,998	-10,263	-10,535	-10,814	-11,101	-11,395
Book depreciation	-10,000	-10,000	-10,000	-10,000	-10,000	-10,000	-10,000	-10,000	-10,000	-10,000
Book income	**4,849**	**5,147**	**5,451**	**5,760**	**6,076**	**6,398**	**6,726**	**7,060**	**7,400**	**7,748**
Cash available for distribution	14,805	15,102	15,405	15,713	16,028	16,348	16,675	17,008	17,348	17,694
Assets book value (hypothetical liquidation value)	**96,965**	**87,010**	**77,056**	**67,104**	**57,152**	**47,201**	**37,252**	**27,303**	**17,356**	**7,410**
Step 2. Determine hypothetical gain by comparing book value to tax basis.										
Assets book value (above)	96,965	87,010	77,056	67,104	57,152	47,201	37,252	27,303	17,356	7,410
Adjusted partnership Tax basis	7,751	6,967	6,183	5,401	4,619	4,011	3,822	3,634	3,448	2,451
Hypothetical gain	**89,214**	**80,044**	**70,873**	**61,703**	**52,533**	**43,190**	**33,430**	**23,669**	**13,908**	**4,959**
Step 3. Allocate hypothetical gain to tax-equity investor.										
Hypothetical gain	89,214	80,044	70,873	61,703	52,533	43,190	33,430	23,669	13,908	4,959
Allocated to achieve target yield	6,177	-	-	-	-	-	-	-	-	-
Post-target allocation	83,036	80,044	70,873	61,703	52,533	43,190	33,430	23,669	13,908	4,959
Investor gain allocation										
Allocated to achieve target yield	6,177	-	-	-	-	-	-	-	-	-
Post-target allocation	4,152	4,002	3,544	3,085	2,627	2,160	1,671	1,183	695	248
Sponsor gain allocation										
Pre-flip allocations	-	-	-	-	-	-	-	-	-	-
Post-target allocation	78,885	76,041	67,330	58,618	49,906	41,031	31,758	22,485	13,213	4,711
Step 4. Calculate investor tax capital account change.										
Capital account balance	-6,177	-	-	-	-	-	-	-	-	-
Allocated to achieve target yield	6,177	-	-	-	-	-	-	-	-	-
Post-target allocation	4,152	4,002	3,544	3,085	2,627	2,160	1,671	1,183	695	248
Total liquidation proceeds to investor	4,152	4,002	3,544	3,085	2,627	2,160	1,671	1,183	695	248
Investment carrying value	**4,152**	**4,002**	**3,544**	**3,085**	**2,627**	**2,160**	**1,671**	**1,183**	**695**	**248**
Cash distributions	7,693	755	770	786	801	814	834	850	867	885
Pretax book income (– loss)	**-1,932**	**1,451**	**312**	**327**	**343**	**350**	**346**	**362**	**379**	**437**
Step 5. Calculate investor after-tax net income.										
Pretax book income	-1,935	1,451	312	327	343	350	346	362	379	437
After-tax book income (40%)	-1,159	871	187	196	206	210	207	217	228	262
Investor PTCs	2,007	-	-	-	-	-	-	-	-	-
After-tax net income	**848**	**871**	**187**	**196**	**206**	**210**	**207**	**217**	**228**	**262**

Endnotes

1. The Energy Policy Act of 1992 (P.L.102-486)

2. U.S. Energy Information Administration website; /http://www.eia.gov/tools/faqs/faq.cfm?id=92&t=4

3. *Why the ITC Matters for Offshore Wind*, by Constance McDaniel Wymann, North American Windpower magazine, Vol 10, Number 6, July 2013

4. IRC Section 168(g)(1)(B)

5. U.S. Treasury § 1.704-1(b)(2)(ii)(d).

6.U.S. Treasury § 1.704-1(b)(2)(ii)(c).

7. A Private Letter Ruling ("PLR") is a determination provided by the IRS regarding the tax treatment of a specific set of facts in response to a taxpayers request for guidance. A PLR is applicable for that situation only and is not valid for other situations.

