Internal Working Document – Final Version

Discussion Paper on North American and International Initiatives to Quantify Emission Reductions from On-Grid Renewable Electricity Facilities

An Overview of Developments Relevant to the CEC Working Group

Prepared by:

Envirochem Services Inc.

310 East Esplanade
North Vancouver, BC
V7L 1A4
Tel: (604) 986-0233

Prepared for:

Commission for Environmental Cooperation

Author: Martin Tampier, M.Eng.
<martin.tampier@telus.net>

29 November 2004

Table of Contents

Glossary

CCGT	Combined Cycle Natural Gas
CDM	Clean Development Mechanism (under the Kyoto Protocol)
CEC	Commission for Environmental Cooperation
EPA	US Environmental Protection Agency
GHG	Greenhouse gas
IEEE	Institute of Electrical and Electronics Engineers
ISO	International Standards Organization
JI	Joint Implementation (mechanism under the Kyoto Protocol)
MWh	Megawatt-hour
OECD	Organisation for Economic Cooperation and Development
RECS	Renewable Energy Certificates
RFP	Request for Proposals
RPS	Renewable Portfolio Standard
WRI	World Resources Institute

Background

The CEC Working Group on the Quantification of Environmental Benefits from Renewable Energy Operations convened in Washington, DC, at the end of September 2004. Since its last meeting in July 2003, numerous initiatives have emerged, or have become relevant to the working group's task. This document provides an overview of these initiatives, and describes possible implications for the working group, in preparation of the November 2004 workshop.

A previous background report had been completed by *Synapse Energy Economics*, the *Hélios Centre* and *Energy Matters* prior to the 2003 workshop. This report identified three main methodologies to quantify emission reductions from on-grid electricity generation:

1. Grid average – the average emissions per MWh for the national grid, or a region, are used as a baseline to quantify emission reductions from renewable sources of energy ("renewables").
2. Operating margin – the marginal generation unit is used to quantify emission reductions from renewables. This unit is the plant that comes on the grid last of all plants. Different plants can be on the margin, depending on the time of day and the season. This method requires some more complex modelling to anticipate which plant will be the marginal unit at which point in time (generally, the marginal unit is the most expensive plant required to fill current demand). It was noted during the 2003 workshop that this information is not always available, as for example in Alberta, Canada, information about which unit is producing when is not public.
3. Build margin – the emissions from planned generation plants are used to determine emission reductions from renewables. The build margin is often a natural gas plant, but can also be a mix of different plants, including coal, nuclear, or large hydro.

The background report also analyzed several national initiatives and programs and described their methodologies to quantify emission reductions from on-grid renewables. It was found that there are many different approaches. Most Canadian methodologies use the system average; Mexico prefers the thermal average, i.e., the average of only fossil fuel-based power plants, and the United States prefers the marginal dispatch approach, based on dispatch models. The report recommends using the marginal dispatch as the most appropriate methodology for quantifying emission reductions from renewables.

This present document elaborates on these previous findings, and puts them into an international context, while also updating national developments. It analyzes existing relevant initiatives that overlap with the task of the CEC working group, and makes recommendations for advancing the work on a common quantification methodology for North America. The recommendations flow from both the comparison and evaluation of current trends, as well as telephone interviews with about a dozen prominent international experts on methodology.

Findings

A large number of efforts are underway to quantify benefits from on-grid renewable energy operations. Virtually all efforts use slightly different approaches and no convergence between them can be observed at this point in time. The most relevant programs for the CEC working group are:

1. The Consolidated Methodologies of the Clean Development Mechanism's Methodology Panel [MethPanel]: Mexico is a CDM host country, and Canada is a buyer of CDM projects. Consistency with the CDM methodology is therefore desirable for both countries.
2. The World Resources Institute/World Business Council on Sustainable Development GHG Reporting Standards: The Corporate Reporting Standard has been formally adopted by Mexico in August 2004, and it is slated to be developed into an ISO standard. Whereas the Project Quantification Standard, which is more relevant to the CEC work, is still under development, it may also be turned into a standard by the Institute of Electrical and Electronics Engineers.
3. The Canadian Offset System: there are indications that renewable energy could be included in the Canadian Offset System under the Kyoto Protocol. This would mean that the quantification methodology adopted would have a strong impact on Canadian projects.
4. Ongoing work by the National Renewable Energy Laboratory for the US Environmental Protection Agency to develop a quantification methodology for NO_x emissions within the NO_x State Implementation Call. This methodology could be expanded to other emissions later on.

A draft ISO standard on GHG offsets is merely procedural and has no bearing on the CEC work. Several other approaches and models exist in Canada, Mexico and the United States, which should be considered as well. Two US approaches, one developed by the Tellus Institute and one by the Lawrence Berkeley National Laboratory, have fed into the CDM and WRI processes. All relevant initiatives that were identified since the previous CEC working group report was completed in 2003 are described in Appendix 1.

A strong drive towards more standardization of baselines, as opposed to project-based, individual emission reduction assessments, is present. Several initiatives distinguish between corporate and project-based emissions accounting. Corporate accounting usually recommends less complicated methodologies, such as taking a country grid average emissions factor for electricity production, using the official numbers issued by the International Energy Agency, for example. This would apply to both energy efficiency projects and on-site renewable energy generation. More complex quantification methodologies are recommended for project-based emission offsets. There is also a trend to allow small-scale projects (15 MW or less) to use less complicated methodologies than larger scale projects. Generally, emissions are not quantified using a life-cycle approach, but baselines merely reflect on-site emissions due to the combustion of fossil fuels, i.e., from the production of electricity. This would mean that emissions occurring outside the period the power plant is in operation, such as for the manufacturing of wind turbines, or for the transport of biomass, are not considered for the calculation of emission reductions.

There is a clear trend away from simplistic methodologies, such as using the grid average, towards using the operating margin, the build margin, or a combination of both (combined margin). However, the methodologies to calculate these margins vary considerably. A range of options are being suggested, ranging from marginal averages or proxy factors to complicated models that consider regional energy planning and price forecasts for fossil resources. Very complex models are being criticized for being very expensive to implement, requiring large amounts of data, and being less transparent. Simpler models are seen as yielding unrealistic results in some situations. Some methodologies therefore represent a compromise between a very simple approach and sophisticated modelling. The main types of methodologies are:

1. Proxy technology (for example, Combined Cycle Natural Gas) or another set; emission factor that applies to all projects;
2. Grid average (national, regional, or local);
3. Fossil average (fossil fuels only) ;
4. Weighted marginal average (marginal units only);
5. Operating margin (based on annual, monthly, daily or hourly load curve);
6. Dispatch models (based on price of generation);
7. Complex models (based on pricing, energy and transmission planning);
8. Build margin (last five years or latest 20 percent added);
9. Build margin (projected additions); and
10. Combined margin (combination of operating and build margin).

