Introduction to Commercial Procurement of Greenhouse Gas Emissions Offsets[1]

Background Paper for the EPRI Greenhouse Gas Emissions Offset Policy Dialogue Workshop #9

October 2010

I. Background

This paper has been prepared for a workshop to be held by the Electric Power Research Institute (EPRI) on October 28, 2010 in Washington D.C. It is the ninth in a series of workshops sponsored by EPRI in 2008, 2009 and 2010 on the subject of greenhouse gas (GHG) emissions offsets.

The purpose of this paper is to provide background for workshop discussions on commercial procurement of GHG emissions offsets by electric power companies and other entities in the context of the implementation of a potential future mandatory greenhouse gas (GHG) cap-and-trade program. The discussion in this paper also may be relevant in the context of the implementation of a federal regulatory program designed to drive GHG emissions reductions that might allow for the use of GHG emissions offsets to be used in some way for compliance. The paper covers the following topics:

- "Build versus buy": Developing or direct investment in emission reduction projects to obtain offsets, versus purchasing offsets in the market;
- The benefits and challenges of "building;"
- The role of different entities in the offset procurement process
  - Project developers
  - Brokers
  - Carbon funds
  - Banks
  - Exchanges
- "Primary" versus "secondary" offset instruments and markets;
- The benefits and challenges of "buying;"
- Compliance buyers' priorities, options and strategies for procuring offsets;
- Internal structures, required resources and expertise required to purchase offsets; and,
- Options for financing offsets projects and managing risk.

The objective of the paper is to provide a general introduction to commercial procurement of GHG offsets – one that is oriented toward U.S. electric companies and other potential "compliance" buyers that have not been particularly active in the market to date. We note that

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the paper is based on experience to date with offset procurement in the context of the implementation of the United Nation's Clean Development Mechanism (CDM), the European Union's Emissions Trading Scheme (EU ETS) and the Kyoto Protocol (KP). It is possible that future offset programs and markets – and their associated procurement entities and transaction structures and other aspects – may have some important differences from existing programs.

The CDM, one of the "project-based mechanisms" created by the Kyoto Protocol, is the largest offset program in the world that has been developed to date.[2] It has stimulated billions of dollars in investment in reducing GHG emissions, and many observers believe it has contributed to significant levels of emission reductions in developing countries.

Carbon offset credits issued by the CDM (known as Certified Emissions Reductions (CERs)) have become a sort of common currency in the evolving global carbon markets. They can be purchased for compliance use by companies regulated under the EU ETS, by countries that are party to the KP, and by Japanese companies and other entities committed to meeting governmental voluntary targets.

II. Overview of "Build vs. Buy"

A. Build

One of the key choices to be made by entities subject to mandatory GHG emission reduction requirements under a cap-and-trade system that want to incorporate offsets as a component of their compliance strategy, is the question of whether to "build" or "buy" emissions offsets. In this context, "building" refers to a compliance party's efforts to plan and implement its own GHG offset projects, or to become a direct investor in an emission reduction project to share in the multi-year "stream" of offsets (or the "offtake") from the project, and potentially to obtain other benefits from the investment. For the purposes of this paper, "build" does not refer to efforts by electric companies or other potential compliance parties to plan and implement "on-site" projects to reduce GHG emissions within their own power generation or industrial operations.

"Building" is roughly analogous to an electric company building its own power plant. An example of "building" in the offsets context would be an electric power company planning and developing a fuel switching project in a developing country to reduce emissions based on its experience and expertise in such activities. Alternatively, the company may choose to invest in an offsets project based on the implementation of a technology or activity (i.e., biomass or supply-side energy efficiency) designed to reduce GHG emissions. .

To date, companies that have opted to build their own offset projects in the carbon markets have tended to be large entities that have sufficient resources for and expertise in the development of projects. (This expertise, and related resources and internal structures, are discussed in more

[2] The other project-based mechanism created by the Kyoto Protocol is Joint Implementation (JI), which allows industrialized countries or emitters in those countries to invest in projects located within other industrialized countries to generate Emission Reduction Units (ERUs).

detail in Section V.) Similarly, firms that opt to invest directly in offset projects are those that have sufficient resources and expertise to evaluate and make such investments.

1. Benefits of building offset projects

In general, the benefits of "building" relative to "buying" include, but are not limited to, the following:

- Obtaining offsets at a potentially lower price than in the offsets market (as a project owner, the emission reductions from the project are obtained "at cost", rather than at a premium from another project owner). Financial benefits of building or investing in a project may also include secondary revenue streams (e.g. from sales of electric power from the project).

- For companies that develop their own offset projects, there is greater control over the project and its emission reductions than would be the case if the company purchased offsets from another entity. As a result, such companies will have greater "quality control." That is, owners of projects have greater ability to thoroughly understand, and take action to reduce, the risks of the project, including delivery risk – the risk that the project will deliver fewer emission reductions (ERs) that receive approval as compliance instruments than the projected, contracted or offered amount. There are several types of delivery risks, including:

    - The risk that the project will not obtain regulatory approval due to technology-specific considerations;
    - The risk that the technology employed by the project will not operate as planned, and will deliver fewer emission reductions than anticipated;
    - The risk that the "host" country's regulatory authority will not be able to provide its approval for the project, or will change its rules over the life of the project;
    - Investment risks associated with doing business in the host country; and,
    - Risks associated with the seller's credit rating or relative experience developing offset projects.[3]

- Companies that invest directly in offset projects may also have greater quality control than those that purchase offsets in the market, although this benefit may depend upon the investing company's level of engagement in the project.

2. Challenges of building offset projects

The **challenges** associated with "building" rather than "buying" include but are not limited to the following:

[3] These various risks, as well as delays in the project approval and offset issuance process, can significantly reduce offset delivery relative to offered amounts, in addition to delaying the timing of delivery. Compliance buyers carefully monitor the likely dates of delivery for their projects so they can plan and implement compliance strategies.

- Developing an offsets project or investing in a project requires dedicated staff, resources and specialized expertise. (Additional discussion on this topic is provided in Section V.)
- There are significant project and other related risks associated with developing and investing in a project that go beyond the various delivery risks associated with offsets purchased in the market.
- Developing or investing in offset projects represents a "non-core" business for electric companies, whose expertise is in supplying power.
- Given the need for dedicated staff, adequate resources and specialized expertise, "building" may be more of an option for large companies.

B. Buying Offsets in the Market

While "buying" – i.e. purchasing offsets in the market – is undertaken by firms of all sizes, it may be the primary procurement option for small- and medium-sized firms that are not active in developing offset projects, do not maintain large trading desks, and/or do not have staff with the time and expertise to dedicate to managing these activities or to build projects. To avoid having to develop the internal capacity to develop or invest in projects, a portion of firms seek to "keep things simple" and purchase offsets in the market. To date, larger firms also have been large buyers of offsets in the carbon markets – in addition to developing or investing in projects – for a variety of reasons. These include diversifying their approach to complying with their emission reduction obligations and risk management, and other benefits noted below in Section II.B.1.

The following discussion introduces some of the key elements of and distinctions in offsets markets and procurement, including: 1) the distinction between "primary offset credits" and "secondary offset credits," and the related distinction between "primary" markets" and "secondary markets;" transaction structures and associated benefits and risks; 3) benefits of buying in the market; 4) challenges of buying in the market; and, 5) the roles of different entities in the offsets procurement process.

