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PROJECT

«Creation of technical, legal and financial conditions for wide scale recovery and utilization of flared and vented associated gas in Azerbaijan»

Manual for project owners and developers on how to attract CDM financing for associated gas flaring/venting reduction activities

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1 Introduction

This manual intends to provide specific and detailed guidance to project developers on how to identify, develop and attract carbon financing to flaring and venting reduction projects. We understand that carbon financing may only contribute a relatively small amount to the overall project financing. However, in some cases when capital expenses are not high monetization of emission reductions could contribute fair value to the project completion.

In the current manual we will start from the review of general international situation with CDM projects in the area of venting and flaring prevention. This review will cover approved and pending baseline and monitoring methodologies for venting/flaring as well as the projects already registered or undergoing validation. The review will also include some suggestions about the extension of existing methodologies to enable the inclusion of more project opportunities.

Following this the manual discusses how the conventional project financing via loans and equity could be supplemented by carbon financing. We discuss the entire CDM project cycle from project initiation to registration, monitoring and issuance of carbon credits. The manual will pay special attention to carbon contracting, which is key to monetization of CDM carbon benefits.

We hope that this manual will be quite useful to both existing and new flaring/venting prevention project developers in Azerbaijan.

2 Overview of CDM projects in the area of associated gas (AG) flaring/venting prevention

2.1 Background on Clean Development Mechanism

Clean Development Mechanism (CDM) is an arrangement under the Kyoto Protocol allowing industrialized countries with a greenhouse gas reduction commitment (called Annex B countries) to invest in projects that reduce emissions in developing countries as an alternative to more expensive emission reductions in their own countries. A crucial feature of an approved CDM carbon project is that it has established that the planned reductions would not occur without the additional incentive provided by emission reductions credits, a concept known as "additionality". Presumably, the CDM allows net global greenhouse gas emissions to be reduced at a much lower global cost by financing emissions reduction projects in developing countries where costs are lower than in industrialized countries. However, in recent years, criticism agains the mechanism has increased (http://en.wikipedia.org/wiki/Clean_Development_Mechanism).

The CDM is supervised by the CDM Executive Board (CDM EB) and is under the guidance of the Conference of the Parties (COP/MOP) of the United Nations Framework Convention on Climate Change (UNFCCC). The EB via its Methodological Panel has great level of control over the entire CDM process, from project registration to issuance of Certified Emission Reductions (CERs). Thus project developers and buyers of CERs in Annex I countries could never be sure that their project will deliver a planned volume of CERs due to potential CDM EB interventions.

The purpose of the CDM was defined under Article 12 of the Kyoto Protocol. Apart from helping Annex B countries comply with their emission reduction commitments, it must assist developing countries in achieving sustainable development, while also contributing to stabilization of greenhouse gas concentrations in the atmosphere. To prevent industrialized countries from making unlimited use of CDM, the framework has a provision that use of CDM be 'supplemental' to domestic actions to reduce emissions. This wording has led to a wide range of interpretations - the Netherlands for example aims to achieve half of its required emission reductions by CDM.

The CDM gained momentum in 2005 after the entry into force of the Kyoto Protocol. Before the Protocol entered into force, investors considered this a key risk factor. The initial years of operation yielded fewer CDM credits than supporters had hoped for, as Parties did not provide sufficient funding to the EB.

The rulebook for the CDM set forth in the Marrakesh Accords focuses on projects that reduce emissions. Rules have been developed for including afforestation and reforestation activities in the CDM for the first commitment period at COP 9 (Milan, December, 2003).

The CDM is expected to generate investment in developing countries, especially from the private sector, and promote the transfer of environmentally sound technologies in that direction. However, the finance and technology transfer commitments of Annex II Parties under the Convention and the Kyoto Protocol are separate and remain valid.

Furthermore, public funding for CDM projects must not result in the diversion of official development assistance. CDM projects must have the approval of all Parties involved, and this may be gained from designated national authorities (to be set up by each Annex I and non-Annex I Party). CDM projects must lead to real, measurable and long-term benefits related to the mitigation of climate change, in the form of emission reductions or greenhouse gas removals that are additional to any that would have occurred without the project

The CDM EB supervises the CDM, operating under the authority of the COP/MOP (a role being performed by the COP until the COP/MOP meets). Key initial tasks of the EB were to develop simplified procedures to encourage small-scale projects, notably for renewable energy and energy efficiency activities, and to accredit independent organizations, known as designated operational entities, pending their formal designation by the COP or COP/MOP. These operational entities play an important role in the CDM project cycle, which is described below. CDM projects must be based on a project-specific, transparent and conservative *baseline* (the starting point for measuring emission reductions or removals), and must have in place a rigorous monitoring plan to collect accurate emissions data. The baseline and monitoring plan

must be devised according to an approved methodology. If the project participants wish to use a new methodology, it must be authorized and registered by the executive board.

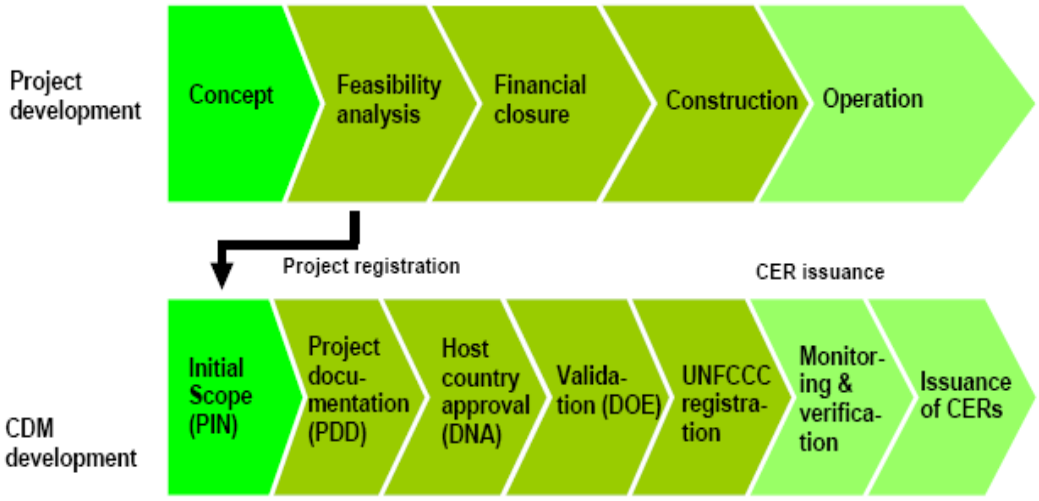
The COP7 decisions (Marrakesh Accords) specify three requirements for a non-Annex I country to be eligible to host a CDM project:

- The country must be a Party to the Kyoto Protocol;
- Participation in the CDM project must be voluntary; and
- The country must have designated a national authority for the CDM

In addition to the aforementioned requirements, CDM projects must assist host countries in achieving sustainable development. However, it is the host Party's prerogative to decide whether a CDM project does indeed provide this benefit. The designated national authority is the entity that officially confirms that the host country has decided that the project will contribute to national sustainable development.

In order to implement a CDM project, the project participants must prepare a *project design document,* including a description of the baseline and monitoring plan to be used, an analysis of environmental impacts, comments received from local stakeholders and a description of the additional environmental benefits that the project will generate. It is assumed that the *national approval* of a CDM project would occur afterwards to ensure that the proposed project lies within the national development agenda. Typical CDM project cycle is illustrated in the Figure 1 below (www.unfccc.int/cdm).

Figure 1: Schematics of CDM Process.