8. Emphasis added.

9. Comment added.

10. *Id.*

11. ASU 2014-1 BC 9.

12. ASU 2014-1 BC 10.

13. ASU 2014-1 BC 10.

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Disclaimer

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The Impending Impact of Section 1071 and Creeping Consumerism on Equipment Finance

By John C. Redding, Moorari K. Shah, Kathleen C. Ryan, and Mitchell M. Grod

Section 1071 of the Dodd-Frank Act goes beyond consumer lending to regulate business credit. It broadly applies to any entity engaged in financial activity, which may include commercial lessors once the Consumer Financial Protection Bureau publishes proposed regulations scheduled for late 2016. Will you be ready?

One of the lesser known provisions appearing in Title 10 of the 2010 Dodd-Frank Act (DFA) is Section 1071, which imposes data collection requirements similar to those set forth in the Home Mortgage Disclosure Act (HMDA) and Regulation C.[1] However, unlike many DFA requirements that are limited in application to consumer lending, Section 1071 extends to business lending and broadly applies to any entity engaged in financial activity.[2]

As a result, equipment finance companies can expect to incur significant costs and implement extensive operational changes to their application and underwriting processes in the coming years, under the watchful eye of the Consumer Financial Protection Bureau (CFPB).[3]

In particular, Section 1071 amends the Equal Credit Opportunity Act (ECOA) to require financial institutions receiving a business loan application to inquire whether or not:

- the business is a women-owned, minority-owned, or small business; and
- such application is in response to a solicitation by the financial institution.[4]

In addition, financial institutions must collect and maintain a record separate from the application, clearly and conspicuously disclosing the following information:

- The number of the application and the date on which the application was received
- The type and purpose of the loan or other credit being applied for
- The amount of the credit or credit limit applied for, and the amount of the credit transaction or the credit limit approved for such applicant
- The type of action taken with respect to such application, and the date of such action
- The census tract in which is located the principal place of business of the women-owned, minority-owned, or small business loan applicant
- The gross annual revenue of the business in the last fiscal year of the women-owned, minority-owned, or small business loan applicant, preceding the date of the application
- The race, sex, and ethnicity of the principal owners of the business
- Any additional data that the CFPB determines would aid in fulfilling the purposes of this section[5]

All information compiled through this inquiry must be segregated from the underwriting process, and it cannot otherwise include any personally identifiable information of the applicant.[6] Specifically, the data must be segregated from the loan application itself and shielded from access by anyone within the lending organization with lending authority over the application.[7] The collected data must be reported annually to the CFPB, which will make the information "available to any member of the public, upon request."[8]

POTENTIAL APPLICATION TO TRUE LEASES

Consistent with ECOA, Section 1071 applies to all "credit."[9] Accordingly, in addition to standard purchase-money loans and installment credit sales, equipment finance companies may be called on to collect data in connection with conditional sales or "purchase leases" that contain a bargain

Collecting only demographic information, as set forth in Section 1071, appears to assume a single conclusion: that all credit decisions are based solely on demographics.

purchase option.[10] However, it remains an open question as to whether the CFPB will require data collection for "true leases," pursuant to which the lessor generally retains the ownership interest and residual value risk of the leased property.[11]

A troubling development in this regard is the CFPB's expansive inclusion of automobile leases in the issuance of the final rule defining larger participants of the automobile financing market.[12] In particular, the CFPB went to great lengths to explain that — although prudential regulators have reasoned that residual value percentages and actual transfer of ownership are key factors in determining whether a lease is the "functional equivalent" of a loan — the CFPB does not share this view.[13] Instead, the CFPB interprets the phrase "functional equivalent of purchase finance arrangements" set forth in the DFA to include all leases in which the lessee has the option to purchase the leased property at the end of the lease term for a predetermined amount, regardless of whether the option is ever exercised.[14]

Conceivably, then, the CFPB's "functionally equivalent" rationale may extend data-collection requirements to true leases, which typically permit the lessee to purchase equipment at fair market values to be determined at the end of the lease term. In any event, to the extent a lessee opts to exercise a purchase option at the end of the lease term and finances the buyout amount, this subsequent transaction would be considered an extension of credit under ECOA, and thus subject to Section 1071's data-collection requirements.