Any methodology is merely an approximation of the amount of emissions really displaced by on-grid renewable energy generation. It is impossible to fully attribute an emission reduction from reduced generation of fossil fuel-based plants to a specific renewable energy plant. Changing weather and consumption patterns, electricity imports and exports, and data availability issues do not allow for a precise determination of emission reductions due to the addition of renewable energy generation. Any methodology is therefore a compromise and the emission factors derived merely depend on the support and sanction of the program administrator, agencies and those using the methodology to be considered valid. However, certain methodologies are seen as giving a more realistic picture of what is really displaced on the grid than others. The question of selecting a methodology then becomes one of balancing model transparency, costs and external interests, rather than being one of achieving the highest scientific accuracy.

Ideally, all fields of emissions accounting, including corporate reporting, national emission inventories, and emission trading programs, should use the same methodology to quantify emission reductions from renewable energy operations. Whereas experts believe that different methodologies will ultimately converge, many of them are not very concerned that different methodologies are applied in different fields at this point in time.

Table 1 provides an overview of both the initiatives identified in the 2003 background report and this present report.

Table 1 North American and International Initiatives and Quantification Methodologies (including examples from 2003 report)

Initiative	Methodology	Relevance for CEC work	Comments
Canada			
GERT	Not specified	o	Accepts various methodologies
PERRL	Marginal dispatch	o	Use ICF IPM model
Wind Power Production Incentive	1.15 t of CO_2/MWh	-	Exact methodology unknown
Pembina Institute	System average	-	Also used build margin in British Columbia
BC Hydro Green Certificates	Proxy plant	-	360 kg of CO_2/MWh
Offset System	Proxy plant (suggested)	++	Combined cycle natural gas
Ontario Emissions Trading Set-Aside	Emission factors for NO_x and SO_2	+	Seasonal and half-daily determination of coal on margin
Federal Green Power Procurement	Half-daily or annual average	+	Also use system average for Alberta as no hourly data available
Mexico			
CONAE	System average	-	Used for energy efficiency
FIDE Estimates	System average	-	
ATPAE	Thermal average/build margin	o	Similar to current CDM methodology
Comisión Federal de Electricidad	Marginal rate	-	Exact factors not in the public domain
United States			
Ozone Transport Commission	Dispatch modeling	o	
ISO New England	Dispatch modeling	o	Similar models used in other pools
EPA/ICF's IPM Model	Dispatch modeling	+	Also used in Canada and Mexico
SO_2 and NO_x trading	Set emission factor	-	Outdated
NREL NO_x work	System average or dispatch model	+	May be expanded to CO_2
RGGI	Under development	++	May adopt ICF model
LBNL MAGPWR	Dispatch model	+	
LBNL MBASE	Operating or build margin	+	Has influenced WRI work
Oregon Climate Trust	Operating margin (set factors)	+	Regional emission factors are a model for the CEC to follow
Energy 2020	Dispatch model	++	Also used by Canada
International			
CDM	Combined margin	++	Combines operating and build margin
OECD/IEA	Combined margin	++	Was adopted by CDM MethPanel
UNIDO	System average	-	For CDM/JI projects
UNCTAD	System average	-	Use IEA country factors for Eco-efficiency indicators; moving to-wards more complex methodology
PROBASE	Dispatch model	+	Models entire power system
WRI Project Standard (draft only)	Build, operating or combined margin	++	Provides 3 options, one of which is similar to CDM methodology
ISO Standard	n/a	-	Does not define methodology
IEEE GHG Standard	Under development	++	Linked to WRI work

- not relevant; o of little relevance; + somewhat relevant; ++ very relevant

Discussion and Recommendations

The amount of work that has been accomplished at the national and international levels suggests that the CEC should not endeavour to replicate this work, but rather draw on it and simply adopt one of the existing methodologies, possibly with slight adjustments to the North American situation. The methodology chosen should fulfill the following basic requirements:

1. It must allow for regional emission factors to be calculated that the CEC could post on its web site, thus reducing transaction costs. Alternatively, an Internet-based modeling tool could be provided on the CEC web site for a user fee.
2. It should be compatible with the initiatives considered most relevant to North America (see above).
3. It should be applicable to offset trading, to quantify emission reductions gained through government programs, and to environmental claims related to products made with renewable electricity or renewable energy certificates. It should also be fungible with national GHG accounting.
4. It should be able to take into account financial impacts of emissions trading, like 4-pollutant trading, as this may influence the dispatch of plants in the future. The combined price of emission allowances can reach US$45 per MWh.

Conclusion: The working group should look into adopting or adapting an existing methodology, rather than developing its own.

A number of design options need to be addressed by the CEC working group to select the most suitable methodology:

Basic methodology choice: The CEC can opt to either select a simple emission factor that would apply to all projects, such as the emissions of a state-of-the-art combined cycle natural gas plant. This would be the simplest approach with the least implementation cost. Such a factor is being suggested for the Canadian Offset System, although discussions about these issues are still ongoing (fall 2004). Using the grid average, or the average of all thermal generation, as has been suggested for Mexico, is another simple option. However, these approaches do not seem to be appropriate for the following reasons:

1. There is no support for simplistic approaches within the United States.
2. Relevant international initiatives, such as the CDM or the WRI process, do not support simple approaches, apart from for small-scale projects.
3. Using very simple quantification methods raises concerns of compatibility with national emissions inventories and projections. As renewable energy gains larger market shares, the emission reductions calculated using simple methodologies may not match sufficiently what really occurs on the grid, leading to discrepancies between offsets granted and actual emissions displaced.

Comparisons have been made by the Tellus Institute for selected North American regions to evaluate the differences in emission reductions calculated using different methodologies. The result for the system average with the exclusion of low-cost/must-run resources (0.80 g CO_2/kWh) gave nearly the same result as a dispatch analysis for the main national grid (0.81 g CO_2/kWh). On the other hand, in one of the sub-national grids (Baja California North) the dispatch method result was 70 percent higher (1.7 versus 1.0 g CO_2/kWh) [Tellus 2004]. Lawrence Berkeley National Laboratory compared results of several calculation models for California [LBNL 2002]. They also confirmed that average emission factors do not adequately reflect actual emission reductions. In addition, seasonal changes in the power mix were significant, such that the report recommends accounting for variations in emission intensities throughout the year. Berkeley Labs used the Elfin model, which was developed for California in the 1980's, and a load curve-based spreadsheet, with somewhat simpler calculation algorithms than Elfin. Both models resulted in very similar marginal emission factors. Then, the National Renewable Energy Laboratory used three methodologies to calculate emission reductions from energy efficiency projects. Their recommendation is to use dispatch models for larger-scale projects, whereas small-scale projects could use the average of the NERC sub-region (see Appendix 1, section 2.1.2).