Designated Operational Entity (DOE) will then review the PDD and, after providing an opportunity for public comment, decide whether or not to *validate* it. At this stage project is judged against a set of requirements that includes:

- Conformation to the country eligibility rules;
- Summary of local stakeholder comments and a report on how comments were addressed;
- Analysis of the environmental impacts of the proposed project activity;

• Demonstration of additionality of emission reductions resulting from the project;

• Use of baseline and monitoring methodologies that conform to those approved
by the executive board;

• Provisions for monitoring, verification and reporting; and

• Conformation to all relevant decisions of the COP and the COP/MOP

During validation, the operational entity must receive written approval of voluntary participation from both project participants (Annex I and non-Annex I countries). This approval is issued by the designated *national authority* of each project participant. Also the operational needs to have a confirmation by the host Party that the project assists it in achieving sustainable development. The operational entity shall also receive comments on the project design document from Parties, stakeholders, and UNFCCC-accredited non-governmental organizations, and must explain how it has taken these comments into account in its project evaluation

Project *registration* is under the authority of the CDM EB, and is a prerequisite for verification, certification, and issuance of CERs. If DOE determines the proposed project activity to be valid (based on the information provided, and taking into account the comments received), it submits a request for CDM project registration to the executive board. Registration is deemed final 8 weeks after the executive board's receipt of the request for registration, unless a Party involved in the project, or at least 3 members of the executive board, requests a review of the project. If, after the review, the project registration is declined, the executive board will provide comments to the project participants and public explaining the reasons for non-acceptance. A proposed project that is not accepted for registration may be reconsidered for validation and registration after appropriate revisions have been made (http://cdmrulebook.org/109).

The *monitoring* of a specific CDM project is used to ensure that the project-based emission reductions are real and measurable. An approved monitoring methodology must be used by project participants. Also, the project design document must show that there are provisions for a monitoring plan and that the methodology, data and supporting documents will be available for verification. Monitoring can be performed by either project proponents or a third party and result in the monitoring report

The *verification* of a project activity is the periodic independent review of the project by the designated operational entity. This occurs after the project has been registered and initiated, including an ex *post* determination that the monitored GHG reductions of the project have indeed taken place. A designated operational entity may undertake a number of activities to confirm emission reductions, including conducting site visits, reviewing monitoring methods, analyzing monitoring data, and interviewing project participants and local stakeholders. The designated operational entity will produce a verification report, and based on this report, *certify* in writing that the project activity achieved the verified amount of emission reductions during the specified period, and that those emission reductions would not have occurred in the absence of the project. The verification and certification report are to be made available to the public

The verification and certification report constitutes a request to the executive board for *issuance of CERs* equal to the verified amount of GHG reductions. Issuance is considered final 15 days after receipt of the request for issuance, unless a Party involved in the project, or at least three members of the executive board, requests a review of the project. If, after the review, CER issuance is declined, the executive board will provide comments to the project participants and the public explaining the reasons for non-issuance. If the executive board approves issuance, the CDM registry administrator will issue the specified quantity of CERs into the account of the executive board in the CDM registry. Then, the CDM registry administrator will promptly forward a share of the CERs for administration expenses and adaptation costs to appropriate accounts of the registry, and forward the remaining CERs to the registry accounts of appropriate Parties and project participants.

Once a project is up and running, participants will monitor the project. They will prepare a monitoring report including an estimate of CERs generated by the project and will submit it for verification by an operational entity. (To avoid conflict of interest, this will usually be a different operational entity to that which validated the project design document.) Following a detailed review of the project, which may include an on-site inspection, the operational entity will produce a verification report and, if all is well, it will then certify the CERs as legitimate. Unless a project participant or three executive board members request a review within 15 days, the executive board will issue the CERs and distribute them to project participants as requested.

The CERs generated by projects are subject to a levy, termed the "share of the proceeds". Two percent of the CERs of each project are be paid into a newly created *adaptation fund* to help particularly vulnerable developing countries adapt to the adverse effects of climate change (projects in least developed countries are exempt from this part of the levy in order to promote the equitable distribution of projects). Another percentage is to cover the CDM's administrative costs.

The executive board of the CDM maintains a *CDM registry,* which contains CER accounts for non-Annex I Parties participating in the CDM. It is assumed that the national CDM authority would also keep such a registry for local CDM projects.

2.2 Approved and pending CDM Methodologies in Flaring/Venting Area

According to the most recent UNFCCC CDM information, the following baseline and monitoring methodologies for flaring/venting reduction CDM projects has been approved by the CDM EB to date:

1. AM 0009v4 - Recovery and utilization of gas from oil wells that would otherwise be flared or vented
2. AM 0023v2 - Leak reduction from natural gas pipeline compressor or gate stations
3. AM 0037- Flare (or vent) reduction and utilization of gas from oil wells as a feedstock
4. AM 0055 - Baseline and Monitoring Methodology for the recovery and utilization of waste gas in refinery facilities

5. AM 0077 - Recovery of gas from oil wells that would otherwise be vented or flared and its delivery to specific end-users.

All these methodologies are potentially applicable to on- and off-shore oil and gas production, processing, storage and transmission facilities in Azerbaijan.

The most tested is the AM 0009v4, which have 6 registered projects under CDM. The number of projects registered under AM 0037 and AM 0023v2 is two and one, respectfully. No projects have been registered yet under AM0055 and AM0077.

2.3 On-going and Potential CDM Projects

2.3.1 Overview of all CDM flaring/venting projects

According to the latest RISO CDM pipeline (http://cdmpipeline.org/cdm-projects-type.htm) most projects are under development belong to AM0009 group followed by AM0037 and AM0023. The rest venting/flaring AMs remain largely untested.

Table 1: Statistics on venting/flaring CDM projects registered and under development

Approved Methodology	*Number of Projects (registered/total)*	*Size Range (ktCO2e) for registered projects (ktCO2e/year)*
AM 0009v4	6/22	53 082 – 2 626 735
AM 0023v2	1/4	339 197
AM 0037	2/6	8 793 – 97 740
AM 0055	0/4	Na
AM 0077	0/0	Na

As one can see from Table 1 the largest volume of reductions is produced by AM0009 projects, while project executed under other AMs still producing healthy levels of reductions.

The key barriers to having more projects under these 5 methodologies include as follows:

- Very restrictive nature of the methodologies' scope, which dramatically reduce the number of potential prospects;
- Lengthy and complicated process of obtaining validation and then registration
- High costs of project preparation and monitoring
- Lack of trained local consultants and staff in oil and gas companies.

Some of these barriers could be lowered if a project development and training financing is available.

2.3.2 CDM in Azerbaijan

2.3.2.1 Overview of CDM Projects in Azerbaijan

Azerbaijan Republic ratified both the UN Convention on Climate Change in January,

1995 and Kyoto Protocol – in June, 2000. As a country with developing economy, Azerbaijan Republic has no quantitative commitments on reduction of greenhouse gases emissions into environment. However, since the ratification date Azerbaijan Republic takes active part to develop measures towards greenhouse gases emissions reduction.

Like in many developing countries at the early stage of implementation of Kyoto protocol Azerbaijan has faced numerous challenges. These challenges were mostly linked with lack of institutional resources and capacity to support CDM projects. To tackle these challenges Azerbaijan government has been involved in several technical assistance programs provided by international organizations such as UNDP, TACIS and CIDA. These organizations have implemented series of technical assistance programs in Azerbaijan since 2003 by engaging government and project proponents. As a result of strong commitment of government of Azerbaijan and targeted technical assistance by international organizations National Designated Organization was established in April 2005 and first CDM projects commenced development in 2006.

