DISTRIBUTED GENERATION IN THE U.S.
PRACTICAL ISSUES IN PROJECT DEVELOPMENT

Frederick R. Fucci
Thelen Reid & Priest, New York

IBA Section on Energy and Resources Law Conference
May 11, 2004 – San Francisco

Distributed generation, referred to more colloquially as DG, has tremendous promise for providing efficient, technologically advanced and environmentally friendly capacity for the supply of electricity in the United States, but developers of DG projects continue to struggle with practical and regulatory obstacles in realizing the potential of the market. As an attorney who represents a developer of these projects, and as a partner of a firm who represents several of them, I will in this paper describe some of the obstacles we have faced to get DG capacity in place, how we deal with them and throw out some ideas about how the market could be facilitated through regulatory improvements.

The Market for Distributed Generation in the United States

Distributed Generation Defined

A threshold task is to set the terms of what we mean by DG. One definition used in the industry is small (typically 50 MW or less) electric generation plants using either combustion based technologies, such as reciprocating engines and turbines, or non-combustion based technologies, such as fuel cells, located on or near the premises of end-users. A typical project would be a natural gas-fired cogeneration or combined heat and power (CHP) plant or reciprocating engines on the premises of an industrial or commercial user. The size could be from as small as 150 kW or as large as 40-50 MW. My experience has been that the typical project is in the 1-2 MW area or 5-15MW, which seem to be sweet spots in the market. The plant can either be owned by the customer, in which case the developer’s job is a design-build type of arrangement with an operating and maintenance agreement afterwards, or it can be owned by the developer (usually called an energy services company or ESCO) even though it is on the customer’s premises, in which case the ESCO enters into an energy service agreement, a type of turnkey arrangement where the ESCO designs and builds the plant, runs it and sells to the customer the output in electricity and thermal energy – at a price that is discounted from what the customer would have to pay from the utility. In many cases, the customer asks for a guaranty from the ESCO or its parent that some level of savings will be achieved. The energy services arrangement is more common than the design-build/O&M option in
my experience. The term of an energy services agreement is usually 10 years, although 5 is not uncommon and I have seen up to 15.

Projects using renewable technologies, such as wind, solar and biomass, share many of the characteristics of DG projects and suffer from some of the same regulatory constraints, but they have particular characteristics that make them beyond the scope of this paper and have been amply dealt with in other presentations to the conference.

The Benefits of Distributed Generation

By further way of introduction, there are many important benefits of DG –

- It is a comparatively inexpensive and rapid way of adding capacity, especially in service areas that are geographically constrained or suffer from transmission bottlenecks;

- DG can save the end-user money, especially at times when energy prices are high, because the cost of the transmission and distribution infrastructure is theoretically not factored into electricity prices and because there is a big advantage is reducing demand charges during peak pricing periods;

- DG can provide an end-user with an opportunity to make money by allowing an end-user to sell excess power back to the grid or into an organized market, depending on whether the plant is interconnected to the grid and how it is sized;

- DG can dramatically improve reliability for the end-user because an on-site plant can be configured to be an emergency generator as well and the customer has power even during grid failures – this is particularly attractive for customers who have critical loads, such as hospitals, government installations, server hotels and telecom switching stations; DG can also improve reliability in the transmission and distribution system – each kW of on-site power generation removes the same amount from the transmission and distribution system, easing congestion;

- The thermal energy is very useful, either for running industrial equipment, supplying hot water and providing heat in winter and chilled water for air conditioning in summer; and

- DG is environmentally friendly, offering low sulfur oxide (SOX) and nitrogen oxide (NOX) emissions, with some technologies, such as fuel cells, virtually eliminating SOX and NOX emissions.