1. Benefits of buying offsets

Controlling costs, hedging existing assets, and reducing corporate risk

As concluded in numerous economic analyses of proposed U.S. GHG cap-and-trade programs in the most recent Congress, the availability of offsets is the most important mechanism potentially available to regulated firms to reduce their compliance costs under such a program.[4] Buying offsets in the market allows electric and other companies to hedge their existing assets, continue to operate them in a carbon-constrained regulatory environment, and avoid premature asset retirement. Buying in the market also provides a way for companies to diversify their compliance strategy, and avoid relying on any one option (i.e., internal emissions abatement or the purchase of emissions allowances). This reduces the risk of failing to meet compliance requirements, or of achieving compliance in a way that is not cost-effective.

[4] The cost-control and other benefits of offsets are discussed in "Emissions Offsets: The Key Role of Greenhouse Gas Emissions Offsets in a U.S. Greenhouse Cap-and-Trade Program," EPRI, Palo Alto, CA: 2010, 1019910, pp. 12-14.

Electric companies have experience as buyers in SO_2 and NO_x markets

The SO_2 and NO_x trading provisions incorporated in Title IV of the Clean Air Act Amendments of 1990 (i.e., the "Acid Rain" program) represented a major change from "command-and-control" environmental regulations to the use of "market-based" approaches. Subsequently, many U.S. electric companies developed strong internal expertise and infrastructure necessary to support trading SO_2 and NO_x emissions allowances to achieve compliance with emissions limits. Given this experience, the purchase of GHG offsets in the market does not represent an entirely new and unknown activity for U.S. electric companies. However, GHG *offsets* differ in key ways from emissions *allowances*. Offsets are much more risky instruments than emission allowances, which represent a government issued permit to emit one ton of a given air pollutant. As discussed below in Section III, not all CERs purchased in the market are guaranteed compliance instruments. Guarantees (and prices) depend upon the type of offset purchased and the associated transaction structure. Therefore, a number of additional risk considerations need to be taken into account when purchasing offsets as compared to allowances

Flexible approach – buy as needed

Buying offsets in the market allows companies to purchase the amount of emission reductions they need to meet compliance requirements, and to make additional purchases as needed. However, it is important to recognize that in the early years of the development of a new offset program, there is a risk that available offset supply will not be sufficient to meet compliance demand.[5] In contrast, "building" – developing or investing in an offset project – does not allow for the same flexibility. The amount of offsets generated by a project a company develops or invests in may not exactly match its compliance needs. In addition, an offset project cannot provide additional emission reductions at the end of a compliance period to address any shortfall the company might face.

2. Challenges of buying in the market

Higher cost than a successful "build"

Some of the challenges of buying in the market are similar and directly related to the benefits of "building." For example, offsets purchased in the market may be more expensive than the emission reductions generated by a project that a company develops or invests in, given that those reductions effectively can be obtained "at cost." However, this may not be the case if an offsets project experiences unexpected problems and higher costs.

Delivery risk

As a buyer in offset markets, it is a challenge to obtain complete information on the various delivery risks associated with an offset project. Companies that develop their own offset projects

[5] EPRI, Palo Alto, CA: 2010, 1019910, pp. 17-18, op. cit.

may have greater ability to understand and take action to reduce their delivery risks. However, companies that buy in offset markets can use different approaches to mitigate delivery risk – such as purchasing a portfolio of projects diversified by country and technology, or by participating in a carbon fund with a diversified portfolio. These approaches are discussed further below.

The need to build expertise in areas relating to offsets procurement

To ensure they are well informed before purchasing offsets, some offset buyers may seek to develop internal expertise in areas such as contracting for offsets, evaluating delivery risks from projects, and factoring these risks into offset pricing. However, some buyers do not have the resources to develop such expertise. These buyers may benefit from participating in a carbon fund, as discussed in section IV below, or by working with brokers or others who can provide expertise where needed.

III. "Primary vs. Secondary" Markets and Offset Credits

Emissions offsets may be purchased from several types of entities in the carbon market. These entities may be active in the "primary" or "secondary" markets, or both. The primary market involves direct transactions between buyers and offset project owners. Firms may purchase emission reductions directly from project owners, or directly invest in projects and thereby obtain ownership of emission reductions from the project. The secondary market involves transactions in which offsets already have been issued or for which a delivery guarantee has been made, often where the seller is not the original owner of the carbon asset.

A similar distinction can be made between *primary and secondary offset credits*. In the market for offsets created under the CDM[6] program – in which compliance buyers[7] procure offsets to meet emission reduction requirements imposed by the EU ETS and the KP – a significant volume of offsets are traded in advance of the offsets having first secured all necessary domestic and international regulatory approvals. These not-yet-approved offsets are known as "**primary CERs**" (i.e., Certified Emission Reductions). Again, by analogy to commercial operations in the

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[6] In this paper, the CDM market and related offset instruments – primary and secondary CERs – are used to illustrate offset market concepts and entities that are likely to be relevant in other offset markets. In general, the paper does not discuss the market for Emission Reduction Units (ERUs) from the United Nation's Joint Implementation (JI) mechanism. Like CERs, ERUs – which are emission reductions from projects in countries with economies in transition, such as Russia and Ukraine – may be used by buyers to meet their emissions targets under the EU Emissions Trading Scheme and the Kyoto Protocol. The market for ERUs is not unimportant, but it is much smaller and less mature than the CDM market for a number of reasons. For the purposes of brevity, the paper does not address the ERU market, although buyers can procure ERUs through various approaches, similar to CERs.

[7] The term "compliance buyers" in this paper is used in two related but somewhat different ways. It can refer to buyers who purchase CERs to meet compliance requirements, as distinguished from speculative buyers who are not subject to compliance requirements. "Compliance buyer" also can refer to buyers who generally wish to meet their emissions targets without significant complexity or frequent transactions, as distinct from other buyers which also are subject to compliance requirements, but which engage in more active and complex trading. The latter group includes larger firms in the energy sector which have significant trading experience and greater internal resources and expertise available to develop and implement a comprehensive CER procurement strategy.

electric power sector, buying primary CERs is comparable to an electric company signing a Power Purchase Agreement (PPA) to buy a "strip" of electric energy to be delivered over time.

Primary CERs often are purchased in a **"forward stream"** – i.e., a multi-year stream of offsets of different "vintages." Typically, primary CERs have been transacted in volumes of 10,000 – 1,000,000 tonnes CO_2e per year, often over a 3 to 5 year period.[8] Offset project owners sell primary offsets in advance to finance their projects (in the case of partial up-front payment) or to help obtain financing for the projects (in the case of pay-on-delivery contracts), and to lock in offset sales prices.[9] Typically, primary CERs are cheaper to buy than secondary CERs based upon their stage in the CDM regulatory process, and because most sellers of primary CERs do not provide a **delivery guarantee** (i.e. a guarantee that the seller will deliver valid compliance instruments, whether or not the offset project eventually passes through all regulatory hurdles).

As noted above, secondary market transactions are those that occur after offsets have been issued or a delivery guarantee has been made, and these transactions often do not involve the original offset owner. They often occur when the buyer of primary CERs sells them on to another entity.

In the CDM offset market, the secondary market generally refers to the market for **guaranteed** or **secondary CERs**. In such transactions, the seller – e.g., financial institutions, carbon funds, energy companies, hedge funds, or commodity traders – provides a delivery guarantee, thereby taking on delivery risk in exchange for charging a premium for the guaranteed CERs. Sellers of secondary CERs typically purchase primary CERs early in the project cycle, manage delivery risks across a typically diversified portfolio of projects, and resell offsets to compliance buyers.