Conclusion: A more complex methodology than grid average is required, either based on the CDM/WRI models, or on dispatch modelling.

Geographic aggregation: Generally, the regional scope of the dataset to be used for emission reduction calculations is not predetermined in existing methodologies. The CEC therefore needs to determine at which level to set this delimitation. Table 2 shows some of the options available for regional scope.

Table 2 Options for Setting Regional Electricity Boundaries [Tellus 2001, p. 44]

Regional boundary	**Advantages**
Power pool	Methods can reflect how system and market actually operates
NERC region	Can be most accurate, especially where transmission constraints are limited
Provincial/state level	Easier for proponents to identify the region in which they belong
National	Most relevant for fully-interconnected and smaller countries
Multi-national	Highly-interconnected regions (e.g., Southern Africa Power Pool)

Throughout North America, strong regional differences mean that the national grid cannot be used as the aggregation level. While the regional grids are all interconnected, these ex- and imports could be accounted for when calculating emission reductions, and the following integration levels are recommended to strike a balance between minimising interconnectedness with neighbouring grids and representing the particular generation mix for each sub-grid:

- The <u>provincial</u> level seems most appropriate for the Canadian situation, with the exception of isolated grids, as provinces maintain their own power grids, with significant differences between the provinces. The merits of combining smaller maritime provinces into one region should be examined.

- Mexico currently contains four semi-autonomous regions for grid operation and power plant operations. Largely due to limited transmission connections among them (Baja California South, Baja California North, the Northwest, and the rest of the country), these regions seem the most appropriate level of regional integration.
- The United States has several levels of integration of its power grid: the NERC Regions (administrative regions), the Power Pools, and EGRID Sub-Regions. The 27 EGRID Sub-Regions seem most appropriate for regional integration for the CEC work as they strike a balance between local differences and relative independency of the regional grid.

If there is significant trade between grid regions, e.g., a dedicated transmission line from Manitoba to Ontario, as is presently being suggested, then this generation should be excluded from one province's generation and included into the power generation mix of the province that purchases this generation. For Alberta and British Columbia, this would mean British Columbia would have to take an emission penalty for importing cheap coal-based generation from Alberta during off-peak hours. Quebec's large hydropower exports to New York would be treated as electricity generated inside the United States. Likewise, imports and exports between Mexico and the United States would have to be treated as being located in the importing country. This allocation of imports to the importing region is in line with the proposed consolidated methodology for zero-emission renewable energy projects within the CDM.

Conclusion: Regional grids should be used to calculate emission reductions. Emissions related to power imports should be attributed to the importing region.

Build or operating margin: A new renewable energy facility will have an immediate effect on electricity generation by displacing other sources on the margin. It will also have effects on plans to build or replace power plants in the future. Some approaches, such as the CDM Consolidated Methodologies, try to combine these effects into a combined margin approach, using a default 50/50 share for build and operating margin displacements. In the WRI/LBNL approach (now outdated road test draft), intermittent plants only displace power at the operating margin, whereas plants generating firm power, such as biomass and geothermal, only displace at the build margin. However, the assumption that intermittent plants do not affect the build margin is wrong. For example, wind power plants usually only require about 30 percent of their annual generation to be backed up by other plants, as the combination of many wind farms over a large area increases the reliability of intermittent sources. This could be integrated into the CDM methodology by changing the weighting between build and operating margins, for example to a 35/65 relationship. On the other hand, the build margin could also be integrated into the operating margin if the latter is extrapolated over several years (see Appendix 4 for some considerations on the build margin). Calculating the operating margin for at least ten years would include effects on the build margin if future developments in the generation mix are accounted for. This extrapolation of the operating margin would have to be based on a "business as usual" scenario that only includes scheduled additions of renewable energy projects, such as those mandated by an RPS. If the emission reductions from the projects mandated through an RPS themselves are to be examined, the same operating margin could be used, but they would not be considered additional in Kyoto terms.

Incremental changes in effects of the "next" plant: One small renewable energy plant may not have major effects on operating and build margins. However, a large number of these plants built over several years will influence both how the grid is powered, as well as which new plants will be able to be built and gain power purchasing agreements. This means a plant going online today may have different effects from a plant that comes online in two years, after a number of other renewable energy plants have been built and started operating in the mean time. For example, a critical amount of renewable energy plant capacity may be required to avoid the construction of a new natural gas-powered plant. The only way to represent such changes over time would be to integrate a project database into the model, or to update the model regularly and frequently (for example, annually) to integrate changes in the background mix.

Conclusion: Not every renewable energy plant will have the same displacement effect. This effect will change with the number of plants coming online. The model chosen by the working group should therefore incorporate such changes, possibly simply by being updated each year.

Different technologies: Intermittent renewable energy technologies have different generation profiles. For example, a solar PV plant will only produce power during the day, whereas a tidal power plant will generate power according to the moon phases. Wind and wave will only generate power when the wind blows. These different profiles will in many cases lead to different amounts of power being displaced from marginal sources. California, for example, has its power consumption peak in the summer, during the hot afternoon hours. This is when wind power produces least electricity, as there is usually little wind during those times, whereas solar PV produces at its peak, thus displacing a maximum of generation at the operating margin. These increased emission reductions of solar PV should be reflected in calculation methodologies. On the other hand, if coal would be on the margin during the night, using a common profile for all renewable energy sources would underestimate the emission reductions from wind power plants. Such issues will become even more relevant should the same methodology be applied to seasonal NO_x trading, for example. For Ontario's NO_x and SO_2 trading system, seasonal and half-daily (day/night) emission factors are used to approximate when coal-fired generation is on the margin. As a minimum, a seasonal load profile should therefore be used to calculate emission factors for each technology.

Conclusion: The use of seasonal, half-daily or hourly load profiles is recommended, and emission reduction factors should be calculated separately for each technology.

Large and small: Some methodologies recommend using simplified methodologies for smaller projects to reduce transaction costs. However, if the CEC publishes regional emission factors, this argument fails as transaction costs will be low for all projects. If an Internet-based model was used to calculate emission reductions, user fees could be based on annual generation, hence also reducing costs for smaller projects. Another argument is that small plants have little effect on build margins. However, they can be expected to have an incremental effect, and many small projects should have the same effect as one large project resulting in the same amount of generation. It is therefore not necessary to apply different factors to projects of different sizes.

Conclusion: The same emission factors should be used for small and large renewable energy projects.