CREEPING CONSUMERISM

On its face, Section 1071 appears to be out of place. In particular, one must question why a commercial lending data-collection requirement is included in a statute designed to address consumer credit issues and is to be enforced by a newly established government agency specifically dedicated to consumer protection. The stated purpose of Section 1071 fails to provide any particular insight to help answer this fundamental question, to wit,

> … [t]he purpose of this section is to facilitate enforcement of fair lending laws and enable communities, governmental entities, and creditors to identify business and community development needs and opportunities of women-owned, minority-owned, and small businesses.[15]

Presumably, then, the ultimate objective of the data collection is to motivate financial institutions to increase their lending to meet the credit needs of small businesses and neighborhoods in a nondiscriminatory manner — a noble cause unlikely to be met with any significant opposition but seemingly unrelated to consumer lending.

To be sure, ECOA has always applied to commercial credit transactions, and equipment finance companies are generally expected to have policies and procedures in place to avoid discrimination on a prohibited basis. Moreover, these same finance companies are expected to provide an appropriate adverse action notice and, in the case of certain business credit applicants, a statement providing the reasons for the denial as required under Regulation B.[16]

Nonetheless, setting aside the scope creep of consumer protection laws and regulations into commercial enterprises, there also appears to be a disconnect between fulfilling the purpose of Section 1071 and ECOA generally, and the data to be collected to fulfill that purpose. After all, one might expect to collect information regarding credit and collateral quality to understand the effects of credit practices on minority-owned, women-owned, and small businesses.

Put bluntly, collecting only demographic information, as set forth in Section 1071, appears to assume a single conclusion: that all credit decisions are based solely on demographics. In fact, this was precisely what occurred when HMDA data was first collected and made public in 1991, leading to accusations of discrimination that were largely unsupported by disciplined statistical analysis.[17]

As a result, although the regulations for Section 1071 have yet to be drafted, the fear of unwarranted reprisals based on partial data sets and uncontrolled variables has many equipment finance companies justifiably worried and others calling for a repeal of the provision altogether.[18]

PLANNING AHEAD

Although no specific date for the proposed regulations has been established, the CFPB's fall 2015 rulemaking agenda indicates that the regulations are currently in the "pre-rule stage" — the CFPB's signal that it has initiated research and outreach to support a forthcoming rule.[19] The process will continue through, at least, fall 2016.[20] Thereafter, the regulations will proceed through the formal rulemaking process, suggesting that Section 1071 will not become fully effective until the first half of 2017 at the earliest.

Despite recent calls for immediate action by members of

Congress,[21] a more realistic scenario for the regulations to take effect may in fact be the latter half of 2018 or later, based in part on the fact the CFPB set January 1, 2018, as the effective date of the recently updated HMDA data collection rules — a period more than two years after the rules were finalized.[22]

Parallels to HDMA

It remains unclear precisely how the CFPB intends to implement Section 1071 through the upcoming regulations. Nevertheless, the industry may be able to draw some conclusions from HMDA and Regulation C. In fact, when addressing the issue of developing regulations to implement Section 1071, the CFPB referenced HMDA as an analogous regime.[23] Further, the CFPB rulemaking agenda indicates the CFPB will use recently promulgated HMDA regulations as the foundation for Section 1071 guidance.[24]

Of particular importance, HMDA and its implementing regulation, Regulation C, prescribe detailed guidance and supporting materials that establish:

- Consistent definitions of terms
- Procedures for requesting information regarding race, ethnicity, and gender
- Information data fields to be collected
- Data coding protocols
- Procedures for report formatting and transmittal[25]

Operations Overhaul

As was true for the mortgage industry, equipment finance companies can expect a significant learning curve to understand and apply the forthcoming Section 1071 regulations. For example, many equipment financers may not currently require a traditional written application for commercial loans. Without a formal application process, it will necessarily be more difficult to identify the precise date upon which a commercial customer "applied" for or requested credit.

This uncertainty may, in turn, lead a skeptical regulator to question whether the required data was collected accurately or from all "applicants." In addition, these new data-collection requirements will undoubtedly require some level of overhaul to existing underwriting and recordkeeping processes, as well as data storage and other IT systems and processes, including the potential need to secure additional resources and personnel to implement the new procedural framework.