For compliance buyers, secondary CERs provide the advantage of minimal risk of non-delivery, but are more costly than primary CERs.[10] Secondary CERs are sold "over-the-counter" (OTC) by banks and brokers and on exchanges. The secondary market also includes a **spot market** for issued CERs which are sold on exchanges – similar to the spot market for wholesale electricity. Such transactions are for immediate, or nearly immediate, payment and settlement (i.e. delivery) of a volume of CERs, in contrast to **forward trades** of primary CERs, which will be delivered in the future as the emission reductions are generated over a period of years. Additional detail on different contract structures in primary and secondary markets is provided below.

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[8] Purchasing periods have typically corresponded to compliance periods under Phase 2 of the EU ETS (2008-12) or the KP (2008-12), both of which covered 5-year periods. When compliance periods change (e.g. Phase 3 of the EU ETS, which will last from 2013 through 2020) it is likely that purchasing periods also will change.

[9] Prices may be fixed or linked to an index (e.g. priced at a percentage of the EU Allowance price on the "settlement date"), or can have both fixed and indexed components.

[10] Other market participants such as traders and sophisticated project developers use secondary markets and financial derivatives such as "call" and "put" options on secondary CERs to hedge their exposure to price or volume (i.e., delivery) risks in primary CER markets, or to attempt to arbitrage – i.e. trade strategically to profit from changing price spreads -- between secondary CERs and EU Allowances World Bank, "State and Trends of the Carbon Market 2009," May 2009, p. 39, http://siteresources.worldbank.org/INTCARBONFINANCE/Resources/State___Trends_of_the_Carbon_Market_2009-FINAL_26_May09.pdf

3. Transaction structures and associated benefits and risks[11]

Primary CERs – forward transactions with payment on delivery and fixed prices

The most common structure for CDM transactions in the primary market is a **forward contract** for delivery of CERs at fixed prices, with **payment on delivery** of the CERs. For buyers, this structure has the benefit of putting as little upfront cash at risk as possible, and ensures payment only will be made when issued CERs are transferred to the buyer – i.e., after the project has received all necessary regulatory approvals. However, because sellers in such transactions typically do not guarantee delivery, buyers face delivery risks, and may receive fewer CERs than the volume they contracted to receive. This could leave compliance buyers in a position of having to purchase compliance instruments in the market at a later date to make up any compliance shortfall, thereby subjecting them to potentially significant **price risk** (i.e., the risk prices will change unfavorably – e.g., the buyer will have to buy higher priced instruments in the market). Thus, while primary CERs are cheaper to buy than secondary CERs, they may have very high replacement costs if they are not delivered. In this respect, primary CERs should be priced at a sufficient discount as compared to secondary CERs so as to compensate for the delivery and credit risks and the associated replacement cost risk associated with primary CERs.

Primary CERs – forward transactions with payment on delivery and variable pricing

Alternatively, CERs may be paid for on delivery, but with **variable ("floating") pricing** rather than fixed pricing. In such cases, prices are typically **linked to an index** (i.e., benchmarked), such as EU Allowance (EUA) prices in the year that the CERs are to be delivered. In general, buyers typically prefer fixed pricing because it avoids future price uncertainties. Earlier in the evolution of the EU ETS, some sellers were particularly interested in "indexing" when there was an expectation that EUA prices would steadily rise over time. Large, unpredictable changes in allowance prices – such as the price drop resulting from the global economic crisis of 2008 and 2009 – illustrate the significant price risks associated with pricing structures that are completely based on floating prices.

In practice, however, sellers often have been interested in a **hybrid pricing structure involving fixed and variable components**. One common structure is to have a minimum (fixed) price, plus a percentage of a future EUA price. This structure has remained popular among many sellers, in that it allows them to benefit from any future increases in EUA prices, but also provides certainty in the form of a minimum price, which is important to obtain financing. From a risk perspective, this structure also has some benefits for buyers. If EUA prices increase significantly, some sellers and their host country governments may choose not to honor their sales contract, known as an **Emission Reduction Purchase Agreement (ERPA**), because once their CERs are issued, they can sell them for a much higher price than was agreed to in the ERPA. Therefore, allowing the seller to capture some of the benefits of rising carbon prices (through the use of hybrid pricing structures) can reduce the risk of a project defaulting. It also

[11] This discussion draws in part from chapter 6 of the United Nations Development Program (UNDP) document "The Clean Development Mechanism – A User's Guide", 2003, http://www.undp.org/energy/climate.htm#cdm, http://www.undp.org/energy/docs/cdmchapter6.pdf.

should be noted that hybrid pricing structures depend on the existence of a reliable market index (e.g., a future price for EUAs on a specific exchange). Such an index may not exist in the early stages of the development of a GHG mitigation program and prior to the emergence of one or more dominant exchanges.

Primary CERs – forward transactions with partial pre-payment

This structure involves buyers providing some **partial up-front payment** to the seller. For projects in need of financing, options include selling equity or debt (discussed below), obtaining a loan from a bank, or obtaining pre-payment from an offset buyer – which is similar to a loan. The up-front payment amount sought by the seller may be the amount needed to cover capital expenditures for the project and project cycle costs (e.g., costs for developing necessary project documentation, and for paying for third-party auditors to perform a required "validation" or "verification" of the project's emissions baseline and projected and actual emission reductions). Thus, the up-front payment represents a source of project finance for the seller. This structure has been particularly important to sellers in the existing carbon market because of the inability of smaller developers to secure bank financing and the lack of standardized financing products. For the buyer, the benefit of pre-payment is that it allows access to a greater selection of projects, because many projects require pre-payment to be implemented. Another benefit of partial up-front payment is that buyers may pay a lower overall price per tonne, in net present value terms, than for many fixed price contracts, because the risk of providing up-front payment is reflected and incorporated into the price per tonne paid by the buyer. (This estimated risk will vary based on the seller's credit risk and project risks.)

The risk of pre-payment is that the loan may not be repaid through delivery of some or all of the contracted offsets. In such transactions, the buyer is exposed to the seller's credit risk, and the various types of delivery risk that can result in under-delivery or non-delivery of offsets. However, these risks can be reduced if the buyer has some recourse available if the loan is not repaid. For example, it is possible to receive guarantees from a local bank working with the project that the upfront payment will be repaid.

Primary CERs – debt and equity

As noted above, projects in need of financing may seek a loan from an investor or may sell an equity share in the project. The benefit of buying debt from a project is the (presumably) high returns that may be obtained, while the risk is the potential the loan will not be repaid, whether in the form of offsets or cash. For most compliance buyers, buying debt from a project may be viewed as too risky and involving too many unknowns with respect to the seller and other participants in project financing, such as a local bank. In addition, compliance buyers in the electric sector may be precluded by state PUCs and internal risk management policies from purchasing debt issued by relatively small, unrated offset project development companies.

Equity investments in projects have proven more attractive to compliance buyers. In particular, certain types of projects, such as wind projects, have attracted equity investments from investors – including electric companies – that have expertise in the technologies employed by the project.

As discussed in Section II, equity investments also may allow buyers to gain the benefit of obtaining emission reductions “at cost,” having (potentially) greater “quality control,” and – depending on the project – the benefit of earning a secondary revenue stream, such as revenue from electricity sales. The risk of equity investment includes various risks associated with the project and other investors in the project, and delivery risks. One way to manage the risk associated with investing in a single project is to invest in a project developer itself that develops several projects in a desired technology category.