There are 14 CDM projects in pipeline in Azerbaijan as of November, 2009. These projects cover different sectors of economy such as oil and gas production, methane capture, agriculture and electricity generation. Most advanced CDM project form the list below is at validation stage. The up-to-date overview of CDM projects under development in Azerbaijan Republic provided in Table 2

Table 2: Projects in Pipeline

Azerbaijan	Location	Category	Status level
Hydropower station	Ordubad, Fuzuli Gilanchay	Renewable energy	PIN
Rehabilitation of Azerbaijan ThPP	Mingechaur	Energy efficiency	Validation
Construction of Sumgayit PP	Sumgayit	Energy efficiency	Validation
Associated Gas Capture from Gushkhana Oil Field	Caspian Sea Gushkhana area	Methane capture	PIN
100 MW Find Farm in Shurabad	Khizi district	Renewable energy	PIN
Capture of gases from Grifons at the bottom of Caspian Sea	Offshore	Methane capture	PIN
Construction of Ordubad HPP	Nakhchivan Autonomous Republic	Renewable energy	PDD
Natural gas leakage reduction in compressor stations and distribution gas pipeline	Garadagh district	Methane capture	PIN
Power transmission	Territory of Azerbaijan	Energy efficiency	PDD
Afforestration in some areas of Azerbaijan	Zagatala, Masalli	Carbon sinks	PIN
Recovery of the vented gas at the Guneshli Oild Field	Offshore oil field in Caspian sea	Methane capture	Validation

Imishli Sugar Plant	Imishli	Energy Efficiency	PDD
Ali Bayramli ThPP rehabilitation	Ali Bayramli	Energy efficiency	PIN
Construction of the unit #2 at the Shimal CCGT	Absheron	Energy efficiency	PIN

2.3.2.2 Projects in Oil and Gas Flaring/Venting Reduction

The only CDM project focused on venting/flaring prevention in Azerbaijan is the "Recovery and transport of the vented gas at the Guneshli oil and gas field in Azerbaijan". Over last 20 years the Gunashli oil field has vented to the atmosphere about 7 billion m3 of gas. The purpose of the proposed CDM project is to recover presently vented low-pressure gas at the Guneshli oil field which operated by the national oil company SOCAR. The high-pressure gas at the Guneshli oil field that does not require additional compression is transported on-shore but the low-pressure gas is vented into the atmosphere. The vented gas originates from separators installed on the off-shore platforms where oil and liquids are separated from gas. Gas separated from oil is vented to the atmosphere at atmospheric pressure. The proposed CDM envisages the following activities: a) construction of a collection pipeline system to connect ten off-shore stationary platforms at the Guneshli oil filed with a 325 mm underwater pipelines to the platform (#4); b) construction of the new 13,4 MW (with 2 turbines) compressor station at platform #4; c) construction of 508 mm pipeline to transport pressurized gas to the existing natural gas line at the Neft Dashlari oil field.

The ex-ante calculations of the emission reductions from the Guneshli project are based on the well-level data from 2004 to 2007. According to the sampling results, the annual average volume of the low pressure gas from all the Guneshli wells equals to 290 million m3/year. It is expected that there would be continuous decrease in the associated gas recovered from the oil field; however it would be compensated by increase in the gas-lift gas being used (and subsequently vented) to increase the production as the pressure in the Guneshli field decreases. Thus, the expected volume of gas to be vented from the Guneshli field is taken as constant at 290million m3/year throughout the CDM crediting period. The utilization of this gas will correspondingly result in about 450 000 tCO2e per year in emission reductions.

2.3.2.3 National CDM Procedure in Azerbaijan

As a country with developing economy, Azerbaijan Republic has no quantitative commitments on reduction of greenhouse gases emissions into environment. However, since above mentioned directory documents ratification date Azerbaijan Republic takes active part to develop measures towards greenhouse gases emissions reduction. All duties relevant to the CDM Projects are entrusted to the Azerbaijan Republic Ministry of Ecology and Natural Resources by the Azerbaijan Republic President's Direction №727 dated 1 April, 2005.

From this date on the MENR became Designated National Authority (DNA) for Azerbaijan. The institutional structure of DNA is the following: DNA is the Ministry of Ecology and Natural Resources; secretariat and 5 working groups for technical input (energy efficiency and fuel switch, landfill, alternative energy, methane capture, afforestation and carbon sinks). DNA should enable the environment for flexible, effective and successful implementation of the CDM projects: selection of CDM priority sectors, establishment of SD criteria, monitoring of EIA for each CDM project, providing fro national guidelines to present

PIN and PDD issuance of approval letters, facilitations of the process of signing the MoU with different bilateral and multilateral CDM project.

MENR as a central state body is providing state policy in environment production, organization of the natural resources using and carrying out of the hydro-meteorological works and so on (www.eco.gov.az). The main responsibilities of the ministry are shown below:

- Studying of the natural resources, using them, providing of the restoration and protection activities and controlling of the environmental safety and also providing of the state policy in the biological diversity sphere;
- Rational using of the inner water biological resources and also the water resources of Caspian Sea, providing in this sector the state policy;
- Studying and providing of the state policy in earth research and protection and rational using of it;
- Preparing and providing of state programs regarding the forestry using, protection and reforestation activities in all republic territory;
- Composing and implementing of the national action programs on environment and geology and mineral products;
- Preparing and implementing in its authority the state programs for protection and using of the water resources;
- State managing of the environmental protection and natural resources using sphere in Azerbaijan Republic to create the healthy situation for people;
- Organize the hydrometeorology services, providing the hydrometeorology observations? Prepare the forecast and distribution it between the stakeholders;
- Providing the state control on flora and fauna and also in environment air protection;
- Implement the international convention on environment that Azerbaijan Republic approved and in the framework of its obligation to cooperate the different bodies involved in these activities;
- Providing other activities that imposed to the MENR by legislation.

2.4 Potential new CDM methodologies

While most project situations in Azerbaijan could be addressed by existing approved methodologies, there are a few exceptions. This section explains which new methodological submissions may need to be made by CDM project proponents who want to develop new project opportunities in the country.

2.4.1 Emissions from on-shore oil wells

The on-shore oil wells in Azerbaijan leak substantial quantity of associated gas (AG). These emissions could be prevented by either collecting the gas by vacuum lines from active or closed wells or sealing the closed wells. The extrapolation of the measured emissions at the

Balakhany field leads to an estimate of about 142 million m3 of gas leaked per year from all active wells at nine on-shore production sites in Azerbaijan, which is equivalent to over 2 million tCO2e per year. Still more is emitted from closed wells. This volume of potentially abatable emissions is quite substantial and merits some efforts in developing corresponding methodological approaches.

It is rather doubtful that any of the existing methodologies will be directly applicable to this project situation. While AM0009v4 is formally applicable, its direct application will lead to more than a seven-fold reduction in the volume of CERs that could be obtained from the project, since all the methane emitted from wells must be converted to CO2 (despite the fact that flaring is not a common option at on-shore oil production sites).

On another hand, the AM0023 which counts methane as methane when it comes to the baseline is also not directly applicable since it applies only to gas distribution and gas compressor stations.

Hence, the new methodology or a revision to an existing methodology needs to be developed. From the preliminary analysis we conclude that the most promising way is a revision to AM0023. The following revision directions could be suggested:

#	**Existing Applicability Condition**	**Proposed Revision**
1	Where natural gas pipeline operators have no current systems in place to systematically identify and repair leaks	Where natural gas and oil production, transmission and distribution operators have no current systems in place to systematically identify and repair leaks
2	Where leaks can be identified and accurately measured	No change
3	Where a monitoring system can be put in place to ensure leaks repaired remain repaired	No change

This revision should be relatively easy to introduce and its acceptance by CDM EB is likely.

However, a much more difficult task is to develop a system of on-going monitoring and repair of the actual leaks at the existing facilities. The difference with natural gas operations is that fixing the leak in the pipeline automatically qualifies for an emission reduction, whereby fixing a leak in the oil well head may be counterweighted by a new leak in a nearby wellhead or crack in the surface. Thus, it has to be proven that sealing properly all active (or closed) wells do indeed lead to permanent emission reductions.

2.4.2 Emissions from gas processing plant

A largest gas processing plant in Azerbaijan located at Garadahg is reported to loose substantial quantity of gas via flaring. The currently flared gas could be collected and used for heat and power generation on-site. This measure could potentially form the basis for a solid CDM project. Also, as in the previous case only a deviation from the existing approved methodology AM0055 is necessary.