Furthermore, with respect to vendor finance programs established to entice manufacturers, brokers, and dealers with commission and profit-sharing opportunities, equipment leasing and finance companies will need to develop clear procedures and provide training to collect Section 1071 data from these third parties. This added layer of collection inevitably will lead to additional challenges around the accuracy and completeness of collected data.

Policy Considerations

In addition to potential process challenges, Section 1071 presents public policy concerns, such as striking an acceptable balance between the gathering and maintaining of this new data with the need for privacy of the customer and maintaining anonymity in the loan process.

For instance, finance companies typically do not inquire about the race, color, religion, national origin, or sex of an applicant in an effort to ensure compliance with ECOA's standing prohibition against discrimination in any aspect of the credit process. Adhering to this restriction ostensibly mitigates the risk of claims of discrimination in the underwriting and loan decision processes.

Section 1071, however, arguably makes finance companies more susceptible to attack on the grounds of discrimination, because their customers may seek to assert that finance companies took into account the very information they were prohibited from considering when making their credit or pricing decision. Although Section 1071 prohibits underwriters or other officers or employees from having access to the collected data,[26] it remains unclear how the practical implications and implementation of this rule will unfold.

Section 1071 may also adversely impact competition by mandating publication of pricing information. Specifically, equipment leasing and finance companies will be required to disclose transaction-level data, including information related to approved and declined loans, credit terms, and certain aspects of customer credit profiles. The industry has expressed concern that releasing such detailed data could enable competitors to reverse-engineer the data to identify proprietary trade information such as lending matrices and investors.[27]

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In addition, the possibility of linking Section 1071 data with information contained in publicly available UCC financing statements may further disrupt the competitive landscape for equipment leasing.

Nonetheless, and as was the case in the mortgage industry with the implementation of HMDA, it is prudent for all equipment finance companies to begin planning for how to collect and store this new data and meet the reporting requirements that are likely to be implemented once the regulations become effective.

> More pressing than the cost and public policy concerns are the potential implications of how the CFPB intends to process data received under Section 1071 and what conclusions regulators may draw from the data.

FAIR LENDING AND DISPARATE IMPACT

More pressing than the cost and public policy concerns outlined above are the potential implications of how the CFPB intends to process data received under Section 1071 and what conclusions regulators may draw from the data. As previously observed in the residential mortgage industry — and more recently in the auto finance industry — the theory of disparate impact can have profound effects on both the way lenders conduct business and the types of credit products they offer.

Divided Supreme Court

Currently, where race, gender, and ethnicity information is available, such as the mortgage market based on HMDA data, the CFPB seeks to determine whether potential disparities exist applying an "effects test" to assert disparate impact claims. As confirmed by the U.S. Supreme Court in *Texas Department of Housing and Community Affairs v. Inclusive Communities Project Inc.*, in the context of the Fair Housing Act, establishment of a prima facie case under disparate impact requires:

- First, the plaintiff (in this instance the CFPB) must show that a specific and facially neutral lending policy or practice has a disproportionately adverse impact on a protected class group and that the policy caused that impact.[28]
- Next, the burden shifts to the financial institution to demonstrate a nondiscriminatory business rationale for the policy or procedure.[29]
- Finally, to overcome the business justification, the CFPB must demonstrate there is an available alternative practice that has less discriminatory effect but still achieves the business objective advanced by the financial institution.[30]

The cognizability of disparate impact claims has been upheld by the U.S. Supreme Court in the context of employment discrimination under Title VII of the Civil Rights Act, the Age Discrimination in Employment Act, and the Fair Housing Act (FHA). Most recently, the Supreme Court upheld the disparate impact theory under the FHA in *Texas Department of Housing and Community Affairs v. Inclusive Communities Project Inc*. This 5–4 decision narrowly affirmed the holding of the Court of Appeals for the Fifth Circuit regarding the cognizability of such claims under the Fair Housing Act in light of the "effects" language contained therein.[31]

ECOA Distinctions

Notwithstanding the holding of *Inclusive Communities*, finance companies still have a number of arguments that the Court's analysis does not apply to ECOA, given the material differences between the text and history of the FHA and ECOA. First, the court based its textual arguments on the use of "otherwise make unavailable" in Section 804 of the FHA — a section that applies to the sale and rental of housing but not to lending.[32] The court stated that this effects-based language "is of central importance" to its analysis.[33] But ECOA contains no similar effects-based language.