It should be noted that the majority of compliance buyers do not purchase debt or equity in projects, but rather prefer to purchase offsets through pay-on-delivery structures. Pre-payments, however, are a form of loan that seems to be more popular with buyers, and can be structured to reduce risks. The challenge for buyers that do not purchase debt or equity in projects is that they may not have access to many potential offset projects and emissions reductions that are available to other buyers who are willing to take debt and/or equity positions.

Secondary CERs – spot transactions, forward transactions, and futures

As noted above a **spot market** currently exists for issued CERs. Buyers can purchase issued CERs on an exchange, and within minutes of paying, will receive issued CERs into their account. The benefit of “spot” transactions is that risks are negligible; the buyer may be exposed to the seller’s and the clearing firm’s credit risk only for the few minutes between payment and delivery. In addition, buying a single year’s volume of CERs in a spot trade provides flexibility with respect to future compliance options and decisions (e.g., the buyer is not locking in a forward stream of reductions that may be subject to delivery risks).[12] The disadvantage of spot transactions is that prices for issued CERs are higher than primary CERs. In addition, using spot market purchases as a primary approach for compliance has the potential disadvantage of creating cash flow problems for buyers, in contrast to forward or futures transactions in which payment is delayed until a future date when the CERs will be needed for compliance. It also should be noted that the spot market is relatively new because only a limited volume of CERs have been issued to date. Spot transactions are not likely to be an available alternative in the early years of an evolving emissions offset market.

“Forward” and “futures” contracts in the CDM market context are analogous to forward and futures in electric power transactions in the wholesale electricity market and transactions in other commodities. For secondary CER transactions, forwards and futures are similar in that both allow a buyer and seller to exchange a fixed volume of secondary CERs against payment at a future date. However, forwards typically are conducted bilaterally or through a broker in a direct OTC trade, while futures are exchange-based and standardized.[13] Forward transactions can be customized, and allow buyers to manage cash flows better (through setting more convenient delivery dates than the standardized dates in futures transactions). Their risk is that the buyer is exposed to credit risk, although the short-term nature of the transaction, from contracting to settlement, reduces the buyer’s exposure. In addition, sellers in such transactions (e.g., banks, energy companies) typically have excellent credit ratings.

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[12] UNDP, “CDM – A User’s Guide”, p. 72, op. cit.
[13] “Technical Aspects of EU Emission Allowances Auctions,” consultation paper for the European Commission, 2009, http://ec.europa.eu/environment/climat/emission/pdf/cons_paper.pdf, p. 98.

In addition, futures transactions on an exchange require buyers and sellers to pay initial and variation “margin” to allow the exchange’s clearing house to execute the contract in case of default by either party.[14] This minimizes delivery and credit risks, but overall costs are higher than in OTC forward transactions. Electric power companies seeking to transact secondary CERs with other electric companies may prefer forwards to futures transactions. As such companies regularly engage with each other in electricity trading, they may be less concerned about each others’ credit risks, and may prefer to avoid margin requirements.

Buying secondary CERs with guaranteed delivery rather than EUAs is worthwhile only if the price spread between EUAs (the compliance value of which is certain and unconditional) and secondary CERs is sufficiently large to outweigh any remaining risk that exists in secondary CER transactions. The price spread exists in large part because there are regulatory imposed limits on CER use for compliance in the EU ETS, which reduces their value relative to EUAs, the use of which for compliance is unconstrained.

Options – calls and puts

Option contracts in offset markets are directly analogous to option contracts on corporate stocks. Buying a call option provides the right – but not the obligation – to buy a pre-determined number of CERs from the seller at an agreed price at a specific time in the future.[15] Conversely, buying a put option provides the right – but not the obligation – to sell a pre-determined number of CERs to the buyer at an agreed price at a specific time in the future. In the case of a call option, if the agreed price (the “strike price”) is attractive to the buyer at the future date, the buyer will exercise the option and buy the CERs. If it is not attractive, the buyer can simply choose not to exercise the option. This flexibility makes options an effective form of insurance to address uncertainties and mitigate risk relating to the volume of compliance instruments that a company may need in the future, as well as price risk. Their risk or downside is simply the cost of buying the option (the “premium”), and the potential that the option will not be exercised. Similar to the secondary and spot market, options tend to become available in more mature markets.

IV. The Roles of Different Entities in the GHG Emissions Offsets Market and Procurement Process

The discussion that follows briefly describes the role of, and highlights differences and distinctions between, different entities that buyers may utilize to procure offsets in the market. These entities are ***project developers***, ***brokers***, ***carbon funds***, ***banks*** and ***exchanges***.

To preface this discussion, it may be useful to consider in general terms how the different entities relate to the primary and secondary CER and options markets.[16] Buyers may procure primary

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[14] Ibid, p. 10.

[15] It should be noted that options are more common in the allowance market than the offsets market.

[16] This paragraph was derived from Caisse des Depots, “Carbon Investment Funds: The Influx of Private Capital,” Mission Climat, Research Report no. 12, November 2007, p. 7,

CERs directly from project developers, through brokers and through carbon funds. The first option is mainly undertaken by large companies that can devote resources to developing expertise in offset procurement. Buyers may procure secondary CERs from banks – which have the risk management expertise and credit rating to provide delivery guarantees – or from project development companies that develop a portfolio of offset projects. Secondary CERs and issued CERs also may be purchased on exchanges. Lastly, option contracts may be purchased over-the-counter through brokers or by using exchanges.

A. Project developers

Offset project developers typically are owners of offset projects, or other entities that intend to develop these projects on behalf of or in cooperation with the owner. Project developers range from very small, local project developers in developing countries with no credit rating to larger project development companies headquartered in industrialized countries. Examples of the latter in existing carbon markets include Camco and Blue Source. The former often need financing to implement their projects – such as upfront payments from a buyer of primary CERs from the project, or bank loans that are secured using the offtake agreement with the buyer.

Larger project development companies may specialize in developing one type of project (e.g., a forestry or land use project, or a wind project) or have a diverse portfolio of projects in a number of countries. Project development companies typically guide the project through the CDM project cycle from submission of a Project Design Document all the way through to issuance of CERs. They then sell the CERs to clients or on the secondary market.[17] Given that their bottom line depends on the number of CERs they can get approved and sell (i.e., "monetize"), project developers are highly exposed to delivery risks, and must carefully manage them. One way to manage these risks is to select projects for which financial returns are expected to be sufficient even if fewer CERs are issued for the project than expected.

B. Brokers

Brokers are a type of intermediary between offset buyers and sellers in primary and secondary CER markets and in the market for options. They play an important role in matching buyers and sellers, providing such key market information as which counterparties are trading and price levels at which it may be possible to transact. In the market for primary CERs, in which each project and contract is differentiated, and little information is otherwise available about project risks and pricing, the informational role of brokers in providing price discovery is important, as is the ability of some brokers to devise and propose non-standardized contract structures where needed to meet buyers' and sellers' needs. Some examples of brokers in the CDM market include Evolution Markets, TFS and CantorCO2e.