#	**Existing Applicability Condition**	**Proposed Revision**
1	In absence of the project activity, based on historical data, waste gases from the refining facility, used by the project activity, were flared (not vented) for the last 3 years, prior to the start of the project, or as long as the processing facility has been in operation.	In absence of the project activity, based on historical data, waste gases from the refining or gas processing facility, used by the project activity, were flared (not vented) for the last 3 years, prior to the start of the project, or as long as the processing facility has been in operation
2	The recovery device is placed just before the flare header(with no possibility of diversions of the recovered gas flow) and after all the waste gas generation devices	No change
3	Recovered waste gases are used in the same refinery facility.	Recovered waste gases are used in the same refinery or gas processing facility
4	The project activity does not lead to an increase the production capacity of the refinery facility	The project activity does not lead to an increase the production capacity of the refinery or gas processing facility
5	Local regulations neither constrain the refinery facility from using the fossil fuels currently used in the existing process nor require flaring of the recovered gas.	Local regulations neither constrain the refinery or gas processing facility from using the fossil fuels currently used in the existing process nor require flaring of the recovered gas
6	Waste gas volume and composition are measurable	No change
7	There should not be any addition of fuel gas or refinery gas in the waste gas pipeline between the point of recovery and the point where it is mixed in fuel gas system or used directly in element process	No change

2.5 Technical potential for flaring and venting reduction in Azerbaijan

2.5.1 Main flaring and venting locations

The main sources of associated gas venting and flaring in Azerbaijan could be subdivided into three major groups: (1) venting/flaring at off-shore platforms; (2) venting at on-shore oil wells; (3) venting and flaring at gas and oil processing facilities.

The Table 2 below summarizes the volumes of flaring at different off-shore production sites in Azerbaijan. The volume of annually flared gas at these sites is quite substantial and is similar to the average annual amount vented at the Gunashli shallow platform (290 mln m3/year), which is subject to a current CDM project (see above). About half of this amount is vented at the adjacent Neft Dashlary oil field. A similar volume of annual venting losses was estimated for all the on-shore oil fields in Azerbaijan (based on the instrumental measurements)–140mln.m3/year.

Table 3: Volumes of flared AG at off-shore oil production sites (thousand cubic meters)

Information on gas flaring							
Years	«Chirag-1» Platform	«Central Azeri» Platform	«West Azeri» Platform	«East Azeri» Platform	«Deep-water Gunashli» Platform	Sangachalsky Terminal	Total
2000	396 249.884	0	0	0	0	0	396 249.884
2001	269 754.213	0	0	0	0	0	269 754.213
2002	251 123.222	0	0	0	0	0	251 123.222
2003	274 151.793	0	0	0	0	0	274 151.793
2004	296 354.951	0	0	0	0	0	296 354.951
2005	306 524.211	101 819.794	0	0	0	0	408 344.005
2006	175 669.126	99 601.000	63 994.200	13 379.400	0	44 592.000	397 235.726
2007	53 156.954	56 016.961	19 002.199	54 000.658	0	68 647.901	250 824.673
2008	56 060.873	63 438.879	21 206.832	63 585.969	121 761.624	55 379.468	381 433.645

Based on statistical data, field measurements and expert analysis the top-nine list of faring/venting sites in Azerbaijan is as follows:

1. Azeri-Chirag-Gunashli (deep) off-shore oil production.
2. Gunashli (shallow) offshore oil porduction
3. Neft Dashlary off-shore oil production
4. Sangachal oil terminal
5. Garadag gas processing plant
6. Oil refinery named after Geidar Aliev
7. “Azerneftiag” oil refinery
8. On and off-shore oil production at “AbsheronNeft”
9. On-shore oil production at “BalakhanyNeft”

2.5.2 Main technical approaches to flaring/venting prevention

Similar to natural gas and oil associated petroleum gas (APG) is one of the nonrenewable natural resources of significant value. Dissolved gas becomes a standalone product in the beginning of the oil preparation stages requiring expenditures connected with its preparation, transportation and conversion.

APG at the initial stages of oil separation has sufficient pressure to be transported at 40-50 km distance, while APG at the terminal separation stages is under the nearly atmospheric pressure and requires significant expenditures connected with its preparation and transportation. As a result hydrocarbons of great value are frequently flared and products of their combustion are released into the atmosphere. Not only methane as a key APG component is flared but also a wider hydrocarbon group such as ethane, propane, butane, pentane, hexane, etc..

As other oil producing countries, Azerbaijan has a challenge associated with bulk minimization of flaring and venting of APG and using it as a valuable resource. There are 231 on-shore and off-shore perspective structures under exploration in Azerbaijan today. Among them: 38% are located on-shore and 62% - off-shore. Generally, 5-10% of oil and gas in Azerbaijan in produced from on-shore fields and 90-95% -- from off-shore fields.

Associated petroleum gas losses were historically connected with infrastructure unpreparedness for APG gathering, preparation, transportation and processing. Therefore, APG was just flared and in the case of flare unit absence - vented. Rational use of associated petroleum gas in the process of oil production gathers a specific status today against the background of understanding by the world public of the significant environmental damage caused by flaring and venting. Associated petroleum gas utilization is one of the key priorities of the national economic development in Azerbaijan as well as in any other oil-producing country. At the same time the venting and flaring gas problem have a significant ecological aspect. The scope of the environmental damage can be seen from the example of the oil and gas producing unit “28 of May”, operating the Gunashli (shallow) off-shore and Chilov fields. At this off-shore field production, as consequence of the natural reservoir pressure decline, well production rate drops and oil wells with free-flow production method of operation are converted to the gas lift ones. The Gunashli development project utilizes the gas lift method, since another lift well operation methods such as, for example, the down-hole sucker-rod pump are not applicable to deep wells (more than 3000 m).

Gas usable in the gas lift well operations as working substance is subsequently vented along with the associated petroleum gas.

As mentioned above, rational associated petroleum gas use is not just an ecological problem but is both the ecological and economic one. Taking into account the purchasing natural gas price for Russia (1000 Cm of gas - $ 350) and multiplying it by 3,5-4 billion m3 of gas lost per year, the Azerbaijan Republic loses a huge sum of money – about $1,4 billion annually (this amount is even bigger if petrochemicals produced frm APG are taken into account).

Associated petroleum gas utilization problem seems to be a complicated one and consists of such aspects as ecological, technological, and economic, representing a global task for decades. The abovementioned problem is solved partly within major fields, but obviously, urgent assistance is required for small hard-to-reach fields.

In order to eliminate adverse ecological impact and turn-in high-value hydrocarbons the key issue to consider should be promotion of state-of-art technology at oil and gas fields,

including utilization of all the extracted hydrocarbons (oil, gas, condensate, dissolved gas) during early field development. The step-by-step implementation of the abovementioned plan requires large capital investments.

In due time the following engineering solutions in the field of gathering and transportation of petroleum gas and reducing the hydrocarbons losses were conducted at some fields in Azerbaijan:

- Gathering and utilization of gas produced at the end stages of separation process by vacuum compressors;
- Light oil fraction capture and storage in oil tank;
- Gas drying for transportation;
- Sour gas cleaning and processing;
- Multiphase transportation of liquid-gas mixture by oil pipe lines up to oil and gas processing plants;
- Constructing low pressure gathering pipelines;
- Associated petroleum gas processing at the field with getting marketable products;
- Introduction of deep degasification technologies and stabilization of gas condensates.

In contrast to centralized energy supply today the technology market provides oil companies with wide range of oil and gas power generation systems, in particular, new gas piston power plants and gas turbine electric power stations, and energy generators on fuel elements. Implementation of such systems, providing oil fields with thermal and electrical energy solves a lot of problems, including the problem associated petroleum gas utilization.

As international experience shows, there are three main practical measures on APG utilization at small distant oil fields (despite of plenty of potential associated petroleum gas utilization technologies):

1. Gathering and processing of vented and flared gas at the gas processing plants with extraction of broad fraction of light hydrocarbons and production of dry gas for delivery to main gas transmission lines. One of the perspective ways of such processing is production of liquid hydrocarbons (gas-to-liquids -- GTL);
2. Implementation of small **gas turbo-generators** for producing electrical power and it's following sales to the electrical grid. Associated gas an be used for power generation after being properly collected and processed.