Scope of the Potential DG Market in the United States

As a measure of the scope of the potential of the DG market in the United States, a Department of Energy Study from 2000 estimated the potential market for CHP
installations to be greater than 77,000 MW, including 19,000 MW for schools/colleges/universities, 18,000 MW for office buildings, 8,000 MW for hospitals and 6,500 MW for hotels and motels. If one adds in the potential for all sorts of industrial and government installations, the number is probably much greater than that. In this DOE study, 50% of the on-site CHP potential was identified in nine states: California, Florida, Illinois, Michigan, New Jersey, New York, Ohio, Pennsylvania and Texas. Incidentally, while there is some overlap in these estimations with the amount of electricity that could be generated by wind, solar and biomass, the estimations generally don’t include the market for renewables. In short, a huge amount of electric generating capacity could be added in the United States using power generation technologies and fuels that are far cleaner and more efficient than the capacity represented by traditional large-scale generation – and without the need to transmit the power long distances over aging and over-burdened transmission lines. The same can be said for most other industrialized countries and the emerging economies as well.

**Players in the Market**

By final way of introduction, mention should be made of who the players are in the DG market in the U.S. For reciprocating engines, there are about a half a dozen important manufacturers: Caterpillar, Cummins, Generac, Coast Intelligen (using MAN engines with its own heat recovery technology), Hess Microgen and Teco Gen. For microturbines, the top half a dozen manufacturers are Capstone, Ingersoll-Rand, Turbec, Elliot Energy Systems, Bowman and Kawasaki. Larger gas turbine manufacturers include GE and Solar Turbines. The market leaders for fuel cells are UTC Fuel Cells (an affiliate of United Technologies), Fuel Cell Energy, a NASDAQ-listed company that receives a lot of DOE research funding, Siemens Westinghouse, Ballard and Plug Power.

There are many ESCOs throughout the country developing projects and installing and packaging DG systems, too many to mention really. They are either independent companies or utility affiliates.

**Project Implementation**

With some idea then of the potential of the market and who the players are, the next section of this paper will consider some of the nitty-gritty of putting projects together, so as to highlight why in many cases the potential of the market is not being realized. In fact, DG projects are not easy to put together, in spite of their modest size.

**Economic Considerations - Incentives**

The economic considerations that go into whether a company would take itself off the grid are not really in the lawyer’s realm, but there are some things counsel can help the client analyze. A key factor is the utility tariff structure in the service territory – what tariff the customer has before the DG project and what tariff category it would fall into with the DG plant. While some end-users are willing to take themselves off the grid altogether, in most cases it is important that the customer retain its utility service.
agreement and interconnection to the grid so that it can switch over to grid power if the DG plant fails or has to be shut off for maintenance. Interconnection also allows sales of power if the end-user’s load goes under the capacity of the plant.

Utilities in some service territories have been taking the position that taking a customer off the grid but allowing to switch back over to grid power in the case of a shut-down means that they are free-riders for the cost of maintaining the transmission and distribution systems and their other stranded costs. In some places, utilities have succeeded in gaining public service commission permission to factor stand-by charges into the utility service agreement with on-site generators or in imposing grid exit fees. These can have the effect of making DG uneconomical.

Fuel cells receive more favorable treatment from the State regulators, particularly in California. California has its so-called Rule 21, which sets interconnection standards for investor-owned electric utilities. Some types of fuel cells meet the strict emission standards requirement of the California Air Resources Board standard for 2007 and have been designated as an “ultra-clean” distributed generation technology. This exempts them from stand-by charges and grid exit fees. This characterization also allows end-users to sell back unused power to publicly owned utilities at established rates.

New York has relatively new policies for encouraging installation of DG plants, although the State Public Service Commission is one of the ones that have allowed the utilities to impose standby tariff categories for DG users that want to retain the grid as a back-up. Nonetheless, effective February 1, 2004, several investor-owned utilizes agreed to exempt some fuel cell plants from stand-by charges if the installation represents less than 15% of the customer’s maximum potential demand. This is a rather grudging concession and not one that exactly sets a fire under the development of DG. It’s a lot more interesting a prospect to size your DG plant to meet your average load and peak-shave, saving on demand charges.