In general, the broker identifies projects that meet the buyer's criteria and presents opportunities to the buyer. The broker also may assist in the negotiation of contract terms, but the buyer and the seller undertake the actual contract negotiation (which typically requires the engagement of

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http://www.caissedesdepots.fr/fileadmin/PDF/finance_carbone/etudes_climat/UK/07-11_climate_report_n12_carbon_investment_funds.pdf .

[17] Ibid.

legal, risk management, and commercial resources). For the most part, brokers are paid a brokerage fee based on the value of the transaction.

In the EU, electric companies mainly use wholesale OTC brokers for forward trading of EUAs. Such transactions have defined contracts and delivery dates. Utilities prefer this approach because they already have existing credit relationships with their trading partners through electricity markets, and can avoid paying exchange fees and margin requirements. Retail OTC brokers provide more customized transaction structures and are used by compliance buyers who trade infrequently and seek to cover their emissions shortfall.[18]

In brokered transactions, the buyer typically is responsible for undertaking due diligence on the seller, managing various service providers for the project (e.g., firms that perform monitoring, verification and registration services), and managing contracts to ensure delivery of CERs. Further discussion on these activities is provided in the discussion on carbon funds below.

It is worth noting that brokers may be seen within a broader group of intermediaries linking the sell-side and buy-side of offset markets. One analysis[19] divides such intermediaries into two categories. The first category is intermediaries that source offsets in the primary market through project investments and ERPAs. Some of these intermediaries partner with large financial institutions to benefit from their pools of capital and trading expertise. This group also includes "pure aggregators" who buy primary CERs from many projects in order to resell them. The second category is intermediaries that trade primarily on the secondary market, including trading desks at financial institutions, energy companies and commodity traders. The activities of the second group are considered in the discussion on banks below.

C. Carbon funds

Carbon funds are investment entities that pool capital in order to secure CERs. They may be categorized in different ways. For example, one study[20] makes distinctions between categories of "carbon procurement vehicles" based on whether they are intended exclusively for governments seeking to purchase CERs to meet their Kyoto Protocol emissions targets ("government procurement programs"[21]) or whether they play a key role in the development and active management of projects from start to finish ("project facilities").

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[18] This paragraph was derived from World Bank and International Emissions Trading Association, "State and Trends of the Carbon Market 2006," May 2006, p. 7, http://wbcarbonfinance.org/docs/StateoftheCarbonMarket2006.pdf.

[19] New Energy Finance, "Value Chain Analysis for the North American Carbon Market," Carbon Markets – North America Research Note, pp. 3-6, June 19, 2009 (available by subscription).

[20] Caisse des Depots, 2007, p. 7, op. cit,

[21] The World Bank and the Netherlands were pioneers in the area of carbon funds. The World Bank established the Prototype Carbon Fund in 2000, with participation from 17 companies and 6 governments. Since then the World Bank has established a significant number of funds, some of which are exclusively for governments, others of which are open to private investment (http://wbcarbonfinance.org/Router.cfm?Page=PCF). The Netherlands established the first government purchasing vehicles (CERUPT and ERUPT) in 2001. Other governments also developed offset procurement programs and participated in funds as elements of their strategies to meet their obligations under the Kyoto Protocol and EU ETS.

For the purposes of this paper, we focus on carbon funds that are open to private investment. Within this group, a key distinction is that between "compliance funds" and "return-on-investment" funds. Compliance funds typically aim to provide participants with offsets that they can use to comply with their emission targets under the EU ETS or the Kyoto Protocol. They can provide financing for emission reduction projects through upfront payments, equity investment or forward purchase contracts, using a variety of contractual structures.[22] (More detail on services provided by carbon funds is provided below.) Natsource's Greenhouse Gas-Credit Aggregation Pool (GG-CAP) and the Natsource Carbon Asset Pool (NAT-CAP) are two examples of compliance funds.[23] Other examples include the Multilateral Carbon Credit Fund operated by the European Investment Bank and the European Bank for Reconstruction and Development, and the KfW Carbon Fund.[24] In addition, the World Bank has a wide range of compliance funds and other funds, including the first carbon fund (the Prototype Carbon Fund, which included private sector participants and governments), funds created to meet individual governments' compliance needs (e.g., Spain, the Netherlands, Italy), and funds focusing on investments in particular project types (e.g., the BioCarbon Fund, the Community Development Carbon Fund). "Return-on-investment" funds attempt to create financial returns based on investments in emission reduction projects and subsequent transactions. Examples of such firms with "return-on-investment" funds include Climate Change Capital, Trading Emissions and Natixis.

"Buyer" companies participate in compliance funds in order to procure a diverse set of carbon offsets – created across different locations and using different technologies/activities – which they can use for compliance. By pooling capital, such funds are able to develop, and/or purchase the offtake from, large-scale projects to which they would otherwise not have access.[25] Typically, only very large companies would be able to access such projects. Pooling capital also allows for the pooling and sharing of various project expenses, creating the potential for cost savings on fixed-cost expenses. Unlike some individual buyers, compliance funds can provide upfront financing, in exchange for which the seller typically provides a lower price per ton for reductions. They also allow buyers to benefit from the fund manager's expertise.[26] Similar to other asset managers, carbon fund managers can be compensated through a management fee, performance-based compensation, and/or other fees.

In addition to pooling capital, carbon funds generally act as turnkey service providers for offset procurement, often playing a role in originating, creating and managing delivery of offsets. In this respect, they differ from other intermediaries, which generally do not provide a full range of analysis, due diligence, auditing, contract management and other services. More fundamentally, funds represent the buyer. To align interests, in some cases, the fund manager has money

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[22] Caisse des Depots, 2007, p. 6, op. cit.
[23] GG-CAP was the world's largest private sector compliance fund at close in October of 2005 with approximately €500 million in commitments, and included participants from Europe, Japan and Canada. NAT-CAP was launched in June of 2008 and was Natsource's second fund dedicated to helping clients in Europe to comply with emissions targets under the EU ETS.

[24] KfW is a bank owned by the German government.

[25] Caisse des Depots, 2007, p. 7, op. cit.

[26] Ibid.

invested in the fund along with the buyers. In contrast, brokers may represent the buyer or the seller, or may introduce the buyer and seller, in which case the broker represents the trade generally. To illustrate how a carbon fund's services may differ from services provided by other intermediaries, the following discussion uses Natsource's services for carbon fund participants as an example. (In practice, specific services offered by specific carbon funds and intermediaries may differ from those described here.)

At the project identification stage, the carbon fund manager and the intermediary, such as a broker or bank, both identify projects that meet the buyer's (or fund's) criteria. The fund manager may undertake due diligence, which includes pre-screening projects, assessing the counterparty's ability to deliver emission reductions, and estimating the volume of reductions to be delivered. In brokered transactions, buyers may undertake these forms of due diligence.

At the project structuring and financing stage, the fund manager generally develops and negotiates all purchase and sales contracts, which can be informed by analysis it has undertaken on market pricing and delivery risk. Brokers may assist in the negotiation of contract terms but the buyer and seller typically are the entities primarily responsible for negotiating contracts.

At the portfolio development and management stage, the fund manager may work with the seller to bring a project through the regulatory process to create offsets. To achieve volume and cost objectives, the manager generally manages contracts over time. Contract and portfolio management activities include conducting project audits, providing ongoing assessments of the seller's credit and collateral and the project's delivery risks, and diversifying and rebalancing the fund's project portfolio as necessary to meet overall delivery and timing objectives. Buyers are likely to take on a more active role in managing contracts to ensure delivery, and managing service arrangements for ongoing audit and analysis in transactions in which brokers and other intermediaries play a role.