   Figure 1 below shows the gas powered electrical generator, wile **Figure 2** depicts gas-turbine power plant OPRA DTG -"**G**" that can be fueled by APG. Electrical power plants OPRA DTG with "**L**" index operate on diesel oil. There are also bi-fuel generators DTG-1, 8/2**GL** (gas/diesel). OPRA power generators may function on associated petroleum gas. (see: ***http/www.manbw.ru/anality/scopra.html***)

Figure 1

Figure 2

3. **Gas reinjection** in to the oil well to enhance oil recovery. This method represents repeated gas injection into oil producing layers (gas caps, water-bearing horizons) in order to support reservoir pressure, increase oil recovery, maintain gas resources and prevent flaring and venting of APG. Gas reinjection is used as a secondary mechanism requiring gas preparation and compression. It requires additional expenses but at the same time extended the oil field operating time. The re-injections can be done multiple times for the same volume of gas during the well exploitation.

Combination of all abovementioned measures allows utilize up to 95-98% associated petroleum gas resources. The last mentioned utilization measure is used when opportunities of the first and the second measure are limited, for example, at the beginning of oil field exploitation, on small fields or off-shore fields.

A generic nation-wide associated gas utilization plan can potentially include gas processing plant construction together with well-developed network of APG gathering lines. Implementation of traditional utilization plans requires significant investment costs and time and according to world experience usually falls behind the oil fields development. Implementation of such complex plans may be cost effective only at large scale when the volume of APG is in billions m3 of gas, while it makes little economic sense at medium- and small-scale.

Another disadvantage of abovementioned plan is its failure to utilize associated gas of end separation stages due to heavy hydrocarbon content (for technical and transport reasons).

Small and medium oil fields, distant fields and old fields produce most of flared ad vented gas. Gas gathering from such fields based on complex utilization plans (feasible for new large scale operations) is very capital-intensive and not very economically attractive.

Construction of petroleum gas liquefaction generators, motor fuel preparation facilities, and methanol producing plants at small remote fields does not worth detailed evaluation due to its low economic attractiveness, although a modular energy generator allowing producing

methanol or motor fuel parallel with thermal and electric power production may still be feasible.

As for electric power production, it is one of the most effective types of associated petroleum gas utilization, which allows not only to solve gas utilization problem, but also recover project money, making a profit on power purchase cost reduction.

Taking into account all abovementioned concerns surrounding international experience in selection of the most appropriate technical alternatives to flaring and venting of APG and starting from on-the-ground situation with low pressure gas utilization at oil and gas facilities in Azerbaijan, it is possible to make a few suggestions about potential choices. However, it should be noted that each filed is unique and detailed technical planning requires comprehensive technical and engineering audit of each field with further development and implementation of cost-effective utilization measures.

In case of on-shore fields, there is an objective necessity of full (for fields with long operational life) or partial (for fields with relatively short operational life) re-construction of existing gas gathering and transportation system. In particular, partial reconstruction of associated low-pressure gas vacuum system on “BalakhanyNeft” fields is possible. Taking into account that operational life of existing vacuum system is more than 50 years (some parts of it are dated back to 1937) the most preferable solution is complete reconstruction of existing vacuum system. This reconstruction can be supplemented by liquidating of marginal and low-producing wells.

Partial reconstruction of an existing vacuum system is possible on “BibiabatNeft” Oil/Gas Production Division fields. It should be mentioned, that major efforts concerning new oil/gas equipment installation (reservoirs, separators) are taking place at both “BibiabatNeft” and “BalakhanyNeft” oil/gas production fields. Also, connection to vacuum system is performed for wells wit relatively high rates on gas losses. In addition, at both fields connection major efforts are planned for encapsulation and sealing of existing gas gathering systems.

A similar situation takes place and at other on-shore fields. Operational life of fields managed by oil/gas Production Divisions named after A. Amirov and H. Z. Tagiyev as well as by “SiyazanNeft” exceeds 80 years. Existing equipment is outdated and vacuum system does not cover all wells, from which gas is vented to the atmosphere.

Enlarged oil-extracting enterprise “Muradkhanly” holds a most unique position among other on-shore fields. At this enterprise oil is produced by free-flow production method. According to this method, gas together with oil is channeled into the collector. As a result, there are no gas losses from the wells and gas is vented only from oil tanks and reservoirs.

As for off-shore fields, the most important question to decide with respect to flaring/venting prevention is realization of complicated set of measures on sealing and tightening of sub-surface equipment and transportation system. Besides, at present time design works on making up compressor generators and multiphase pumps to “Neft Dashlary” Oil/Gas Production Division and Oil/gas Production Division named after “28th May” grounds are implemented. Oil production at oil/gas Production Division “Gumadasy” fields is conducted

both by gas-lift and free-flow production method. There are no gas losses from wells to atmosphere as it takes place on other off-shore fields, using gas-lift oil producing method. So, improving the gas-lift oil producing technologies, as one of the important alternatives to venting/flaring gas, gains significant importance at off-shore fields.

To sum it up, it should be mentioned that most of associated gas utilization activities are de facto both housekeeping and environmental protection activities. Under present-day conditions environmental protection activity is one of the most significant and higher-priority state functions.

3 Opportunities for financing CDM projects in the area of associated gas (AG) flaring/venting prevention

3.1 Conventional financing

The regular financing of APG flaring/venting prevention measures is planned and accomplished according to the same procedure as with other investment projects. The sources of such conventional financing include own resources of the oil company; loans; equity and project financing. The typical analysis of different options for AG projects at sample oil filed is described below.

Option 1: No project is implemented. APG is flared a in the base case;

Option 2: Construction of generator to liquefy APG;

Option 3: Construction power generation plant based on APG.

Table 4: Economic efficiency indicators for oil company

Item	Option 1	Option 2	Option 3
Funds saved for 5 years period (th/rub)	-1 923 750	35 000	**1 230 000**
Project NPV for oil company for the 5 years period (th/rub)	-1 121 514	12 000	**715 000**
Project IRR for oil company	no	3 %	**16 %**
Payback period for oil company	no	50 years	**8 years**

Project economic efficiency indicators are basic elements for projects comparison. Key economic efficiency investment indicators are: NPV – net present value. IRR – internal rate of return or %DPB –discunted payback period

According to Table 4 it is obvious that refusal to implement the project (Option 1) may lead to significant losses for a license holder connected with gas venting and fiscal sanctions of control authorities, because state requirements and the license agreement conditions are not implemented well. Own potential investments (Option 2) of license holder into the gas liquefaction (cryogenic methane) plant is very costly, which will make the project economically unattractive, even in the long run. At the same time Option3 will allow to

generate substantial additional cash-flow for the oil company by replacing the grid electricity with electricity generated by APG-fueled plant.

One of the most attractive approaches to increase commercial attractiveness of projects to oil companies is to sell APG to an external investor right at the site. In this case the company itself does not face any additional costs associated with developing infrastructure needed for AG utilization.

3.2 Carbon financing

The Kyoto Protocol provides developing countries additional means for financing AG flaring/venting reduction projects via carbon markets. These markets are based on the situation when Governments and companies in Annex I countries purchase project-based greenhouse gas emission reductions in developing countries or in other Annex I countries mostly to meet their obligations under the Kyoto Protocol or to trade them on the market for a potential profit. Emission reductions are defined as a measurable reduction of release of greenhouse gases into the atmosphere from a specified activity or over a specified area, and a specified period of time. Emission reductions are typically measured in tons of carbon dioxide equivalent (tCO2e).

The money that flows to countries hosting GHG emission reduction activiies under CDM transactions is widely known as “carbon finance”. Carbon finance is basically a payment to a project entity (this can be any legal entity, public or private, NGO, etc) for the emission reductions generated from that project, once the project is operational and tipically at yearly basis, like a commercial transaction. The selling of emission reductions - or carbon finance - has been shown to increase the financial viability of projects, by adding an additional revenue stream in hard currency, which reduces the risks of commercial lending or grant finance. The carbon finance can also help overcoming barriers for project development and implementation, e.g. improving access to financial resources, enabling transfer of technologies and know-how. Thus, carbon finance provides a means of leveraging new private and public investment into projects in developing countries and economies in transition that reduce greenhouse gas emissions, thereby mitigating climate change while contributing to sustainable development (http://web.worldbank.org/WBSITE/EXTERNAL/TOPICS/ENVIRONMENT/EXTCARBONFINANCE/).