Another economic issue counsel could be helpful with is the analysis of incentives and the conditions for obtaining them for a particular project. In some states and municipalities, there are tremendous incentives for DG including tax breaks, subsidies for building demonstration projects and other incentives that can make a project worthwhile. These are very local in nature and can vary by municipality to municipality within the same state, so they have to be studied carefully on the most local level. In New York City, there are several important property tax advantages that come into play through a complicated mechanism. In New York State, the State agency responsible for promoting more efficient energy use (known as NYSERDA), will pay a significant part of the project cost. I’m aware of a project to install an on-site CHP plant where NYSERDA has agreed to pay almost half the cost of it.

For fuel cells, the incentives can be even greater. The California “Self-Generation Program” provides $100 million per year of incentive funding for “ultra-clean” technologies on the basis of $4,500 per kW up to 50% of project costs. This program has been extended through 2007, enabling over 20MW of project funding per year.
On the Federal level, for fuel cells, there is a “Federal Stationary Fuel Cell Incentive Program” that grants funds to fuel cell power plant buyers, providing up to $1,000 per kW of plant capacity, not to exceed one-third of total program costs. The program budget for this in fiscal year 2004 is $7.5 million. The Energy Policy Act of 2003 (H.R. 6), which was not passed by the Congress due to the failure of the Senate to obtain cloture of the debate, contained new incentives for fuel cells and CHP plants, which included: (i) an investment tax credit of 20% of $1,000 per kW, whichever is less, for fuel cell power plant installations; and (2) an advanced power system technology incentive program which would provide a 1.8 to 2.5 cents per kWh subsidy to owner-operators of qualifying facilities, including fuel cells, turbines and hybrid power systems. So far this year there has been all sorts of maneuvering in Congress to either re-introduce the bill as a whole in an attempt to obtain the remaining votes for cloture in the Senate (it failed by only two votes last year) or to pass parts of the bill as add-ons to other legislation. Neither one of these techniques has had much success so far, but we can expect that some form of legislation will pass at some point relatively soon and that these types of incentives will be in the next expression of Federal policy, since they are not really very controversial.

In spite of the potential savings and the incentives, DG technologies are still relatively expensive, however – particularly fuel cells. The market needs to achieve a greater scale for the manufacturers andESCOs to be able to offer DG as a real economic alternative to grid-power. The argument for DG has been a hard one to make the past few years since the independent power developers built out so much merchant capacity in the latter part of the 1990’s, only to have this capacity under-utilized or idled altogether by the slackening in demand brought on by the general economic downturn and the gyrations in the market caused by the California crisis. With natural gas prices the way they were until recently, grid power was hard to beat. Of course, the economy has changed course in the past few months and natural gas prices are going way up. In some places in the country, there could be strain on generating capacity resources fairly soon. In other places, some market observers say it could still take years for demand to catch up with the over-building of the 1990’s. Nonetheless, the trend now to economic upturn coupled with higher energy prices auger relatively well for the economics of DG.

**Interconnection**

An issue in every project is interconnection to the grid. If a CHP plant is interconnected, it can be one of two kinds in this respect – either with induction or synchronous generators. Induction generators cannot work without the grid – they need it to be “excited”, as the engineers say. Synchronous generators run in parallel to the grid and don’t need the grid to work (although they still need gas delivery if they are natural gas plants). If a DG plant has induction generators, you lose one of the big benefits of DG – back-up power. Unfortunately, some utilities make it virtually impossible to synchronize a CHP to the grid due to grid stability concerns – or they would allow synchronization only with installing expensive protecting relaying in a substation, thus killing the economic benefits of the project.
Engineers have debated whether these grid stability concerns are well-founded or not. Some people in the industry suspect that these concerns are overblown because the utilities are hostile to the idea of having a lot of customers taking themselves off the grid. Other industry observers feel that utility distribution and transmission systems in some areas of the country are so particular to the service territory and patched together by people who are no longer there that the grid managers are in fact simply not sure what will happen if a lot of CHP plants are running in parallel to the grid and feeding power back on to it when the load of the customer calls for it – so, to be on the safe side, they discourage it. In all events, in most cases these types of safety and reliability concerns fall into the realm of individual State regulation. As a result, there can be wide differences across the country in the regulation and practice of DG interconnection and the extent to which State regulators are willing to confront recalcitrant utilities. This puts both a practical and a financial burden on projects, in that an ESCO and its counsel have to study and be aware of many varying requirements – and what is written in black and white may not reflect the reality of the situation on the ground.