Second, the court's analysis of the FHA's amendment history is inapplicable to ECOA. The court focused principally on three provisions that it characterized as "exemptions" from disparate-impact liability, and it concluded that such exemptions made sense only if Congress were acknowledging the validity of disparate impact claims.[34] But ECOA contains no similar "exemptions" from disparate-impact liability that might otherwise lead to the conclusion that disparate impact is cognizable under ECOA.

Whatever similarities may be perceived to exist between the purpose of the FHA and ECOA, the material textual and historical differences weigh heavily against treating the two statutes the same for disparate-impact purposes. Nonetheless, this recent decision likely will embolden the CFPB, state regulators, and private litigants to continue pursuing fines, penalties, and damages based on disparate impact predicated entirely on demographic data.

POTENTIAL IMPLICATIONS FOR ALTERNATIVE FINANCE COMPANIES

Although the application of disparate-impact analysis has presented challenges in consumer lending, its application to commercial lending may have an even more profound impact given differences in the lending process.

For example, consumer loan programs and pricing are often homogenous, allowing finance companies to apply a standard matrix to determine pricing and loan program parameters based on objective factors such as a borrower's credit score or a loan-to-value ratio of the asset.

Conversely, many commercial borrowers lack credit scores that are analogous to those in the consumer credit market for the purposes of setting standardized rates and loan program parameters. Further, commercial lenders are not necessarily wedded to standardized loan matrices. Instead they may structure each transaction based on its perceived risk and complexities.

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Take, for example, the recent rise of alternative finance companies, which have been credited with filling the void in small business lending that many big banks have largely shunned in recent years due to subpar returns.[35] The success of these nonbank credit sources has been substantially driven by a big-data approach to underwriting that heavily emphasizes automation and machine-learning algorithms. These are constantly updated based on the absorption of bits and bytes of information from nontraditional data sources to deliver a credit decision in nanoseconds.[36] When recently asked the basis for its credit decisions, the CEO of one of these popular, alternative-finance startups quipped, "I wouldn't know. . . . It's math, not magic."[37]

Exposing financial institutions to potential liability based on surface-level statistical analyses without meaningful controls for other relevant factors threatens to hinder the ability of finance companies to create innovative products and offer affordable access to commercial credit to a wide spectrum of business customers.

As a result, many lenders may simply choose not to offer certain customized loan products or to offer fewer of them, thereby depriving responsible borrowers of otherwise available products and undermining the very intent of Section 1071 to increase the amount of credit available to women-owned, minority-owned, and small businesses. Worse yet, the resulting decrease in competition may have the unintended effect of increasing costs to commercial borrowers.

NOT JUST LARGE BANKS AND NOT JUST THE CFPB

Some may believe that the DFA is primarily intended to oversee the activities of large banks and certain nonbank institutions deemed to be larger participants in certain industries, but Section 1071 is explicitly different. It applies to all "financial institutions."[38] The term "financial institution" means any partnership, company, corporation, association (incorporated or unincorporated), trust, estate, cooperative organization, or other entity that engages in any financial activity.[39]

Further, the implementation of Section 1071 will expand certain CFPB enforcement powers to commercial credit. As seen in the mortgage and auto finance industry, a CFPB presence tends to embolden state regulators to become more active in enforcement.[40] In addition, state attorneys general may invoke authority under Section 1042 of the DFA to bring a civil action for violations.[41]

As a result, once Section 1071 becomes effective through its implementing regulations, the commercial finance industry should be prepared to experience a more active regulatory environment, including more collaboration among states and federal agencies, increased sharing of information between these regulatory bodies, and in some cases, joint enforcement actions.