The overall level of finance available from the international carbon markets is summarized in a table below.

Table 5: Carbon Market at a Glance, Volumes & Values in 2007-08

	2007		2008	
	Volume (MtCO2e)	Value (MUS$)	Volume (MtCO2e)	Value (MUS$)
Project-based Transaction				
Primary CDM	**552**	**7,433**	**389**	**6,519**

JI	**41**	**499**	**20**	**294**
Voluntary market	**43**	**263**	**54**	**397**
Sub total	**636**	**8,195**	**463**	**7,210**
Secondary CDM				
Sub total	**240**	**5,451**	**1,072**	**26,277**
Allowances Markets				
EU ETS	**2,060**	**49,065**	**3,093**	**91,910**
New South Wales	**25**	**224**	**31**	**183**
Chicago Climate Exchange	**23**	**72**	**69**	**309**
RGGI	**na**	**na**	**65**	**246**
AAUs	**na**	**na**	**18**	**211**
Sub total	**12,108**	**49,361**	**3,276**	**92,859**
TOTAL	**2,984**	**63,007**	**4,811**	**126,345**

For the third consecutive year, European buyers continued to dominate the CDM and JI markets for compliance (Figure 3), with a combined market share of over 80% (similar to 2007). Private sector companies have been the most active buyers, with slightly less than 90% of volumes contracted, including JI purchases. Even now, in the midst of the economic downturn, European utilities were, and still are, reported as active, if price-sensitive buyers. They are purchasing primary CERs with an eye to their Phase III future compliance needs as well as on making small profits from trading (World Bank: State and Trends of the Carbon Market 2009).

3.2.1 Necessary Documentation for realization of CDM projects and carbon financing

There are three key documents for realization of the CDM projects and receiving associated carbon financing. These are project idea note (PIN), PDD and Emission Reduction Purchase Agreement (ERPA).

The key objective of PIN is to outline general aspects of the project and preliminary quantify its costs and benefits, without developing detailed baseline studies and monitoring plans. In particular the project idea can encompass existing GHG fluxes at a project site and expected changes in GHG fluxes from project activities. PIN is reviewed by DNA and supported by letter of endorsement subject of meeting country's sustainability aspirations. PIN is usually developed and submitted to DNA by project owners.

PIN is a concept widely used by international GHG project donors. For example World Bank uses PINs as the first and necessary step to the project development.

Basically a PIN consists of approximately of 5 pages providing information on:

- Type, size of the project and its location
- Objective of the project
- Anticipated total amount of Greenhouse Gas (GHG) reduction compared to the

"business-as-usual" scenario (which will be elaborated in the baseline later on at Project Design Document [PDD] level)

- Proposed crediting life time
- Financial structuring (indicating which parties are expected to provide the project's financing)
- Project's other socio-economic or environmental effects/benefits
- Project description and proposed activities (including a technical description of the project)
- Technology to be employed
- Information about project developers and sponsors
- Location of the project
- Expected schedule
- Baseline scenario
- Specific global & local environmental and socio-economic benefits

While every effort should be made to provide as complete and extensive information as possible, it is recognized that full information on every item listed in the template will not be available at the early stage of project development.

This report includes two sample PINs drawn from the practice and applied by World Bank and MCCF (See attachment 1 & 2). Comparative analysis revealed that both sample of PINs are similar with slight differences. For instance PIN presented by MCCF is more detailed specially on issues related with environmental and social impacts of project. It also asks to specify IRR forecast for project which is not required in the template of World Bank. These differences by no means undervalues one PIN over other and project owner is free to choose what kind of PIN template to use. Rule of thumb is that more information presented in PIN serves for better evaluation of project by potential developer.

In order to implement a CDM project, the project participants must also prepare a PDD including a description of the baseline and monitoring plan to be used, an analysis of environmental impacts, comments received from local stakeholders and a description of the additional environmental benefits that the project will generate. *This is a key document broadly describing the projects specification, the methodology employed and volume of estimated reduction.* A national authority issues the written *national approval* of CDM projects based on information provided in PDD. The national approval process of CDM projects is not internationally regulated. It is assumed that this process would include a project review, which ensures that a proposed CDM activity complies with national socio-economic and environmental priorities. The national approval and/or registration process may take place before the project validation, based on either project idea note or the completed PDD.

The CDM executive board has developed and adopted a standardized document format (i.e. PDD), which should be used for submitting CDM proposals to the board. PDD includes the following provisions:

- General description of project activity

- Baseline methodology
- Duration of the project activity / Crediting period
- Monitoring methodology and plan
- Calculations of GHG emissions by sources
- Environmental impacts
- Stakeholders comments

The annexes to the project document should be as follows:

- Annex 1: Information on participants in the project activity
- Annex 2: Information regarding public funding
- Annex 3: Baseline methodology
- Annex 4: Monitoring methodology
- Annex 5: Baseline data

3.2.2 Emission Reduction Purchase Agreement (ERPA)

3.2.2.1 Definition of ERPA

ERPA is long term legal binding document defining all responsibilities of buyer and seller related with delivery and payment of CERs as a product of CDM project. As such, ERPA has a significant role in regulating the relation between buyer and seller throughout the project execution. Due to uncertainties in CDM project cycle a great deal of risk persists on delivery of CERs. Hence, ERPA is also envisaged as a tool by which financial risks are managed between buyer and seller. The International Emission Trading Association (IETA[1]) has introduced first draft of ERPA in June, 2004 and has developed it in consecutive years. There ERPA templates used by international financial institutions such as World Bank and European Bank for Reconstruction and Development (EBRD).

IETA has developed template which was widely used by project participants in different markets. Based on the template developers has customized ERPAs to make it specific to project requirements. Latest version of the IETA's ERPA dates to August 2006.

This report refers to comparably newer template of ERPA drafted by by an international group of lawyers and CDM experts and sponsored by the INTER-AMERICAN INVESTMENT CORPORATION (IIC), a member of the Group of the Inter-American Development Bank. This template was introduced for public discussion in April, 2007 and has broader approach in addressing risks.

[1] The International Emissions Trading Association (IETA) is a non profit organization created in June 1999 to establish a functional international framework for trading greenhouse gas emissions reductions. Its 134 international members include leading multinational companies from across the carbon trading cycle: emitters, solution providers, brokers, insurers, verifiers and law firms.

In practical terms project participants tend to customize ERPAs. The rational for customization is the need for specific risk management and laws by which participants are governed. It is noteworthy to mention that law of the country presented by the buyer has prevailing influence in the content of ERPA. However, major provisions of ERPA remain the same in both cases. The customized sample of the ERPA is discussed in Section 5 with attachment provided in Annex 2.

Object of ERPA is CERs i.e. each metric ton of CO2 equivalent reduced by a CDM project and approved and issued by the CDM Executive Board after verification and certification. It is the product which is commercialized via the ERPAs.

3.2.2.2 Role of ERPA in CDM projects

Project development cycle and procedures of CDM allows signing of ERPA any time after Project Idea Note (PIN) is developed and verified. But, it is a common practice that ERPA is signed after the Project Design Document (PDD) is drafted and further developed. The rationale for this approach lies in gaining more assurance of estimated emission reductions and delivery terms. At early stage of project development there is a great degree of uncertainty about volume of CERs and delivery schedule. However, it is often a good case for buyers to bargain on good deal by arguing on risks of project. The risks of project reduce as it develops into next stage. Hence, there is positive relation between price and project development. The further project is developed more risk is reduced. Consequently negotiated price of CERs price rises as risk reduces. This relation is described below:

- PIN stage
- PDD stage
- Registered project
- Issuance from project

Key reference documentation in developing ERPA in CDM projects

Buyer and Seller make frequent reference to project documentation and legal regulations of host country in developing ERPAs for CDM projects. Key project documents referred to are PIN, PDD, Validation Report (subject to availability upon conclusion of ERPA) and approved procedures and regulations of UNFCCC (UNFCCC, 2009). PIN and especially PDD provides buyer with estimated volume and schedule of CERs to be delivered by the Seller. PDD also outlines Monitoring Plan which linked to the ERPA where Buyer refers to it as source of evidence for delivery of CERs. Monitoring plan is developed according to the project methodology approved by Executive Board of UNFCCC. Any reference documentation referred to in the ERPA should be attached to it.