In my view, interconnection issues are the greatest single drag on the CHP market. Uncertainty over whether a utility will allow parallel operation or interconnection at all, what types of conditions it will put on it and how long it will take to get final approval causes all sorts of problems in projects. The biggest one has to do with timing of the installation. A modestly-sized CHP plant can be realized from design approval to substantial completion in about six months, sometimes less. However, ESCOs have trouble committing to firm substantial completion dates because they're not sure how long the utility will take to approve the interconnection – and then, the ESCO, end-user and equipment supplier get into a protracted debate over who will bear the risk of utility delays and what happens if it doesn't approve at all. This is exacerbated by the fact that the equipment supplier, to meet the substantial completion date, has to release the equipment from the manufacturer well before the utility gets around to approving the interconnect. Consequently, the parties have to negotiate what to do with the equipment if it is released and then can't be used – or has to be modified. In the end, it can be impossible in a project for an ESCO to commit to a firm completion date, which leaves the end-user wondering why they are bothering to install the CHP plant at all. I worked on one project where our client's partner was too optimistic about the utility's allowing synchronous generators and actually went out and bought the synchronous equipment, only to have to switch it for induction equipment. Then we had to rescure the project to install diesel back-up generators because the back-up power was important to the customer.

To be fair, there are many utilities across the country that do not make it difficult to interconnect DG plants and do not have prohibitive tariffs for companies who want to use the grid for stand-by power. On the contrary, they see the benefits of DG in terms of relieving grid congestion or themselves of the burden of adding expensive new capacity, particularly in the new environment of "back-to-basics" in market regulation, meaning a new focus on the provider-of-last-resort obligations of utilities.
Also on the positive side of the ledger, the industry and the federal government recognize the drag that interconnection uncertainty puts on the DG market. There are two important initiatives in the works — one on the technical side and the other on the regulatory side that, if implemented, will provide relief.

On the technical side, an industry engineering association, the Institute of Electrical and Electronics Engineers, has been working for some time now to create a standard addressing the technical requirements of interconnecting DG plants to the grid. This standard is still under development. Once it is finished, many in the industry hope that it will be adopted nationally — a tall order, given the disparities in grids — but something to be strived for in all events.

On the regulatory side, in July 2003 the Federal Energy Regulatory Commission (FERC) adopted rules for generator interconnection agreements and procedures for facilities over 20 MW. It reaffirmed those rules in March 2004. The rules require the approximately 175 investor-owned utilities in the U.S. that own, control or operate interstate transmission service to offer non-discriminatory, standardized interconnection service. The rules amend a previous FERC Order (No. 888) having to do with “open access” of merchant generators to transmission systems. For these facilities over 20 MW, the FERC addressed the issue of what type of financial burden a merchant generator has to bear for the maintenance of the transmission system and the upgrades needed to connect the distributed generations. The transmission provider has the option of charging the interconnected generator a transmission rate that is the higher of the incremental cost for the network upgrades required to interconnect the generating facility of an average embedded cost rate for the entire transmission system (including the cost of network upgrades). Basically, by allowing transmission providers to charge the higher of an incremental cost rate or an embedded cost rate, the FERC is signaling that it will not allow transmission customers, which includes the transmission provider’s native load, to subsidize network upgrades required to interconnect merchant generator. However, there is a complicated system of credits from the transmission provider to the merchant generator related to the transmission delivery services the merchant generator actually takes from the system, a discussion of which is somewhat beyond the scope of this paper.

What is of more interest for the bulk of the DG market are companion rules the FERC proposed in August 2003 for small generators, those defined to be under 20 MW. As noted above, many DG projects fall below 20 MW, so these FERC rules are of keen interest. As of today, however, they are still proposals and not final. The proposed rules include standard procedures that distributed generators and grid operators (those that are jurisdictional public utilities) have to follow during the interconnection process. The FERC has also proposed a standard “Small Generator Interconnection Agreement”.