Baseline revision and forecasting: An important question is how often baselines or emission factors should be reviewed. Changing these factors creates some insecurity as to the future amount of GHG emission offsets that a project can obtain. Often, statistical data on the generation mix and related issues can only be gained for periods one or two years in the past and before, making operating margin calculations for the current year less accurate. Modelling future generation portfolios would require incorporating some knowledge about planned plant additions and policies to support the development of renewable energy. These parameters usually do not change quickly, but major changes can be expected within a five-year time horizon. Ideally, the model should therefore be updated annually, but at least every five years.

This issue is closely related to the question of using ex-post and ex-ante calculations of emission reductions to create emission credits. Under the Kyoto Protocol, seven or ten-year periods are used for granting offsets to renewable energy projects. The forecast emission reduction based on CEC emission factors should therefore remain valid for either of these periods. If they are updated annually, projects should use the most recent factors, but if factors are adjusted in the future, they should not have to increase or reduce the amount of offsets generated by the project. For environmental claims, such as those related to renewable energy certificates, the preliminary forecasted numbers could be declared valid for at least five years, and would only have to be revised in five-year intervals.

As overall emissions of the electricity system can be expected to decrease over time in most regions, frequent updating may result in lower emission factors over time, with earlier renewable energy plants obtaining higher benefits than those constructed later.

Conclusion: The baseline should be revised annually, or at least every fifth year.

Possible options: There are several possibilities for the CEC working group to proceed from here. Several options—discussed in detail in Appendix 1 - are discussed below, with specific recommendations:

- The CDM methodology uses a combined margin approach includes both operating and build margin effects. It is flexible enough to incorporate different effects of specific technologies, such as intermittent wind, by varying these factors. However, it would not differentiate technologies based on their seasonal or hourly generation profiles. Using a dispatch model based on load profiles would account for such differences. As such a model exceeds the CDM requirements it can be expected to be eligible to calculate emission reductions for CDM projects.
- The WRI process should be closely monitored by the CEC working group. The current (but outdated) Road Test Draft offers three options to calculate project emission reductions: While the "project specific" option is a build margin approach and not considered sufficient for North America, the multi-project baseline fails to recognise build margin effects of intermittent resources. It distinguishes firm and non-firm resources in a complicated way, although both can be expected to have both build and operating margin effects. It recommends using averages, rather than load and generation profiles and therefore does not result in a fair allocation of emission reductions that produce most of their power during peak hours. The third option is essentially the same as the CDM methodology. A dispatch model would therefore be compatible with the current draft of the WRI methodology as well. A final version of the WRI methodology is expected by mid-2005.
- The European PROBASE model is fairly expensive to implement (at least 3 months of consulting work per country, and probably far more than that in the United States). However, it is also very precise and even takes into account transmission constraints and future fossil fuel price shifts. It is an Internet-based tool and would allow for each project manager to input project data and thus obtain emission reduction numbers from the model. A fee-based use of this tool could help recover some of the cost for the establishment and maintenance of the model. The model would also be able to derive seasonal emission factors for different technologies. Similar models, such as the Energy 2020 model, exist for North America.
- The ICF Model is a dispatch model that uses monthly load profiles, and incorporates single plants, which are dispatched based on pricing assumptions and transmission constraints. Like PROBASE, it is considered fairly precise and can also model future generation mixes. The model exists for all thee North American countries, but would have to be refined for Mexico if selected by the CEC working group. It can model seasonal differences between solar PV and wind, for example, as it able to utilise monthly, or even hourly dispatch data. The US model already uses the NERC sub-regions recommended for this work. The Canadian model is currently being updated to the same level of integration as the US model, as Environment Canada wants to model policy impacts of cross-border trading of SO_2 and NO_x allowances.
- Lawrence Berkeley's MAGPWR model seems suitable for the CEC work. Like the previous two models, it can model future changes in the generation mix, thus avoiding the need for calculating a separate build margin. It is able to model hourly dispatch, and thus differentiate between various technologies. It does not model the grid at the plant level, but combines all plants of a given technology,

which reduces complexity. It can be used for different regional levels of integration, and electricity imports and exports can be programmed into the model. It has only been run for California so far.

- The LSU Center for Energy Studies Modeling Approach suggested by NREL for NO_x emission calculations seems to be another possible option for the CEC working group. This model uses hourly dispatch data, and models the grid at the single plant level. Plants are dispatched based on economics, and the hourly data allow for the different treatment of each renewable energy technology.
- Canada's methodology for NO_x and SO_2 trading in Ontario and for purchasing green power in Ontario is a somewhat simplified approach that emulates dispatch modeling by deriving seasonal emission factors that are further refined for day and night time. The working group would have to determine whether the accuracy of this method is sufficient for its needs.
- A number of other models are available that could be used by the CEC working group. For example, the Canadian CANPLAN model is being used to determine future generation needs. The Northwest Power and Conservation Council uses the AURORA model, which also forecasts effects of renewable energy plants on the future build and operating margin. Several more proprietary models exist.

Conclusion: One of the existing models/methodologies should be selected or adapted.

Selecting the right model: The CEC should now select several (at least four) regions in North America to test and compare the models. As PROBASE does not contain data for North America, it could only be used in a regional trial. Other models exist in the United States only, and the ICF model is available in all three countries. The working group should examine and compare the results obtained from models considered eligible for modelling emission reductions from renewable energy facilities in North America, and make a judgment as to the appropriateness of the results obtained. Regions that are known to pose problems to the calculation of emission reduction benefits and where methodologies could be road-tested include:

- United States: California, New England (considerable imports and seasonal changes)
- Canada: British Columbia or Quebec (high share of large hydro)
- Mexico: Baja California North (Tellus test runs resulted in different results using different models)

Conclusion: Several models or methodologies should be pre-selected by a technical sub-working group, or a consultant. They should then be road-tested in several North American regions before selecting the one to be used.

* * *

References

Tellus 2001 Lazarus, Michael *et al.* 2001. *Project Baselines and Boundaries for Project-Based GHG Emission Reduction Trading—A Report to the Greenhouse Gas Emission Reduction Trading Pilot Program.* The Tellus Institute, April.

Tellus 2004 Kartha, Sivan *et al.* 2004. Baseline recommendations for greenhouse gas mitigation projects in the electric power sector. *Energy Policy* 32, 545–566.

LBNL 2002 Marnay, Chris *et al.* 2002. *Estimating Carbon Dioxide Emissions Factors for the California Electric Power Sector.* LBNL-49945, Ernest Orlando Lawrence Berkeley Laboratory, Environmental Energy Technologies Division, August.