At the delivery stage, the fund manager typically distributes offsets directly into fund participants' compliance accounts. Brokers may not work with the seller to arrange for delivery. Lastly, the manager frequently manages service providers responsible for the creation and management of offsets, including legal services necessary for contracting, and monitoring, verification and registration services. The manager often also handles receivables, payables and accounting. These services are generally not provided by intermediaries.

D. Banks

After the EU ETS and CDM markets began to mature, financial institutions such as large international banks became engaged in these markets and established carbon trading desks similar to other trading desks, which provide a range of trading services for their clients and also make investments and trades for their own accounts. (Examples of banks that participate in the CDM market include Barclays, JPMorganChase, Merrill Lynch, and BNP.) A number of banks have developed portfolios of CERs, either by purchasing primary CERs, investing in underlying projects or acquiring carbon aggregators. In general, these banks leverage their risk expertise by assessing projects and the delivery risk, purchasing primary CERs early in the project development cycle to secure more favorable pricing, managing delivery risks on their portfolio of projects, and then selling CERs at a premium as secondary CERs and providing a delivery guarantee. This provides buyers with an instrument that has very limited risk (i.e. exposure to credit risk, but the bank's credit rating is typically very high). However, secondary CERs are priced higher than primary CERs, and at a relatively small discount to EU Allowances, which have definite compliance value.

As a group, financial institutions account for a large share of trading volumes on exchanges.[27] (These volumes are dominated by EU Allowance transactions.) Some investment banks undertake speculative trading and serve as primary brokers for hedge funds.[28] Banks take advantage of arbitrage and risk hedging opportunities in carbon markets through various transactions, not limited to options and swaps between CERs and EU Allowances or Emission Reduction Units (ERUs) generated by JI projects.[29] In general, speculating on carbon is similar to speculating in other commodity markets. Trading strategies are based on fundamental and technical analysis that allows the participant to form a view of whether the commodity is undervalued or overvalued, and to take a "long" or "short" position accordingly.

Industrial companies in the EU ETS, which received generous free allowance allocations to address competitiveness concerns and faced limited emissions shortfalls, have often used banks to manage their allowance purchases and sales because these companies have limited trading experience.[30] Sellers in CDM markets also use banks for such purposes as obtaining loans against future carbon credit proceeds in forward purchase contracts (i.e., ERPAs with payment on delivery).[31]

E. Exchanges

Exchange trading has become the largest source of EU Allowance trading volumes, growing from zero in 2005 to approximately 50% of transactions as of early 2010.[32] Exchanges have offered standardized contracts for trading in secondary CER futures and options since approximately 2008.[33] More recently, some exchanges have started to offer spot trading of issued CERs. Other exchanges also provide futures and derivatives trading in electricity and other commodities. Exchanges trading EU allowances and CERs include BlueNext, the European Climate Exchange (ECX), and the European Energy Exchange (EEX).

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[27] World Bank and International Emissions Trading Association, "State and Trends of the Carbon Market 2006," May 2006, p. 7, op. cit.

[28] Ibid.

[29] World Bank, "State and Trends of the Carbon Market 2008," May 2008, pp. 8, 65, http://wbcarbonfinance.org/docs/State_Trends_FINAL.pdf.

[30] World Bank and International Emissions Trading Association, "State and Trends of the Carbon Market 2006," May 2006, p. 7, op. cit.

[31] World Bank, "State and Trends of the Carbon Market 2008," May 2008, p. 64, op. cit.

[32] World Bank, "State and Trends of the Carbon Market 2010," May 2010, p. 9 (figure 3), http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/ENVIRONMENT/EXTCARBONFINANCE/0,,contentMDK:22592488~menuPK:5221277~pagePK:64168445~piPK:64168309~theSitePK:4125853~isCURL:Y,00.html.

[33] World Bank, "State and Trends of the Carbon Market 2008," May 2008, p. 66, op. cit.

As noted earlier, exchanges trade a standardized commodity. A company must be a member of an exchange (and pay the entry fee) to be able to trade over an exchange. Exchanges are typically used by firms that trade large amounts, such as energy companies, banks, other financial institutions, and speculators, since they can amortize the costs of joining the exchange and meeting margin requirements through frequent transactions. In exchange-based transactions, the counterparty is the exchange's clearing entity; if there is a default, the clearing entity is held responsible. This eliminates credit concerns in secondary CER and other transactions, which is an advantage for firms that do not have established credit relationships with trading partners (i.e., firms other than utilities).

V. Compliance Buyers' Strategies for Procuring Offsets, Internal Structures, Required Resources and Expertise

Building on the discussion in Sections III and IV regarding the different transaction structures and entities involved in offset procurement, the following discussion provides some more specific examples of how compliance buyers in the EU ETS have procured offsets to date. It also considers the types of internal structures, resources and expertise that can be involved in procuring offsets, depending upon the particular procurement strategy that is adopted.

A. Compliance buyers' priorities and strategies for procuring offsets

As suggested by the discussion in Section III, primary CERs (and to a lesser extent, secondary CERs) provide an opportunity for compliance buyers to meet emissions targets at a lower cost than is likely to be possible by purchasing emission allowances such as EUAs in the market, or by implementing internal abatement measures (in many cases). In the EU ETS, "covered" installations can use CERs and ERUs (from JI projects) for compliance up to a certain limit. In Phase 2 of the program (2008-12), this limit is established as a percentage of an installation's allocation (and differs across EU Member States and sectors). Utilities can use CERs/ERUs to partially or entirely cover their emissions shortfall, depending on their allocation and assigned CER/ERU import limit.[34]

For compliance buyers, options for procuring offsets include buying offtake from projects through direct negotiations with project developers (which calls for significant internal expertise and resources), the use of a broker, or participation in a carbon fund); buying secondary CERs through brokers or exchanges; investing directly in projects to secure offsets (i.e. equity investments); buying debt in projects to secure offsets (although this is not common); developing internal (i.e., a company's own) offset projects for compliance use; and/or establishing a business to develop internal projects for compliance use and to sell offsets to the market.

[34] Due to the existence of these usage limits, and instances where an electric utility's or another entity's compliance shortfall exceeded its CER/ERU limit, companies have engaged in swapping secondary CERs for EUAs from entities that have not yet met their CER/ERU limits. Such swaps may be financially attractive for industrial entities that may have surplus EUAs and sufficient headroom for their CER/ERU limit. Banks and financial institutions have served as intermediaries in such transactions. Some utilities that have well-established relationships with industrials have entered into these swaps directly with industrial installations.

For EU ETS firms, the choice of strategy in procuring offsets has varied depending on the characteristics of these firms and their compliance requirements, in addition to their specific perspectives on and goals in participating in the CDM market. More specific examples of compliance buyers' priorities and strategies for procuring offsets follow.

1. Power sector and large, multinational industrial firms

The EU ETS imposed the largest emission reduction burden on the electric power sector as compared to other economic sectors covered by this CO_2 cap-and-trade program. As a result, the power sector has been perhaps the largest buyer of both EUAs and offsets (although the rise of speculation in carbon markets by financial institutions and hedge funds may have displaced the power sector as the largest buyer).[35] In the EU, electric companies have established carbon trading desks that trade EUAs daily alongside electric power, gas and coal. Typically, this trading activity is closely coordinated with daily power dispatch and longer term fuel procurement decisions. Emissions are forecasted based on generators' schedule to produce electricity throughout the year, and initial allowance allocations are pro-rated by month according to that schedule to estimate how many allowances must be purchased to cover the estimated short position. When utilities enter into forward contracts to sell electricity throughout the year, they typically hedge the emissions resulting from power sales by buying EUAs to cover the associated estimated short position.