Before getting into the details of the proposed rules, it would be well to pause and consider some terminology. Most of these rules talk about interconnection to transmission systems. A transmission system can include both the transmission provider’s high voltage or low voltage systems. In DG projects, when you are considering interconnection, you are usually talking about connecting to the utility’s local
distribution system. In the proposed FERC rules, there is a provision to the effect that if the distributed generator wishes to connect to a transmission provider's distribution grid for the purpose of making a sale in interstate commerce, the costs of the distribution upgrades required can be directly assigned to the distributed generator. In other words, even under the new FERC rules, the distributed generator has to pay. It happens of course that a distributed generator wants to interconnect to a transmission or distribution system solely for the purpose of back-up power, but part of the real economic interest of DG and the ESCOs that are developing projects is to be able to sell excess load to the market. In this case, then, the FERC rule confirms today's reality that the distributed generator has to pay the cost of the grid upgrade, which, the utility, if it chooses, can make prohibitively expensive.

With respect to transmission network upgrades, the new rules for small generator interconnection follow the policy of the rules for larger facilities, namely that the distributed generator has to pay the cost of the network upgrades, but the portion of the cost of the upgrade that is not related to the actual usage is refunded to the distributed generator in the form of credits after commercial operation of the plant. There is no such refund concept for plants connecting to the location distribution grid, although there is some ambiguity in the rules related to the way that the term “Transmission System” is defined that could lead one to conclude that there credits could be claimed. This aspect of the rules could benefit from some clarification, but distributed generators have to assume for now that they will have to pay for all distribution system upgrades required for interconnection.

The cost issues aside, there are some aspects of the FERC's proposed rules that, if implemented, will help move the market in the direction it needs to go to make projects easier to realize, that is to say standardization of procedures on the national level so that projects are less complex. To start from the smallest projects, those under 2 MW, the proposed interconnection would be evaluated using “Super-Expedited Screening Criteria”. The FERC is envisioning that certain types of distributed generating equipment could be pre-certified by a national testing laboratory as having met industry and safety standards. This seems to be modeled to some extent on something the New York Department of Public Service does, which is to maintain a list of approved equipment on its website. The FERC's policy in suggesting this registry is to encourage cooperation and information sharing among the States and industry participants. If the distributed generator is proposing to use this pre-certified equipment, the proposed rules require the transmission provider to offer a standard interconnection agreement.

For plants between 2 and 10 MW, the new rules suggest “Expedited Screening Criteria”. The Expedited Screening Criteria do not make reference to pre-certified equipment, but require instead that the distributed generator make an application to the transmission provider and that the transmission provider reply within a certain amount of time with the information it needs to determine if the plant can be connected safely and reliably. If, after receiving the information, the transmission provider makes a positive determination, the parties can proceed to executing the standard interconnection agreement. If it does not, then the distributed generator and the transmission provider
have to have a “scoping meeting”. If there is no agreement as to the interconnection after that, the distributed generator has to undertake a feasibility study showing the impact on the transmission system. If this feasibility study shows a potential adverse impact on the distribution system, then there has to be a “Distribution Interconnection System Impact Study” as well. The result of these studies will determine whether and under what circumstances the plant can be interconnected. This procedure has the potential of being burdensome and expensive, but the transmission provider has to respond within certain deadlines. In order to give the transmission provider an incentive to be cooperative, the rules provide that the cost of the feasibility studies has to be borne by the transmission provider if it shows that there will be no “Adverse System Impact”. If it shows such an adverse impact, the cost has to be borne by the distributed generator.

For plants between 10 and 20 MW, the rules are essentially the same for generators over 20 MW, which is to proceed right away to the feasibility studies if the parties can’t agree on what the potential adverse impact and the fixes might be, with the deadlines and cost incentives outlined above.