Appendix 1: Short Descriptions of Relevant Initiatives

International Initiatives

United Nations

The Kyoto Protocol's Clean Development Mechanism (CDM)

Description: The CDM allows developed nations that have committed to GHG emission reduction and limitation targets under the Kyoto Protocol to reach part of their commitment by buying offsets from projects realized in developing country Kyoto signatories that have no binding targets. The CDM Executive Board, supported by its MethPanel has released Consolidated Methodologies that can be used as a standard baseline calculation method.

Methodology: Historically, a mix of methodologies was used for CDM projects: build and operating margin (a term used to include both grid average and marginal dispatch), as well as a combined margin approach composed of both. In order to start a process of harmonisation of methodologies per project category (a first step in the direction of baseline standardization), the CDM-Executive Board requested the MethPanel to prepare consolidated methodologies. On June 16, 2004 the MethPanel submitted the first two proposals for such methodologies: for landfill gas project activities and for zero-emissions grid-connected electricity generation projects based on renewables. The draft consolidated methodologies were made available for public comments on the unfccc.int web site. The Panel recommends that the consolidated methodologies, once approved by the Executive Board, could replace previously approved methodologies in the project categories concerned.

According to the consolidated methodology, the emission displacement from renewables must be calculated using a **combined margin approach**:

- As a first step, project developers must determine the operating margin. This can be done using following methods: a) Simple (grid average including electricity imports, but excluding low-cost and must-run generation), b) Simple with Low-Cost/Must-Run Adjustment (including low-cost and must-run generation, to reflect the number of hours per year that these sources are operating on the margin), or c) Dispatch Data Analysis. The Simple OM method can only be used where low-cost/must run resources constitute less than 50 percent of total grid generation in: 1) each of the five most recent years, and 2) based on long-term normals (e.g., 30-year or 50-year averages) for hydroelectricity production.
- As a next step, the build margin must be determined. This emission factor is calculated as the generation weighted average emission factor of either the five most recent or the most recent 20 percent of power plants built or under

construction in the grid (whichever average annual power generation in MWh is greater). The build margin emission factor is calculated on an ex ante basis; only projects with a capacity of more than 60 MW must do an ex post update annually during the crediting lifetime.

- In the third and final step of this consolidated methodology, the OM and BM are combined as a weighted average of both. By default the weights are 50 percent OM and 50 percent BM, but these weights could differ from project to project. In the proposed consolidated method, an alternative weighting is possible depending on the project circumstances, but it is noted that more analysis on this issue may be necessary.

For example, the build margin may be assumed to be natural gas, but has to be calculated based on actually built plants, or plants currently under construction. The methodology defines further requirements for the additionality of a project. The methodology may not be applicable to large-scale hydro projects as a decision about the relevance of methane and CO_2 emissions caused by hydro projects is outstanding. If these are thought to be relevant, a separate methodology may have to be developed.

The **landfill gas methodology** allows for the use of calculations applicable to small-scale projects for generation capacities that equal or are less than 15 MW. It does not specify the baseline methodology to calculate the emission displacement of electricity from landfill gas.

The COP-7 conference in Marrakesh decided that simplified methodologies can be applied to **small-scale projects**, and these methodologies were adopted at COP-8. The methodology for small-scale on-grid renewable electricity generation can be used for units of max. 15 MW capacity (for co-firing, the entire unit must not exceed 15 MW if the small-scale methodology is to be applied; for biomass cogeneration, the maximum combined capacity may not exceed 45 $MW_{thermal}$). Two options are given to calculate the emissions displaced by the renewable energy unit:

(a) The average of the “approximate operating margin” and the “build margin,” where:
  (i) The “approximate operating margin” is the weighted average emissions (in kg CO_2e/kWh) of all generating sources serving the system, excluding hydro, geothermal, wind, low-cost biomass, nuclear and solar generation;
  (ii) The “build margin” is the weighted average emissions (in kg CO_2e/kWh) of recent capacity additions to the system, which capacity additions are defined as the greater (in MWh) of most recent (generation data for the most recent year they are available for), 20 percent of existing plants or the 5 most recent plants;

OR,

(b) The weighted average emissions (in kg CO_2e/kWh) of the current generation mix.

Relevance: The CDM is very relevant to Mexico, which is a CDM host country, and also to Canada, which intends to buy some 50 million tonnes of offsets in the international market during the first Kyoto Period (2008 to 2012). The field of application is national emission inventories, but also company reporting and compliance in cases where corporations directly buy CDM credits to remain within their emissions allocation. The

CDM has a lot of weight in discussions related to emission reduction quantification as it is the main international emissions trading program, together with Joint Implementation, and is based on international consensus involving a large number of countries.

Discussion: This methodology is mainly based on the input from the Tellus Institute (see below). It is flexible in terms of allowing a different allocation of build and operating margin to intermittent resources, as they usually have a smaller effect on the build margin due to the need of backup power. It also allows for the use of dispatch modelling to determine the operating margin. Whether it would allow for the use of a ten-year operating margin forecast at the expense of the build margin is unclear, but detailed modelling is expected to be accepted by the CDM MethPanel.

Documentation: Draft—approved baseline methodology: "Consolidated baseline methodology for zero-emissions grid-connected electricity generation from renewable sources," UNFCCC/ CCNUCC, CDM—MethPanel, 28 May 2004.

Draft – approved baseline methodology: "Consolidated baseline methodology for landfill gas project activities," UNFCCC/CCNUCC, CDM MethPanel, 28 May 2004.

Appendix B of the simplified modalities and procedures for small-scale CDM project activities: Indicative simplified baseline and monitoring methodologies for selected small-scale CDM project activity categories, Chapter I.D. – Renewable electricity generation for a grid.

Web site: http://cdm.unfccc.int/methodologies/inputsconsmeth

Contact: Jane Ellis (member of UNFCCC MethPanel), OECD Environment Directorate, Global and Structural Policies Division, Paris; e-mail: <jane.ellis@oecd.org>; ph (+33 1) 45 24 15 98

UNIDO

Description: The United Nations Industrial Development Organisation's guidelines have been prepared for project developers seeking to develop CDM or JI projects in the industry, energy, and possibly other sectors, where projects aiming at reducing GHG emissions can take place. The guidelines are intended to be applied in the planning stages of an emission reduction project to support the work involved in preparation of the project design documentation for registration.

Methodology: The methodology uses the grid average emission factor. This factor needs to be recalculated for every year in which carbon credits are to be created, i.e., future changes of the electricity background mix must be considered, not just the present mix.

Documentation: Guideline Document: Methodology for Baseline and Additionality Analysis for Multiple Project Categories. United Nations Industrial Development Organization, Vienna, July 2004

Relevance: This document was developed for CDM and JI projects. However, as the CDM MethPanel has developed its own standard methodologies, it may be of limited influence. It is largely compatible with the WRI standard.