Given that buying CERs and ERUs can be less costly (on a risk-adjusted basis) than buying EUAs, they have been an important component of electric company compliance strategies in the EU. Electric companies estimate the amount of "firm" CERs they have contracted for (i.e., the amount they expect to be delivered, after discounting for risk) and, as with EUAs, they pro-rate it through the year based on their generators' schedule to run twelve months forward.

Electric power companies developed and implemented strategies around the principle of diversification, participating in both the allowance and offset markets and "mining" their own assets for internal GHG emission abatement opportunities. They also diversified in terms of how they procured CERs. In many cases, electric companies have combined several of these strategies in a comprehensive approach.

Many electric companies enter into bilateral contracts to buy offsets directly from project owners or developers. These purchases vary in size, scope and structure, with most transactions requiring significant legal, financial, and regulatory expertise. Companies also purchase offsets indirectly through brokers and exchanges. These purchases may include forward purchases of multi-year streams of offsets or spot purchases of issued offsets or secondary offsets.

For longer term procurement, several electric companies joined carbon compliance funds (described above) including Natsource's two compliance funds. Others joined one or more World Bank funds or the Multilateral Carbon Credit Fund operated by the European Investment Bank and the European Bank for Reconstruction and Development. For example, Endesa (a

[35] The World Bank notes that in the carbon market, "The bulk of activity now comes from volatility and other relative value trades rather than asset-backed trades (i.e., financial and technical trades now account for a greater portion of market activity than do trades for compliance purposes)." World Bank, "State and Trends of the Carbon Market 2010," May 2010, p. 16, op. cit.

large Spanish electric utility) joined the World Bank's Spanish Carbon Fund, and RWE (a large German electric utility) joined the World Bank's Prototype Carbon Fund.

Instead, or in addition, some electric companies operate proprietary carbon procurement initiatives. For example, in addition to joining the Spanish Carbon Fund and Natsource's GG-CAP, Endesa launched its own carbon procurement fund, the "Endesa Climate Initiative." Similarly, Electricite de France launched a €300 million (US $390 million) carbon fund. Other companies like Electrabel, Enel and RWE created corporate divisions to develop offset projects to complement their core businesses and expand in countries in which they operate or are entering.

Larger industrial companies, including some multinationals (e.g., Holcim and Lafarge in the cement sector) that found themselves to be very "short" of emissions allowances or offsets followed a similar approach. They developed their own businesses consistent with their business expansion in CDM or JI jurisdictions, and their objective was to develop project types consistent with their core business. Some opted always to use their CERs from internal projects for compliance use, while others considered on a case-by-case basis whether the optimal use for internally developed CERs was for compliance or external sale.

2. Industrial firms

Most of the industrial sector in Europe received generous EUA allocations to address concerns regarding the sector's potential exposure to international competition, and potential competitiveness impacts of emission reduction requirements. As a result, many firms' compliance shortfalls have been small, and some actually have EUA surpluses. While large multinational industrial companies typically have their own carbon procurement teams, many smaller, less exposed companies do not.

Many industrial firms have limited or no experience in energy markets and with trading. They view emissions trading as peripheral to their business, and may not have the internal resources and expertise to take risks through trading. As a result, industrial sector participation in the carbon market to date generally has been limited.[36] Many seem to have followed "passive" trading strategies, in which they participate on a "one-off" basis, seeking only to meet compliance requirements at the compliance deadline, without significant concern for minimizing their exposure to price risk. This approach is consistent with reports that industrial firms prefer to purchase secondary CERs with delivery guarantees.[37] To the extent they have surplus allowances, industrial firms generally have not sold them in the market prior to knowing their

[36] In recent years, trading activity by industrials increased significantly, but for reasons other than developing a more active compliance strategy. The World Bank notes that EUA trading activity "picked up dramatically in the second half of 2008, peaking in early 2009, during a particularly strong EUA sell-off by industrials looking for liquidity in a tighter credit environment. They sold mostly on the spot market – which saw a dramatic increase in activity and broke daily and monthly records for traded volumes during that period. This is reflected in market data which shows that spot transactions accounted for only 1% of all transactions in the first half of 2008, rising to 7% in the third quarter and 19% in the fourth quarter (and accounting for 36% of all transactions in December 2008 alone)." World Bank, "State and Trends of the Carbon Market 2009," May 2009, p. 5, op. cit.

[37] World Bank, "State and Trends of the Carbon Market 2008," May 2008, p. 35.

allowance submission requirements (i.e., GHG emissions) for the year.[38] Some do not sell them at all, preferring instead to bank them into Phase 3 of the EU ETS (2013-20), when GHG reduction targets and allowance allocations will become more stringent.[39] As noted above, some industrial firms use banks to sell their allowance surpluses and to address their compliance shortfalls due to their lack of trading experience, difficulties in obtaining credit arrangements (which is required in brokered transactions), and the costs of participating in an exchange.

3. Oil and gas companies

In general, oil and gas installations' compliance-related buying and selling of offsets has been relatively limited given their relatively generous allowance allocations in 2008-12 and their small compliance shortfalls. Their participation in the market mostly has been limited to selling surplus allowances a few times a year. However, a few oil and gas compliance participants like BP and Shell set up carbon desks to manage their speculative trading in addition to compliance transactions, and are active participants in the offset market.

B. Internal structures, required resources and expertise

The level of internal resources and expertise required to procure offsets in the market depends on the procurement strategy adopted by the company. As discussed above, electric companies and some large, multinational industrial firms launched their own divisions to develop offset projects internally, joined carbon funds and in some cases created their own carbon funds. In contrast, small industrial firms that had small compliance shortfalls or allowance surpluses, made a minimal number of transactions (often using banks) simply to ensure compliance, tended to favor secondary CERs with guaranteed delivery, and didn't attempt to minimize price risk. These approaches entail very different levels of internal structures, resources and expertise.

For firms in the electric power sector and other sectors that pursue a diversified approach to procuring offsets – including developing offset projects internally, procuring offsets in the market directly with sellers, through brokers and/or participating in carbon funds – expertise (and associated internal structures and functions) is required in a number of key areas, including but not limited to the following:

- **Offset pricing and delivery risk**. Expertise in this area requires a thorough understanding of market prices, project delivery risks for various types of projects and countries, and contract structures that assign different levels of risk to buyers and sellers. Having expertise in this area is important for participating in both brokered transactions and participating in a carbon fund, although carbon funds may offer more market and risk analysis and due diligence than brokers, and therefore may be attractive to firms that do not have such expertise. It also is clearly important for firms that seek to sell any offsets they develop internally in the market.

- **Legal**. Offset-related functions handled by a company's legal department include structuring and negotiating ERPAs with sellers in brokered transactions, and

[38] By March 31 each year, EU ETS installations must verify and report total emissions for the preceding calendar year, and must surrender allowances to cover those emissions by April 30.

[39] World Bank, "State and Trends of the Carbon Market 2010," May 2010, p. 11, op. cit.

understanding a carbon fund's approach to these issues as well as the terms for participating in the fund.

- **Accounting**. Accounting expertise is required to address the tax and accounting issues that arise in offsets procurement and sales, including marking-to-market and accounting issues associated with handling financial derivative transactions.