KEY TAKEAWAYS AND NEXT STEPS

It is imperative that equipment finance companies take a proactive approach both to prepare their infrastructure and processes to gather, store, and report Section 1071 data, and to mitigate fair lending risk. Specifically, equipment lessors and finance companies may wish to consider the following:

- Review, assess, and revise current commercial credit policies and procedures to avoid claims of discrimination and disparate impact. These policies and procedures may be enhanced to include detailed fair lending sections, inclusive of a clear statement of the company's fair lending policy consistent with best practices and regulatory expectations. In addition, the policies should explore specific program parameters, including limitations on discretion with respect to rates, documentation, and exceptions in the lending process, as well as internal auditing roles and responsibilities to monitor for and address potential issues.
- Assess current origination, underwriting, and loan-processing systems to ensure Section 1071 and its implementing regulations can be properly implemented once established. Such an assessment might include whether systems are capable of gathering the relevant data, and storing the information in a readily accessible format. While ensuring that the information is not accessible to anyone who is involved in making a decision about the application, companies also should be retaining these records for the required three years.[42]
- Clearly define the commencement of the application process, supported by a written record where practicable. Although such an effort may be met with resistance by some commercial customers, this procedural change may also improve overall operational efficiency. Similarly, lenders can consider compil-

ing a detailed commercial loan origination workflow, from inquiry through booking to the lender's systems and record retention and reporting.

- Create a detailed complaint-monitoring strategy and proactively address customers' issues and questions. Doing so may also allow equipment finance companies to identify any possible systemic weaknesses to be addressed in advance of the Section 1071 regulations taking effect. Such an approach can also help mitigate the risk of a disgruntled customer complaining to a regulator or plaintiff's attorney. Moreover, the CFPB actively monitors and publishes customer complaints, based on a pattern of complaints.
- Assess resources to ensure all essential functions can be accomplished in a timely and compliant fashion. This may include areas such as recordkeeping, data entry, quality control, regulatory reporting, and data analysis. Similarly, consider providing appropriate training regarding these new requirements and any resulting process changes to relevant employees on a periodic basis.

The ultimate implementation of the foregoing steps will be a large undertaking. As such, equipment lessors and finance companies should consider identifying a point person with the time, decisionmaking authority, experience, and willingness to learn the new regulations.

CONCLUSION

Although Section 1071 has resulted in limited activity since first enacted in 2011, calls for far more attention are being made. In addition, the CFPB has begun the process to issue proposed regulations in 2016. These requirements are likely to disrupt the commercial credit industry, just as other DFA sections have disrupted the mortgage and auto lending industries. Some can be anticipated and others are likely to surprise. Implementation will almost certainly be challenging, time-consuming, and costly. Will you be ready?

Endnotes

1. 15 U.S.C. § 1691c–2. *See also* 12 U.S.C. § 2801, *et seq.;* 12 C.F.R. § 1003.1 et seq.

2. 15 U.S.C. § 1691c–2(b), (h). Congress did not define "financial activity" in Section 1071, but instead, left this broad term to the CFPB to define. It is likely that the bureau will define the term expansively to ensure that the resulting data are robust and useful to the bureau.

3. Although Section 1071 technically became effective on July 21, 2011, the CFPB has indicated that data-collection requirements will not take effect until the CFPB issues necessary implementing regulations regarding (1) appropriate procedures, (2) information safeguards, and (3) privacy protections. Section 1071 of the Dodd-Frank Act, CFPB General Counsel Letter, April 11, 2011 (http://files.consumerfinance.gov/f/2011/04/GC-letter-re-1071.pdf). As of July 15, 2015, CFPB enforcement activity has resulted in approximately $10.1 billion in fines and penalties; $2.6 billion in restitution to consumers; and $7.5 billion in principal reductions, canceled debt, and other consumer relief. Consumer Financial Protection Bureau: Enforcing Consumer Protection Laws, at: http://files.consumerfinance.gov/f/201507_cfpb_enforcing-consumer-protection-laws.pdf.

4. 15 U.S.C. § 1691c–2(b)(1). Like HMDA, an applicant may refuse to provide any information requested. 15 U.S.C. § 1691c–2(c). "Small business" means one that is independently owned and operated and that is not dominant in its field of operation, provided that, notwithstanding any other provision of law, an agricultural enterprise shall be deemed to be a small business concern if it (including its affiliates) has annual receipts not in excess of $750,000. 15 U.S.C. § 1691c–2(h)(2); 15 U.S.C. § 632.