Major provisions of ERPA

Standard ERPAs stipulate following relations between buyer and seller:

a. Definition and Terms
b. Obligation to deliver credits (including interval)-it is commitment by the seller to produce and deliver CERs. Failure do deliver may lead to imposition of fines and legal actions against the seller by buyer. The terms and conditions of such actions are stipulated in the ERPA.
c. Amount of credits to be delivered

Two methods of describing how many CERs are to be bought and sold are included in the ERPA – a fixed amount and a percentage of generated CERs. Fixed amount contracts are more common as they clearly establish the sale and purchase liability for the buyer and seller, and the amount of revenue that can be expected by the seller.

This volume is based on and represents the total volume defined in PDD. Sellers need to be precautions in committing this volume as the failure to deliver the agreed volume will result in imposition of fines on them by buyers. It is often quite risky for the buyer if fixed amount of CERs is committed to deliver in short time. To avoid such risk seller may agree on longer term for delivery of most conservative calculations for CERs volume.

d. Schedule of delivery

Where a contract only covers CERs generated during the first commitment period of the Kyoto Protocol (2008-2012) the period in which CERs are to be generated ends on the 31 December 2012. If CERs generated after 31 December 2012 are also being bought and sold, a later date applies

e. Payment And Price (Unit Price)

This provision may include four alternative methods of calculating the Unit Price paid per CER; *fixed price; simple indexed price; a combination of an indexed price and a fixed price; and an indexed price with a floor and ceiling.*

Fixed Price - The simplest approach is a fixed unit price per CER. This fixed price will remain in effect for the term of the agreement. This approach provides certainty to both parties. Note, however, that it does not explicitly take inflation or market fluctuations into account. These can be taken into account when the parties negotiate the fixed price. Inflation can also be taken into account with a fixed price contract by stipulating that the Unit Price will automatically increase by X% each year.

Indexed Price - An indexed price will refer to a spot market price to calculate the unit price. The spot market price can either refer to CERs or, more likely, to other emission reduction units, such as the spot allowance price in the EU. As a result, the unit price will fluctuate and change with each annual payment. Such calculation method entails opportunity and risk (for ex. crash of market price) for both the seller and buyer, depending on how the reference spot market price changes over the term of the agreement. Using a simple indexed price means that neither the seller nor its banks will be able to calculate the carbon revenue, and thus the value of the agreement.

Revenues based on indexed price agreements are shared according to the agreed proportion between buyer and seller. Depending on specifics of project proportion of shares ranges in practice between 60-90 % to 40-10 % in favour of seller. It varies depending largely on risks and development costs of the project. In CDM projects in Azerbaijan under revenue sharing agreement buyers receive from 15% up to 35% of projected revenues.

Combination indexed and fixed price - Combining a mixture of a fixed unit price per CER and an indexed price guarantees a minimum price and reduces the impact that spot price fluctuations have on the unit price. A combination of an indexed price and a fixed price can also incorporate a ceiling and a floor on the unit price as described below.

Indexed price with a floor and ceiling - Including a floor (i.e. minimum) and a ceiling (i.e. maximum) on the unit price protects both the seller and the buyer from larger movements in the spot price and should assist in longer term planning.

f. Options: Put and Call Options

CER sale and purchase agreements can include both call and/or put options. A call option over a CER is a right but not an obligation to buy the CER (i.e. the buyer has a choice whether or not they buy, and the seller must sell if the buyer wants to buy). A put option over a CER is a right but not an obligation to sell (i.e. the seller can choose whether or not to sell, and the buyer will have to buy if the seller chooses to sell). Sample option language is included below. The Parties should consider factors such as: when the option is exercised; whether it can only be exercised once or over a number of years; whether it can be exercised for CERs generated after 2012; the price to be paid for the CERs bought and sold under the option; and any premium paid for the option.

It is important to note that the exercise price[2] for post 2012 CERs should be given careful consideration. At the time of writing, the post-2012 market for CERs is quite limited due to a number of factors including: uncertainty over whether or not the CDM will continue after 2012; uncertainty over what the demand for CERs may be after 2012 even if the CDM is operational; and uncertainty over treatment and fungibility of CERs generated after 2012. However, current indications are that some sort of market will exist after 2012 which should be factored into any price agreed for post-2012 CERs.

g. Consequences of non-delivery and other events of default (e.g. delivery path failure)
h. Distribution of (regulatory) costs

The provision on distribution of project development costs in ERPA explicitly defined through negotiations between buyer and seller. Development cost of project as rule consists of following items with average estimates for each given in brackets:

- PDD development (€20,000)
- Validation (€40,000)

[2] The "exercise price", or "strike price" is the price the parties agree to buy or sell under an option.

- Registration fee[3]
- Monitoring and Verification (€15,000)

The values for cost items may vary depending on the size and complexity of project. PDD development services may be provided by third [arty contractors. In this case cost of may be higher. It is also practical to develop PDD by engaging in-house resources to save in cost. Validation services are provided by Designated Operating Entities (DOE) which are exclusively authorised by UNFCCC to conduct validation and verification services. The cost for validation services rose in last three years from average of €25,000 to €40,000. Such sharp rise is explained by rising demand for services in limited supply (Number of DOEs is limited to 28 organizations).

Developers (buyers) try minimizing the upfront payments for project development so that project Net Present Value (NPV) is maximized and would encourage buyers to take responsibility for these expenses. When upfront costs covered by Sellers they would give only very small portion of CERs. Hence, there is extensive scale of trade-off over upfront costs of project development.

i. Representations and Warranties
j. Force Majeure
k. Termination rights –Sets out rules and procedure for termination of agreement.
l. Governing law and dispute resolution

Parties agree on governing law according to all disputes will be resolved between them. ERPA states that any dispute, controversy or claim arising under, out of, or relating to the interpretation, application, or performance of this agreement, including its existence, validity or termination, shall be settled amicably by negotiation. If the invitation to negotiate is rejected, or if the Parties have not resolved the dispute within agreed number of days from the date of commencement of negotiation, either party may commence arbitration in accordance with clause indicated in the ERPA.

3.2.2.3 Description and common features of ERPAs

Definitions and interpretation

In the ERPA certain words have specific meanings. These words are called defined terms. The defined terms begin with capital letters and their specific definitions are set forth in Annex 2 of the ERPA. Whenever a word is capitalized, Annex 2 should be consulted in order to understand the meaning of the word. Some words are used both as defined terms and as non-defined terms (e.g. Deliver and deliver). When a word is a defined term it has

[3] USD 0.10 per certified emission reduction issued for the first 15,000 tonnes of CO2 equivalent for which issuance is requested in a given calendar year; USD 0.20 per certified emission reduction issued for any amount in excess of 15,000 tonnes of CO2 equivalent for which issuance is requested in a given calendar year.

the meaning given to it in Annex 2, and when a word is not defined it has its ordinary meaning.

Conditions precedent

Conditions precedents are used to set out the conditions that must be met by either the buyer and/or the seller before the agreement or certain parts of the agreement come into effect. In the ERPA, delivery and payment obligations do not come into effect until the conditions precedent have been met, whereas obligations to develop and register the project are binding from the time the contract is signed by both parties. Conditions precedent can benefit both the buyer and the seller by postponing certain obligations of the parties until the agreed upon conditions have been met. This can have the effect of limiting a party's liability for aspects of the agreement until certain risks (such as registration) have been overcome. It is important that the conditions precedent in a particular agreement be carefully assessed to determine their effect.