One further point to note is that the FERC’s jurisdiction does not extend to all players in the industry. The rules may be binding on all “jurisdictional public utilities”, which excludes a number of industry players, such as state-owned utilities. Also, the utility industry has expressed the view in its comments that the scope of the FERC’s jurisdiction in these rules does not extend to distribution systems, which should remain the subject of individual state jurisdiction. The FERC noted these objections and it’s unclear how it will come down on this issue in its final rules, although it seems to be inclined to interpret its authority to extend to distribution systems, as least insofar as interconnection for purposes of making power sales are concerned. Nonetheless, this crazy-quilt of potentially overlapping state and federal authority is a result of historical factors in the United States and cannot be easily overcome.

In sum, these rules, like the proposed technical standards, are a step in the right direction, no doubt, in that they set a framework for all stakeholders in the process to evaluate the risks and possible impact of interconnecting a distributed generator and set deadlines and incentives for moving to an agreement. The rules also take away the potential for arbitrary actions on the part of the utilities by making reference to feasibility studies performed by a third party engineer, albeit with certain consequences for the timing and costs of projects. On the key issue of connection to distribution grids, they reinforce the idea that the cost of upgrades has to be borne by the projects.

Policy Concerns Related to General Regulation of Electricity

Another drag on the DG market in the U.S. is the complexity of the more general federal regulatory framework relating to power sales. If there is an interconnection, and thus any possibility of power going back to the grid, the developer of a project has to consider the effect of the Public Utility Holding Company Act of 1935 (PUHCA) and the Federal Power Act (FPA), the two principal federal statutes governing the sale of electricity in the U.S. In order to avoid this, some projects remain strictly “inside-the-
fence”, meaning that the DG plant only supplies the host and there is no possibility that power will move back to the grid. As mentioned above, however, most projects will want interconnection either for back-up security or for the possibility of making money from power sales. If this is the case, then PUHCA and FPA concerns have to be addressed.

**PUHCA and FPA Concerns**

If a distributed generator cannot obtain an exemption from PUHCA, it risks being regulated as a utility by the federal government, something the host, which typically is an industrial company, a university, a hotel or a hospital has absolutely no interest in doing, or even really hearing about. Most business people considering the potential benefits of DG have no idea what this all means.

In brief, the owner of the plant, whether the host facility or the ESCO, and whether or not it is a utility affiliate, has to get a PUHCA exemption or risk being regulated as a utility. The exemption can take one of two forms – certification as a qualified facility (QF) under Public Utility Regulatory Policies Act of 1978 (PURPA) or obtaining the status of an exempt wholesale generator (EWG). QF certification is the more typical route if waste heat is being used. EWG structures can also be used, but they require selling all of the output of the plant to a power marketer who then sells it back to the end-user.

QF certification is relatively straightforward if the owner of the plant is not a utility affiliate. The plant just needs to meet the technical operating and efficiency requirements in the federal regulations, which focus mainly on the amount of waste heat that is recovered. If it is a utility affiliate, though, the PURPA regulations prevent the utility affiliate from owning more than a 50% equity interest in the plant – so the utility affiliate has to find a partner and form a project company where the ownership interest is split. This adds another development expense to the project, because the ESCO has to negotiate its arrangement with the partner, and it adds a risk factor related to the behavior of the partner, which often are small, entrepreneurial companies that are not well financed. If the utility affiliate takes a 50% interest in the project company, you then have to deal with deadlock and other typical joint-venture control issues, which is burdensome for a small project. Incidentally, if the host owns the plant, but has a utility affiliate running it, you don’t avoid the PURPA issue because the FERC has interpreted utility operational control over a CHP plant as being tantamount to ownership.

The FERC has issued many determinations on the issue of whether a utility has more than a 50% interest in a plant using an analysis of which party has the majority of the “stream of benefits” from a project, which include operational control, profit-sharing, tax benefits and several other factors. To my knowledge, FERC has never indicated what weight it gives to these factors, which drives clients crazy and induces them to have lawyers undertake how-many-angels-can-you-fit-on-the-head-of-a-pin analyses of how the various stream-of-benefits factors lean in a particular project. In short, the conclusion
a lawyer must draw on whether a utility affiliate has a more than 50% interest in a plant is of great importance in how projects are structured or whether they are implemented at all.