Managing offset delivery and associated risk management. Other than carbon funds, most intermediaries do not manage the delivery of offsets. Thus, buyers generally need to manage this process – which can be time consuming and should not be considered automatic – and implement associated risk management measures. One fundamental and time consuming risk management measure is to "stay in touch" with the project by undertaking site visits and ongoing monitoring over the course of the project. Other risk management measures include various measures to reduce risk, transfer risk, and accept risk. Some examples of measures that a buyer can implement to reduce risk include: (i) implementing credit limits on sellers, both in terms of volume and duration; (ii) requiring that the seller provide collateral, which can be in provided in various forms; and, (iii) reducing the concentration, in a buyer's offsets portfolio, of offsets from a specific geographic location, using a specific technology, or involving a specific seller. Some examples of measures to transfer risk include swapping primary CERs for less risky instruments, purchasing financial guarantees that transfer delivery risk to a third party, or entering into "interruptible buyer contracts," in which the buyer may cancel the contract without penalty under certain circumstances. Lastly, some examples of measures to accept risk include: (i) establishing reserve margins (e.g., a 20% reserve margin) for a portfolio of primary CERs, and "overbuying" primary CERs accordingly; and (ii) incorporate "default recovery" provisions in the ERPA.

- **Screening, identifying and developing offset projects "in house."** Selecting and developing an offset project requires significant expertise in the technology utilized in the project, and in the economics and delivery risks associated with the project. To identify the most attractive projects, firms may undertake, or hire a third party to undertake, a comprehensive assessment of internal abatement costs. For example, they may develop standard approaches across business units for preparing facility-wide marginal abatement cost (MAC) curves and hurdle rates for energy efficiency projects to assess potential emissions abatement projects in their own assets. To bring a project through the CDM cycle, it is necessary to have expertise in the CDM project development "cycle" and regulations and in preparing a Project Design Document (PDD), or companies can hire firms with such expertise. It is also important to hire a third party project auditor (referred to in the CDM as a "Designated Operational Entity") that has expertise in *validating* and *verifying* offset projects utilizing the specific technology.

- **Additional functions for firms developing offsets "in house" either for compliance or for sale in the market**. These functions, which may be housed in an "in house" carbon fund or trading desk, may include:
    - Formulating corporate-wide compliance strategy (based on a consideration of projected emission shortfalls at the business-unit-level, the corporate-wide MAC curve, external market prices, and internal CER prices).

- Considering the potential transaction cost savings and risk management benefits of using internal CERs for compliance.
- Buying internal CERs from and transferring them between business units;
- Making internal CERs available for sale to internal business units that face a compliance shortfall;
- Selling internal CERs in external markets (if they are not purchased internally or banked);
- Banking internal CERs, where this is deemed advantageous; and,
- Providing regulatory advice and other services to business units to assist them with successfully moving offset projects through the regulatory approval process.

VI. Options for Financing Offsets Projects and Managing Risk

As discussed in Sections III and IV, different options for financing offsets projects, transaction structures, and procurement approaches offer different benefits and risks. The discussion that follows builds on those concepts and provides some broader perspectives on options for managing risk for compliance buyers.

An initial caveat is that the topic of risk management in the context of an entity's compliance obligation goes beyond actions (and associated risks) relating to offset procurement or the development of internal offset projects. It also includes purchasing emission allowances and implementing cost-effective internal emission reductions. For example, the need to manage price risk and timing risk (i.e., having an unexpected compliance shortfall near the compliance date, and needing to purchase compliance instruments at unfavorable prices) applies equally to allowance purchases and offset purchases. Notwithstanding this point, for the purposes of this paper, we focus only on risk management with respect to offset procurement.

In general, there is a fairly limited set of tools available to manage delivery risk on primary CERs. In an offsets market that is not mature, and in which there is little or no experience with securing regulatory approval of offsets, there is significant delivery risk with primary offsets, and very few options for managing delivery risk exist. Secondary offsets with guaranteed delivery and options likely will not be available in an immature market. Only buyers with expertise in assessing delivery risk, pricing and contracting can effectively manage delivery risk at this stage in the market (see discussion carbon funds and portfolio diversification below). While immature offset markets likely will pose challenges for most buyers, sophisticated buyers should be able to identify and take advantage of opportunities to purchase offsets at favorable prices (on a risk-adjusted basis).

In a more mature market, there are more options for buyers to manage delivery risks. Buyers that wish to avoid delivery risks can purchase secondary offsets with a delivery guarantee. However, since secondary CERs are priced at a premium to primary CERs, this approach eliminates much of the cost savings associated with purchasing offsets. In addition, there is still credit risk associated with forward transactions of secondary CERs, but these are generally very limited as the seller is typically a bank or another highly creditworthy counterparty. In a mature market, as in the CDM market, it may be possible to purchase call options, thereby locking in a price and reducing price risk. This is an effective approach, but comes at the cost of the option premium. In addition, options on primary CERs do not address the problem of delivery risk. Some market observers also point to insurance products that have been offered by insurance companies over the course of the development of the CDM market. However, to date there has not been an insurance product that has attracted significant interest from the market, likely because they have been too costly.

For buyers that seek to maximize the potential cost savings associated with offsets as a compliance tool, the only way to manage delivery risk is to obtain a diversified portfolio of primary CERs. The portfolio should be diversified such that exposure to delivery risk associated with any particular technology or country is limited. For smaller buyers, the simplest way to obtain the benefits of a diversified portfolio is to participate in a carbon fund that seeks to develop such a portfolio. Funds may have the necessary size to be able to diversify their offset project portfolio, and (generally) the necessary expertise in delivery risk assessment, risk management, and portfolio development to determine effective approaches to reduce overall delivery risk through diversification.

Large buyers with sufficient resources can seek to diversify in two ways: (i) diversifying their portfolio of primary CERs to reduce overall delivery risks, and (ii) diversifying their approaches to procuring offsets. The latter form of diversification helps reduce the buyers' exposure to underperformance by any one particular source of offsets. As noted in Section IV, some large buyers procure offsets through a combination of approaches, including: (i) developing internal offset projects (which offer the benefit of direct control over the project and the ability to more fully understand its delivery risks and reduce them); (ii) procuring primary offsets directly from project developers, and/or through brokers; and, (iii) participating in one or more carbon funds.

Another approach to managing delivery risk is to focus on project types that have very low delivery risk to date. For example, in the CDM, industrial gas projects such as hydrofluorocarbon (HFC)[40] and nitrous oxide (N_2O)[41] destruction projects have experienced over-delivery of emission reductions relative to the volume initially estimated by project developers in their Project Design Documents.[42] In future offset markets, firms with expertise in assessing delivery risks may be able to identify project types with low delivery risk. However, elimination of delivery risks and uncertainties may not be possible, particularly if the regulatory regime can change rules and methodologies after investment decisions have been made. For this reason, diversification remains the most effective approach to managing delivery risk.

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[40] Destruction of HFC-23 waste streams produced during HCFC-22 production.

[41] Destruction of N_2O formed as a by-product of the production of adipic acid or nitric acid.

[42] It should be noted that these project types have faced political opposition, despite their having been approved previously by the CDM Executive Board. In addition, under a potential future U.S. offset program, HFC and N_2O destruction activities may not be eligible to generate offsets because industrial gas emissions may be covered under a separate cap-and-trade program.