Parties may agree on multiple conditions precedent and these conditions precedent may reflect the specific needs of the seller as well as the buyer. They may include requirements as diverse as the seller presenting a draft project design document; either party obtaining a Letter of Approval; the buyer completing due diligence of the project; the seller completing due diligence of the buyer's creditworthiness; the seller securing financing for the project; or the project reaching certain project milestones.

It is important to note that if meeting a condition precedent is left to the discretion of a party (such as completing due diligence to the satisfaction of the buyer/seller), then that party could retain a unilateral right to walk away from the project, without liability, any time up until that condition precedent is met. This is also true if satisfying a condition precedent is within the control of one party (e.g. obtaining a Letter of Approval). Minimizing the number of conditions precedent and the timeframe within which conditions precedent must be met can help reduce the risk that a party will terminate the agreement because the conditions were not met. The obligation in clause 2.01(b) to "*use all reasonable endeavours to procure satisfaction of the Conditions Precedent in good faith as soon as practicable following the execution of this Agreement*" also minimises the risk of termination by a party. This language helps mitigate the possibility of the buyer or the seller delaying or acting in bad faith to avoid the contract entering into force. In practice, deliberate delay or bad faith may be difficult to prove, however, this general language does provide a safety net in the event either party fails to act as agreed.

A buyer may ask for a condition precedent that requires the seller to secure a formal written legal opinion stating that the seller will have full title to the CERs generated by the project. Such an opinion might offer comfort to the buyer but its real value is doubtful as many jurisdictions do not regulate the title or ownership of emission rights or CERs. To date, legal right to the CERs has been determined by applying the principles of general law of the jurisdiction in which the CERs are created. The issues of title and ownership of emission rights and CERs remain to be tested in national courts. Note that a seller liability may arise if a court finds the opinion to be incorrect or based on knowingly false or unsubstantiated information. Even if this is not a condition precedent, it is in the best interests of a seller to seek legal advice (but not necessarily a formal written, legal opinion) early in the

development of a project to review the sellers' right to the emission reductions. This point is also relevant to clause 6.02 "Seller's Representations and Warranties".

In the ERPA, notifications with respect to conditions precedent require the seller to notify the buyer once the conditions precedent have been satisfied. They also require the seller to notify the buyer if it has reason to believe that a condition precedent may not be satisfied.

Delivery and Costs

The clause defines: what is to be delivered; when delivery is to occur each year; how much is to be delivered; and where and how the CERs are to be delivered. It should be read in conjunction with the definition of Delivery.

What is to be delivered is clear – an amount of CERs equal to the Contracted CERs. Care must be taken in determining when delivery is to take place. Most contracts contain annual delivery obligations but shorter or longer time periods are also possible under the CDM rules. Compliance with the EU ETS commitments are currently assessed on 30 April each year, so most EU buyers request delivery early in the year. However, if the date is set too early (for example January), it may not leave enough time to get the CERs generated in December verified, issued and then delivered to the buyer.

Determining where delivery is to occur is principally influenced by how "Delivery" is defined. However, whether or not the buyer is listed as a project participant and who has communication rights with the Executive Board, can also affect where and how CERs are delivered. In the ERPA, delivery is defined as the receipt of CERs into a registry account nominated by the buyer. However, this is qualified in clause 4.01(d) which deems delivery to have occurred if the buyer does not have a registry account that can accept the CERs or fails to nominate an account. Clause 8.02 states that the buyer will be listed as a project participant. This allows CERs to be forwarded directly into the buyer's registry account – either a temporary holding account in the CDM registry if the international transaction log is not operational, or a national registry account if the international transaction log is operational. If clause 8.02 is amended and the buyer is not a project participant, then the CERs will be first forwarded into an account of the seller or a third party before they are transferred to the buyer. The international transaction log must be operational for this to occur. Clause 8.01 states that the seller has sole communication rights with the Executive Board. If this is amended to grant joint communication rights to the buyer and seller, then both parties may need to sign instructions telling the Executive Board where to forward the CERs. If the buyer has sole communication rights, the seller should avoid the possibility that it can only meet its delivery obligations if the buyer first undertakes certain actions, such as telling the Executive Board to forward CERs into its registry account.

Annex 4 lists some, but not all, of the project development costs that may be covered or reimbursed by the buyer. The seller can consider its costs in the early stages of the project development and seek contribution towards them either in the form of a grant or as an "advance" to be repaid by deducting these costs from the annual payments to be made by the buyer in accordance with a schedule. Clauses 4.02(b),(c) can be deleted if the buyer is not contributing to the project development costs.

If a seller requires funds to cover some of the project's early costs, requires additional capital, or if the terms of available financing are too onerous, it may decide to negotiate an advance payment for CERs. The seller may seek to discount the unit price received per CER is often discounted when advance payments are made, but the discount should not make the advance payments less attractive than other sources of financing. The seller can expect that the buyer will ask for some form of security for the money advanced so that if the project does not go forward, the advance payments will be repaid to the buyer. It is important that the repayment schedule for advance payments be set up with the needs of the project in mind.

The transaction may attract taxes or duties in both the buyer's country and the seller's country. Particular attention is to be paid to the potential VAT liability as well as any import or export taxes/duties levied on international transfers. It is always advisable to confirm the applicability of a certain tax arrangement by consulting with a local tax expert (and to review double taxation treaties). The ERPA template proposed a tax clause that aims at addressing the various scenarios of tax liability. With respect to VAT liability we propose various formulations that allocate VAT liability either to the Buyer or to the Seller, according to the outcome of negotiations.

The Executive Board shall also deduct fees that are referred to as the "Share of Proceeds". The Share of Proceeds includes transferring 2% of all issued CERs into an adaptation fund (except projects located in "least developed countries") plus an administrative fee for each CER issued. The administrative fee is currently US$0.10 per CER for the first 15,000 CERs issued per year and US$0.20 per CER for each additional CER issued per year. The registration fee for a project is calculated as the administration fee for the first year of a project. The registration fee is then deducted from the subsequent administrative fees for issued CERs. This means that if the project performs as expected in the first year, the share of proceeds to cover administrative expenses for that year will equal the registration fee, and no additional fee should be paid in that year.[4] It is important to make it clear which party shall be responsible for paying the various fees and taxes.

Obligations of the Parties

The ERPA contains various obligations for both parties. Article V repeats some of the key obligations found elsewhere in the ERPA and sets out additional obligations of both parties. The obligations of the parties should reflect the nature of the relationship between the parties. In most cases this is a buyer and seller dealing at arms length.

In most CER contracts, the seller and buyer are engaged in a simple sale and purchase transaction at arms length. This type of relationship does not necessarily justify significant buyer control or oversight of the project. If the buyer makes a significant advance payment, the seller might be expected to incur additional obligations. Additionally, given the uncertainties in the creation of the underlying asset (the CERs) and the regulatory and/or financial impact on buyers that may occur upon non-delivery, some buyers may also seek additional provisions (particularly if buyer remedies against the seller in the event of non-

[4] See http://cdm.unfccc.int/EB/023/eb23_repan35.pdf

delivery are limited). The parties may also consider certain inspection rights of the buyer at the project site or business premises of the seller.

The main obligation of the buyer is to pay for delivered CERs. If there are concerns over the creditworthiness of the buyer, an additional obligation to maintain a minimum credit rating could be considered. However, not all buyers are rated and so if this approach to additional security for the seller is not available, other means of assuring payment by the buyer can be considered. See clause 3.03.

3.2.3 Transfer of Funds

The key question that is specified in a project ERPA concerns the transfer of funds in exchange for CERs. This transfer could include an advance payment as well as payments in exchange of verified and issued CERs. Normally, the carbon buyer would like to be certain that the project CERs are safely delivered to his account in GHG registry and pay after that fact. In order to mitigate possible mistrust parties may agree to set up cash and carbon escrow accounts with a trustworthy carbon trust company, which sends cash and carbon simultaneously once both of these are deposited to its escrow accounts.

Clearly, the key element to having CERs delivered to the buyer is timely conclusion of monitoring and verification repots and their delivery to CDM Executive Board for issuance of CERs.

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