I’ve avoided too elaborate a discussion of PUHCA and PURPA in this paper, because there is a decent chance that PUHCA will be repealed altogether in the relatively near future. The version of the Energy Bill that passed the House of Representatives last December – H.R. 6 – would have repealed PUHCA and eliminated the PURPA restrictions on utility ownership. If PUHCA is in fact repealed at some point in the relatively near future and the PURPA restrictions on utility ownership go away as well, this will be, in my view, a boon to the DG industry. The regulatory framework will be greatly simplified and more financially substantial players will be able to enter the market without fear of unintended adverse regulatory consequences. At this point, it’s hard to read the tea leaves, however, as to whether PUHCA will be repealed this year. Many people in the U.S. want to see this and have been trying for a long time to bring it about, missing their chance by the slimmest of margins recently. The chances may not be that promising this year, which then throws the question to the results of the November 2004 Congressional and Presidential elections, where the deck will be reshuffled in ways that can’t be predicted right now.

Financing DG Projects

I’ve had many calls from existing clients, potential clients and other partners in my firm asking, “How do you finance DG projects?” Most people assume that these deals can be financed on a project basis, but there really aren’t many financial institutions interested in such small projects. Also, potential project financiers look at these projects, small as they are, as typical project financings and assess all the performance risks typically associated with power projects. Usually the conclusion is that the size of the deal does not justify the resources that would be needed to do the proper due diligence and to project finance it.

Even if a lender were to consider a project financing, their willingness to do it depends on the credit of the offtaker, the host, so this enters into the formula. If the customer’s credit needs to be used to support the financing, this can kill a deal because the customer may not want to use its balance sheet in that way. Sometimes the pitch that ESCOs make to customers is that they will get their own generating capacity and save a guaranteed amount of money on their utility bills without making any capital expenditure. This is all right if the ESCO has its own financing in place, but sometimes when it comes time for the financial institution to look at the deal, they want to involve the customer in any case and this creates bad feelings.

If the customer is willing to use its own credit to support the financing, one thing that does help make these projects happen is if the customer has some sort of tax-free financing capability, because the lower financing costs can be passed through to make the economics more attractive. It’s for that reason that you see a lot of universities, public hospitals and even municipal government utilities that use a lot of power such as wastewater treatment plants interested in DG. Also, the federal government and some
state governments are pretty enthusiastic supporter of energy performance contracting, which often includes some form of on-site cogeneration, and this helps the market. Massachusetts is a real leader in this field.

Unless ESCOs around the country are working with more innovative financing techniques than I have seen, the main way DG projects are financed is off the balance sheet of the ESCO. Either the ESCO just buys the plant or uses its own credit lines and takes the economic risk or it enters into a lease financing arrangement, but the leasing company invariably wants a substantial party to stand behind the lease payment obligations, so the deals cannot be financed without parent company or affiliate guarantees.

Some ESCOs have looked at the DG market and concluded that the deals are too small for individual project-like financing, but that if a number of them could be put together using form documents, the cash-flows generated could be securitized in the medium term. In order to get the necessary documentation in place and get the critical mass of projects up and running, an ESCO could seek venture capital financing until the exit strategy is implemented. This is an interesting business model, but its success does depend on a big appetite for risk on the part of the VC. Another glitch is that it’s very difficult to get diverse customers to agree to the form documents. For one reason or another, the documents end up being negotiated or customized, so that far too much time and money is spent on getting the energy services agreements into place. This has the effect not only of making the deals more difficult to do, but it makes a take-out financing more difficult because the revenue stream is based on less standardized documents, causing due diligence issues for potential financiers. There is a definite trend on the part of the ESCOs now to put a standard energy services agreement in front of the customer and say that this is the way the documentation has to look. However, when faced with the prospect of losing the sale, the ESCO backs off and consents to negotiate it. On more than one occasion, a customer has said that it wants its own counsel, not the ESCO’s counsel, to draft the documents, particularly if the project is a little larger (over 10 MW). This always spells big trouble for a project. DG project development is, for better or worse, a very specialized area and there aren’t that many lawyers out there who bring together the energy project development, the local regulatory and PURPA/QF experience needed to get a deal done. I have seen very disappointing work product from customers’ counsel, even from firms where you would have thought they had the capabilities, and this bogs down the development.