5. *5* 15 U.S.C. § 1691c–2(e). Note that, like Section 1071, HMDA also grants the CFPB authority to add other data elements to serve the statutory purposes. See 15 U.S.C. §2803(b)(5)(D), (6)(F). The CFPB invoked this authority in its October 2015 release of the new Regulation C by adding several data points for, among other things, the borrower's debt-to-income ratio, the combined-loan-to-value ratio, and the results of an automated underwriting system used to evaluate the application. 80 FR 66127, 66311 (12 C.F.R. § 1003.4(a)(23), (24), (35) [effective Jan. 1, 2018]. Similarly, the commercial lending industry should expect the CFPB to take advantage of its authority under Section 1071 and include additional data reporting elements when issuing implementing regulations.

6. *Id.;* 15 U.S.C. § 1691c–2(d)(1).

7. *Id.*

8. 15 U.S.C. § 1691c–2(f)(2). Further, a financial institution must (i) retain this information for at least three years; and (ii) make the information available to any member of the public, upon request, in the form prescribed by the CFPB by regulation.

9. 15 U.S.C. § 1691(a).

10. Although ECOA does not expressly exclude leases, the Federal Reserve Board has previously indicated that true leases are not considered "credit" and are mutually exclusive finance transactions. 50 Fed. Reg. 48018, 48020 (1985). The term "purchase lease" refers to lease contracts with no or a nominal purchase option and the end of the lease term, as provided in the Truth in Lending Act. See 15 U.S.C. § 1602(h). *See, however,* Brothers v. First Leasing, 724 F.2d 789 (9th Cir. 1984), *cert. denied,* 469 U.S. 832 (1984) (holding that ECOA applies to consumer leases); *cf. Liberty Leasing Co. v. Machamer,* 6 F.Supp.2d 714 (S.D. Ohio 1998) (explicitly rejecting the *Brothers* ruling that a lease obligation, as a matter of law, is "credit" as defined in the ECOA and, instead, relying on the 1985 FRB official staff interpretation, which expressly rejected the *Brothers* ruling).

11. For a detailed discussion of the differences between a "true lease" and a lease that is a disguised financing agreement, *see* Equipment Leasing and Finance Association, *The Executive's Guide to Remedies*, Ch. 1 (Jan. 9, 2015), at: www.elfaonline.org/issues/legal/PDFs/Remedies.pdf.

12. Consumer Fin. Protec. Bureau, *Defining Larger Participants of the Automobile Financing Market and Defining Certain Automobile Leasing Activity as a Financial Product or Service*, at http://files.consumerfinance.gov/f/201506_cfpb_defining-larger-participants-of-the-automobile-financing-market-and-defining-certain-automobile-leasing-activity-as-a-financial-product-or-service.pdf (to be codified at 12 C.F.R. Parts 1001 and 1090).

13. Commentary to 12 C.F.R. Parts 1001 and 1090; Defining Larger Participants of the Automobile Financing Market and Defining Certain Automobile Leasing Activity as a Financial Product or Service (80 Fed. Reg. 37501, June 30, 2015).

14. *Id.* at 37502. *See* 12 U.S.C. § 5481(15)(A)(ii) (containing the definition of "Financial Product or Service").

15. 15 U.S.C. § 1691c–2(a).

16. 15 U.S.C. § 1691(d)(2)–(3); 12 C.F.R. § 1002.9(a)(3).

17. Warren W. Traiger, *Banks Should Steel Themselves for Fair Lending Game-Changer,* American Banker, Aug. 12, 2014, www.americanbanker.com/bankthink/banks-should-steel-themselves-for-fair-lending-game-changer-1069275-1.html.

18. Press Release from U.S. Rep. Robert Pittenger (June 11, 2013), at https://pittenger.house.gov/sites/pittenger.house.gov/files/wysiwyg_uploaded/Pittenger_RightToLend_2.pdf.

19. Current Regulatory Plan and the Unified Agenda of Regulatory and Deregulatory Actions, CFPB; Business Lending Data (Regulation B), at: www.reginfo.gov/public/do/eAgendaViewRule?pubId=201510&RIN=3170-AA09.