Discussion: The methodology is very simple and will most probably not deliver results that are in line with national inventories, nor are they reflective of regional differences in North America. It is not seen as being acceptable due to the strong preference for more complex calculation methods.

Web site: http://www.unido.org/en/doc/4224

Contact: Marina Ploutakhina; Industrial Development Officer, Energy Efficiency and Climate Change, UNIDO (+43-1)-260-26-5051; <mploutakhina@unido.org>
Ingo Puhl; Michael Klein 500 ppm, <mklein@500ppm.com>
(+49 721) 6105 530 Karlsruhe; (1 240) 441-7963 Ingo Puhl Washington
<ipuhl@500ppm.com>

UNCTAD

Description: UNCTAD was called upon in 1998 by the Intergovernmental Working Group of Experts on International Standards to develop a methodology for corporate environmental accounting and reporting. This work resulted in a number of eco-efficiency indicators, which also include "Global warming emissions per net value added."

Methodology: The UNCTAD Manual on eco-efficiency indicators uses regional emission factors for electricity generation. The Manual stipulates that renewable energy is considered to have no GHG emissions. Electricity derived CO_2 emissions are based on the technology and fuels used in a specific country (the background electricity mix). Values are derived from data provided by the International Energy Agency[1] (see Table A1), which are average factors based on power sector emissions in relation to total annual generation. The Manual requires that country-specific emission factors be used when available.

Table A1 Electricity-derived CO_2-Emission Factors for North America Used for the Determination of UNCTAD Eco-Efficiency Indicators

Country	Grams of CO2/kWh
Mexico	527
Canada	196
United States	514
OECD North America	476

[1] IEA data are calculated using the IEA energy databases and the default methods and emissions factors from the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*. They are updated annually in September.

The manual allows for the use of offsets, but requires that they be certified by a national certification body. The methodology implies that the same methodology is used to calculate emission reductions from both increased and decreased electricity use, and alternative generation with renewables.
Relevance: UNCTAD's work is meant to be used by corporations for environmental accounting and disclosure of a company's environmental performance. It is therefore relevant to corporate energy efficiency and renewable energy projects, as well as renewable energy certificate purchases and related environmental claims. Corporations may pay special attention to the Manual if investors use them to monitor environmental performance and the achievement of emission reduction objectives.

Discussion: The methodology is very simple and will most probably not deliver results that are in line with national inventories, nor are they reflective of regional differences in North America. It is not meant for, or seen as being acceptable to calculate emission reductions from projects due to the strong preference for more complex calculation methods.

Documentation: A Manual for the Preparers and Users of Eco-efficiency Indicators, Version 1.1. UNCTAD/ITE/IPC/2003/7, United Nations Conference on Trade and Development, New York and Geneva, 2004

Web site: www.unctad.org

Contact: Constantijn Bartel (UNCTAD, Geneva), (+41 22) 917 5875; <Constantine.bartel@unctad.org>

Other International Initiatives

PROBASE

Description: The project "Procedures for accounting and baselines for projects under Joint Implementation and the Clean Development Mechanism" (PROBASE) was accepted in the Fifth Framework Programme "Energy, Environment and Sustainable Development" of the European Commission in May 2000. While the Conference to the Parties had set a framework on baseline determination, many technical details were left unclear. The project's objectives were therefore to develop recommendations to policy-makers on operational procedures for JI and the CDM, including baseline determination and accounting of emissions reductions; to explore means of standardizing baselines (on a voluntary basis) by producing a matrix of context-specific benchmarks; and to design an electronic baseline manual for project developers and validators. PROBASE was finalized in December 2002.

Methodology: PROBASE has developed, among others, a structure for an Internet-based manual for calculating emission reductions from CDM and JI projects that displace heat or electricity, called e-SEREM (Smart Emission Reduction Estimation Manual). This Manual takes into account a variety of parameters, including the country or region where the project is situated, whether the project is small or large scale, whether the project displaces base, average or peak load electricity, which sector the project is part of (electricity or heat), and whether the project is on or off grid. The manual can be used to calculate project emission reductions in Russia, South Africa and Indonesia, which were case study countries in the PROBASE study. The baseline emission factors are derived from two models: the comprehensive, bottom-up model PERSEUS and a simplified version Reflex, both developed at the University of Karlsruhe (Germany). PERSEUS models the complete energy sector of a country, including resources and generation technologies. It extrapolates current and future technology options, and creates a dynamic baseline based on a cost-optimised application of these technologies from project inception to the end of the period during which emission reductions are created through the project. PERSEUS also includes seasonal and daily load profiles. Finally, it can take decisions about future scenarios as defined in national energy plans into account. The model uses set energy demand assumptions over 20 years. If this data had to be updated it would currently have to be done through Karlsruhe University (Germany), and all such work depends on available funding. *Reflex* is another model incorporated into e-SEREM, which is a more simple alternative to PERSEUS. Reflex can model the energy system of a country, region, or economic sector in a given country. It can also deliver emission displacement figures depending on whether electricity is displaced as base, average, or peak load (this has to be selected by the user). Reflex considers electricity demand projections, as well as transformation and distribution losses.

Emission reductions from small-scale projects could be determined using a national average emission factor, but the PROBASE report does not encourage the general use of these factors to avoid giving away too many emission credits to projects with lesser emission reduction effects.

Relevance: There is a general tendency towards more standardization of baselines. PROBASE attempts to explore standardization options that both offer the benefits of streamlining of procedures and that deliver baselines sufficiently representative for the business-as-usual case of a CDM project. This exploration has partly been carried through the modelling of a national or regional grid and deriving emission reduction factors from the macro- or meso-economic and policy context. Most existing CDM methodologies are bottom-up approaches and try to quantify emission reductions from a project perspective, but some of the methodologies aim to derive macro- or meso-baseline figures for a particular CDM host country (e.g., the Wigton wind farm project; the El Gallon hydro energy project), which resemble multi-project baseline emission factors as derived in the PROBASE context.

So far, the PROBASE method and software can only calculate emission reductions for Russia, Indonesia and South Africa, as these countries were selected as case study countries, but PERSEUS model structure and broad country data availability enable an expansion of the model's application to other countries as well, although this could imply relatively high upfront costs (adding one country usually requires three months of work), which would replace project-specific costs though as the multi-factor emission factors thus derived can be used by a multitude of projects.

The PROBASE team will seek funding to expand the model to other countries. Given the current trend towards standardization of CDM baseline methodologies, it seems likely that in the future multi-project baseline emission factors will become available for particular project types in particular host countries. The PROBASE method and software would fit in this trend. In this context, using PROBASE on a fee basis would enable preparing such multi-project baseline factors for several CDM projects as the fees would cover the up front development costs.