Performance Risk of Equipment

Another thing I’ve learned from experience is that the equipment used in DG projects is not immune from performance problems. Many of the combustion and microgen manufacturers have had problems. While there have been great technological advances, the parties have to deal in the development phase with the risk of engine failure or sub-standard performance. I’ve been involved in one situation where the equipment just never worked in the first place and another where it worked but tripped a few times a month for no apparent reason. In this situation, the equipment switched the industrial
customer over to the grid when it tripped, as it was supposed to, but there was a slight lag, just a few cycles, and it caused the customer’s production lines to shut down briefly. The customer claimed that its engineers then had to reset the production lines and it lost production and money. Because of this, and the inability of the ESCO to guarantee that there would be no further trips, the customer has thrown in the towel and wants the ESCO to remove the equipment so it can go back to the grid.

Therefore, another important project development consideration is that somebody has to stand behind performance guarantees for the equipment or the customer will not be willing to switch over to DG. If the ESCO is an entrepreneurial company, it will not have the balance sheet to back up the performance guarantees and may try to pass them on to the equipment manufacturers. Most of the equipment manufacturers, however, will only give very limited repair warranties, so there is a gap from the customer’s prospective as to how it will obtain the performance it is expecting. The entrepreneurial ESCOs are run by very intelligent, idealistic and dedicated people, but they can have trouble closing the sale of a CHP plant because the customer can get cold feet about who will stand behind the plant if it doesn’t work right, who will back up the energy savings guaranty, how does the customer know the ESCO will even be around in 5 years, etc.

Many people think that utility affiliates are too cumbersome and risk-adverse to be effective ESCOs, but they do offer one advantage more entrepreneurial companies do not - they have the financial wherewithal to back up the equipment performance and energy savings guarantees. So the market kind of sputters between utility affiliates who have to deal with the PUHCA regulatory issues and have a certain tendency to involve a lot of people because of their culture of risk aversion and nimble entrepreneurial ESCOs that can’t convince the customer they can stand behind the contracts.

**Deal Complexity**

As suggested by all these considerations, a big drag on the DG market is that the projects are just too complicated. They have many of the complications of much larger IPP projects – long term price risk, allocations of other liabilities and risks in the energy services agreement, an equipment supply or design-build component where the host or the ESCO wants to make sure that it gets performance guarantees and warranties, operations and maintenance arrangements or subcontracts which can be tricky and a joint venture or LLC agreement with a 50% member if the ESCO is a utility affiliate and the attendant corporate governance and deadlock issues. Also to be dealt with in the development phase are land-use issues and permitting requirements, which can be very local in nature. I have seen one promising DG program for a chain of department stores collapse because four of the stores were located in a county that considered the DG equipment to be structures for local building permit requirements (the equipment was to be enclosed in containers and put in the parking lots in back of the stores) and the county officials were angry at the department store for not having lived up to a promise to make certain traffic patterns changes when they built the stores – so they denied the building permits.
Our clients are trying to make the deals simpler by standardizing the documentation and streamlining the development process, but the deals have inherent risks that cannot be wished away.

Outlook

Much of this paper has focused on the difficulties in getting DG deals done -- and there are many obstacles to be overcome -- but I don’t wish to sound too negative for the prospects of the development of the market. More and more deals are being done and there are some very interesting examples of how the combined heat and power technology can work and help save a lot of money on energy costs. Some industry observers are very enthusiastic about fuel cells and feel as if this market will truly take off in the next few years. As the players in the market become more used to the idea of DG, as more people are educated as to the potential benefits, including the environmental benefits, as the equipment is installed and tested and corrected and as the country’s power needs continue to grow, DG will come to play a more and more important role in everyone’s thinking about reliability and energy security. As someone involved in the industry, I see people feeling their way through complex issues with great dedication and have the feeling of being involved in something that is about to take off and become much more prevalent. The biggest challenge is on the interconnection issues and we can only be optimistic that the industry technical standards and the regulation will become more uniform so as to alleviate the obstacles we are having to face today.