20. *Id.*

21. Letter from U.S. Rep. Donald M. Payne Jr. et al. to Dir. Richard Cordray (Aug. 21, 2015), at http://payne.house.gov/sites/payne.house.gov/files/documents/House%20letter%20to%20CFPB%20Director%20Cordray.pdf; Letter from The Hon. Maxine Waters to Dir. Richard Cordray (July 8, 2015), at http://democrats.financialservices.house.gov/uploadedfiles/07.08.2015_-_cmw_ltr_to_cfpb_and_fed.pdf.

22. *See:* www.consumerfinance.gov/newsroom/cfpb-finalizes-rule-to-improve-information-about-access-to-credit-in-the-mortgage-market/.

23. Section 1071 of the Dodd-Frank Act, CFPB General Counsel Letter, April 11, 2011 (at: http://files.consumerfinance.gov/f/2011/04/GC-letter-re-1071.pdf).

24. *See:* www.consumerfinance.gov/blog/fall-2015-rulemaking-agenda/.

25. 12 U.S.C. § 2801, *et seq.*; 12 C.F.R. § 1003.1 *et seq.*

26. 15 U.S.C. § 1691c–2(d).

27. *See, e.g.,* Stephen T. Whelan, *Equipment ABS Today: New, Improved!,* Journal of Equipment Lease Financing, Fall 2015, p. 4.

28. Commentary to 12 C.F.R. § 1002.6(a)–2; Interagency Policy Statement on Discrimination in Lending (59 Fed. Reg. 18267, April 15, 1994).

29. Commentary to 12 C.F.R. § 1002.6(a)–2; *Texas Dept. of Housing and Community Affairs v. Inclusive Communities Project Inc.*, 135 S.Ct. 2507 (2015).

30. *Id.*

31. *Texas Dept. of Housing and Community Affairs v. Inclusive Communities Project Inc.*, 135 S.Ct. 2507, 2518 (2015).

32. *Id.* at 2518.

33. *Id.*

34. *Id.* at 2520–1.

35. Charles B. Wendel, *The Impact of Alternative Finance on the Equipment Finance and Leasing Industry,* Journal of Equipment Lease Financing, Spring 2015, p. 2.

36. Big Data: A Tool for Inclusion or Exclusion: Understanding the Issues. FTC, January 2016. www.ftc.gov/system/files/documents/reports/big-data-tool-inclusion-or-exclusion-understanding-issues/160106big-data-rpt.pdf.

37. Steve Lohr, *At New Digital Lenders, Math Rules,* New York Times, Jan. 19, 2016.

38. 15 U.S.C. § 1691c–2(b).

39. 15 U.S.C. § 1691c–2(h)(1); *see supra* Note 2 (discussing "financial activity").

40. For example, in April 2014, New York State Department of Financial Services Supt. Benjamin Lawsky became the first state regulator to sue an auto finance company to enforce the DFA's Title X prohibitions against unfair, deceptive, and abusive acts and practices (UDAAP). Although state authorities generally are limited to enforcing Title X against state banks and nonbank financial service companies, these types of actions bring into sharp focus the full scope and reach of the Title X's enforcement provisions and are likely to inspire similar state actions.

41. 12 U.S.C. § 5552(a). In March 2014, Illinois Attorney General Lisa Madigan announced a suit against a lender for allegedly offering a short-term credit product designed to evade the state's usury cap. The complaint alleged violations of the DFA and sought restitution, civil penalties, disgorgement, and an order nullifying all existing contracts with Illinois consumers.

42. 15 U.S.C. § 1691c–2(f)(2)(A).

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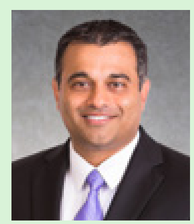

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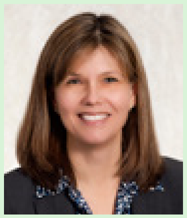

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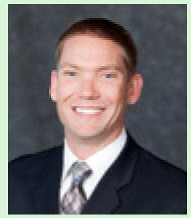

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