Alternatively, a fee-based application of PROBASE-like methods would have two advantages: first, baseline costs are spread among all projects that use the baseline factors, and, second, it properly deals with the free rider issue that has arisen at the moment when project developers use already approved methodologies, which have been developed and paid by the first movers.

Discussion: PROBASE is the most exact model among those discussed here. It does require a relatively large up-front investment to be set up and maintained, but costs could be recovered through user fees. It allows for different generation profiles, i.e., the allocation of different emission reductions for technologies that mainly work during peak consumption, such as solar PV in California. It only uses the operating margin, based on a price-based dispatch model, but extrapolates to future years, thus incorporating the build margin into the assumptions for future plants to be built.

Documentation: Procedures for Accounting and Baselines for JI and CDM Projects. EU Fifth Framework Programme Sub-programme: Energy, Environment and Sustainable Development - Final Report. PROBASE, February 28, 2003

Web site: http://jiq.wiwo.nl/probase/index.htm
e-SEREM: http://e-serem.epu.ntua.gr/

Contact: Wytze van der Gaast; Foundation Joint Implementation Network (JIN); ph (+31 50) 309 68 15; e-mail: <jin@jiqweb.org>
Catrinus J. Jepma (PROBASE Project Manager); e-mail: <jiq@northsea.nl>
Mr Johannes Rosen, IIP at the University of Karlsruhe, Germany, ph (+49 (0)721) / 608-4690; e-mail: <johannes.rosen@wiwi.uni-karlsruhe.de>

Global Reporting Initiative

Description: The Global Reporting Initiative (GRI) is a multi-stakeholder process and independent institution whose mission is to develop and disseminate globally applicable Sustainability Reporting Guidelines.

Methodology: For the reporting of indirect emissions from electricity and heat use, the Global Reporting Initiative refers to the World Resources Institute's Greenhouse Gas Protocol (see 1.1.6).

Relevance: Just as the UNCTAD Manual, the Global Reporting Initiative is very relevant to corporate environmental reporting.

Discussion: The WRI's Protocol for corporate reporting is not relevant for the CEC work.
Documentation: Sustainable Reporting Guidelines. Global Reporting Initiative, Boston, MA, 2002

Contact: GRI, Amsterdam, Netherlands, Tel: (+31 (0)20) 531 00 00; <guidelines@globalreporting.org>

WRI GHG Reporting Standard

Description: The World Business Council for Sustainable Development (WBCSD) and World Resources Institute (WRI) have created two standards for GHG emission quantification and reporting: one is used worldwide by businesses to report and set targets for their greenhouse gas (GHG) emissions, and the other (currently only available as a conceptual draft) targets project-based GHG emissions, including greenfield renewable energy facilities. The standards are meant to increase the standardization and harmonization of GHG accounting and reporting frameworks worldwide, and especially to allow multinationals to report on their emissions using one common format.

Methodology: The *GHG Protocol Corporate Standard* provides methodologies for the corporate sector and is mainly tailored to electricity consumers, including in-house energy efficiency improvements. It recommends the use of average emission factors - either based on average emissions from the operations of the electricity provider, or based on regional emission factors (e.g., US Power Pools). As no standardized methodology for the quantification of offsets exists, corporate emissions and offsets purchased must be reported separately, rather than combined into one single number. However, the Reporting Standard encourages the use of renewable energy certificates to offset indirect emissions from electricity use. For project-based emission displacement calculations, it refers to the forthcoming *GHG Protocol Project Quantification Standard*, which details quantification methodologies and baselines for offset projects.

The draft *Project Quantification Standard* is not completed yet. The current road test draft does not reflect current developments, which according to WRI will lead to a dual methodology allowing for the use of either a project-specific or a performance standard methodology. For the CEC working group, the initial (outdated) road test draft is considered here, which allows for three different methodologies to quantify project-based emission reductions: a project-specific methodology, a multi-project baseline, and a retrofit procedure. The multi-project baseline is largely based on the methodology developed by the Lawrence Berkeley National Laboratory (see below). The retrofit baseline procedure applies to retrofit projects, such as upgrades to more efficient equipment, or from single-cycle to combined cycle plants. It uses the historical emission of the pre-retrofit condition as the baseline scenario for the remaining life of the equipment being replaced, or crediting period, whichever is shorter. After the crediting period, a project specific or multi-project baseline must be applied. It will only rarely be applied to renewable energy projects (such as upgrades from heat use in the pulp and paper sector to CHP).

In general, the Standard recommends using the methodology required by any program that the project is proposed under. If there is no such methodology, the project developer chooses one of the three baseline methodologies mentioned above.

a) Specific Baseline (project specific)
The specific baseline allows for the selection of recent plants (last 5-7 years) or plants under construction, i.e., the build margin, as the baseline. The technology (and hence emissions) representative of the build margin is determined based on a selection of possible alternatives, choosing the most conservative one (i.e., the one with the lowest emissions, such as combined cycle natural gas), or based on an Investment Ranking Test, which determines which technology has the highest return on investment. It is also possible to use the system average for base and peak load power plants if it is known how much base and peak load a renewable energy plant will displace (for example, this may be specified in the power purchasing agreement).

b) Multi-Project Baseline
The multi-project baseline provides a choice between a Non-Firm and Firm Power Classification on the one hand, and a Combined Margin approach on the other. There is no preference for one methodology over the other.

Table A2 Project Types and Corresponding Baseline Methodologies under the Multi-Project Baseline Approach

Project power classification[a]	Non-firm (intermittent power sources)	Firm baseload	Firm load-following
Project types included	Solar[b], wind, small energy efficiency projects	Large coal, large hydro, or large combined cycle gas	Gas turbine, small hydro
Emissions path affected	Operating margin	Baseload build margin	Load-following build margin
Performance standards used	Weighted average of all existing load-following plants	Percentile of recently built baseload plants	Percentile of recently built load-following plants
Plants used to construct the performance standard	All existing load-following plants	Recently built baseload plants	Recently built load-following plants

a: This classification is only meant to be a guide, and developers should assess the characteristics of the grid, project and candidates when making the final classification of projects and baseline candidates.
b: solar may sometimes generate electricity for a certain number of hours per day, and be reliably generated in certain areas. Where this occurs, classify solar as firm load-following.

<u>Non-Firm and Firm Power Classification</u>

This methodology uses the average emissions of load-following plants, the base load build margin or the peak load build margin. The project is first classified as a base or peak load plant (or a combination of both), which influences the choice of possible baselines. The baseline is the weighted average of base or peak load plants. It is recommended to increase the stringency level above this average, a 25th percentile level being the default level.

Non-firm (e.g., wind, solar, probably run-of-river): modified system average = average of all load-following plants, without known base load plants

Firm base load (this would probably include biomass and geothermal): build margin = capacity additions of firm power plants (coal, large hydro, large CCNG) over past 5-7 years

Firm load-following (small hydro with storage): build margin = capacity additions of firm load-following power plants (gas turbine, small hydro) over past 5-7 years

Note: The draft Protocol does not specify clearly how firm renewable power sources, such as geothermal or biomass, should be classified.

<u>Combined Margin</u>

The average of the build and operating margins is used to evaluate emissions displaced by the project during the first five years, and after this only build margin is used. This methodology classifies plants as base or peak load plants based on their capacity factor. By default, plants with a capacity factor higher than 70 percent are base load. To calculate the operating margin, a new plant is assumed to displace power from coal, oil, natural gas, and high-cost biomass. In grids that consist predominantly of large hydro, 50 percent of this resource is also displaced. Existing renewable energy projects, including low-cost biomass, and nuclear are not displaced.

Operating margin: Average of all plants, without known base load plants

Build margin: recent capacity additions of all plants (both base and peak load)

Combined margin: First five years = (operating margin + build margin)/2; after that: build margin only

This methodology distinguishes between high and low-cost biomass. Low-cost biomass is defined as plants using biomass residues, such as bagasse from sugar refineries or pulp and paper residues. High-cost biomass is defined as plants that use dedicated energy crops or have high feedstock transportation costs.

Relevance: The corporate standard, first launched in 2001, has become the most widely used global standard for corporate accounting of greenhouse gas emissions. It was developed by over 500 experts from businesses, NGOs, and governments. It has been adopted by over 150 companies, including industry associations representing pulp and paper, aluminum, and cement, and enjoys the support of NGOs and governments alike. Numerous climate initiatives, including reduction programs, trading schemes, environmental standards, and registries have based their measurement and reporting guidelines on the GHG Protocol. This includes the US EPA Climate Leaders Initiative, Global Reporting Initiative, the WWF Climate Savers Program, California Climate Action Registry, World Economic Forum Global GHG Register, the UK Trading Scheme, the Chicago Climate Exchange, and the monitoring protocols of the EU Trading Scheme. It is also contributing to other accounting efforts, such as the forthcoming ISO standard on GHG accounting (see 1.2.4), which has signaled its intent to be compatible with GHG Protocol. It was recently adopted by Mexico.

Work on the project-based standard is still ongoing. WRI formed an Electricity Sector Project Accounting Sub-Group, which will come together in the fall of 2004 to continue working on methodologies for renewable energy and energy efficiency projects. WRI is expanding the circle to include more experts, and substantial changes to the proposed methodology may still occur. The working group hopes to have a final draft of the standard by mid-2005. The Protocol was designed to be program-neutral, i.e., it allows for program-specific quantification methods to be used. It makes reference to the CDM process, and the combined margin approach in the road test draft is largely the same as the CDM Consolidated Methodology. It is not possible to evaluate the WRI work's suitability to the CEC working group task until a better understanding of the forthcoming WRI methodology can be gained.

Discussion: The "specific baseline" is a simple method of calculating emission reductions, based on the average of all newly built plants. It does not consider effects on the operating margin, and is most likely too simple to be accepted for North America. Likewise, the multi-project baseline does only take either the operating or the build margin into account. This leads to inaccuracies, as all renewable energy projects, including intermittent technologies, would have impacts on both margins. Also, splitting plants into base and peak load plants is not always straightforward, as some plants fulfill both roles. The issue of treating low and high cost biomass differently would need to be discussed within the CEC working group.

Documentation: The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard, Revised Edition.

The Greenhouse Gas Protocol: Project Quantification Standard—Road Test Draft. WRI and WBCSD, September 2003

Web site: http://www.ghgprotocol.org

Contacts: Derik Broekoff, Senior Associate, World Resources Institute, Climate Energy & Pollution Program, Tel: (202) 729-7628, e-mail: <dbroekhoff@wri.org>
Florence Daviet, Research Analyst, Climate Energy & Pollution Program, World Resources Institute, (202) 729-7822, <fdaviet@wri.org>

ISO Standard

Description: Within the ISO 14000 series, the International Standards Organisation is developing the ISO 14064 Standard for GHG Accounting. Its release is planned for late 2005. The standard will have three parts: Part I: Quantification, Monitoring for organizations; Part II: GHG Projects; Part III: Verification.

Methodology: The Standard is split into a part relevant to corporate GHG accounting and another one for project-based offsets. For corporations, the Standard does not specify a methodology to be used to quantify emission reductions. It requires that "the organization shall select a quantification methodology or methodologies that will minimize uncertainty and yield accurate and reproducible results for their GHG sources, GHG sinks and types of GHGs." **Part 1** distinguishes GHG projects and targeted activities. Project emission reductions need to be assessed against a counterfactual baseline, whereas targeted action is quantified by comparing actual emissions before and after implementation of the measure, for example. For project-related emission reductions (both organization-internal and external projects), Part 1 of the Standard refers to the guidance provided in Part 2.

Part 2 does also not specify a methodology, but requires that "the project proponent shall select and justify the baseline scenario that represents the most appropriate and best estimate of the GHG emissions and removals that would have occurred in the absence of the project." The Appendix of the Standard refers to the Kyoto baseline specifications, and leaves space for the later inclusion of "Other Good Practice" baselines in an informative box, which is not part of the mandatory requirements in the Standard. The Standard requires a recalculation of projected emission reductions at the end of the project period.

Relevance: Part 1 of the ISO Standard tries to provide a format and methodology for corporate GHG accounting, to make the reporting more comparable. Part 2 also provides a format (but no methodology) for calculating emission reductions, although the Standard is meant to be used in combination with GHG programs and regimes, which may specify detailed instructions on calculation methodologies.

The Standard was written to allow integration with related initiatives, such as the WRI GHG Protocol. Much emphasis was laid on compatibility with the Kyoto Flexible Mechanisms, especially the CDM.

The Standard requires detailed documentation to quantify emission reductions, which may make it unattractive for the quantification of GHG offsets for RECS in North America.

Documentation: Greenhouse gases—Part 1: Specification for the Quantification, Monitoring and Reporting of Organization Emissions and Removals. International Standards Organisation, TC207, November 10, 2003

Greenhouse gases—Part 2: Specification for the Quantification, Monitoring and Reporting of Project Emissions and Removals. International Standards Organisation, TC207, November 10, 2003

Web site: http://www.pacinst.org/inni/Climate.htm

Contact: Kevin Boehmer, Canadian Standards Association, Tel: (416) 747-2231; e-mail: <kevin.boehmer@csa.ca>
Derryl Neat, CSA Business Management and Sustainability, Secretary of ISO Climate Change Mirror Committee, Tel: (416) 747-2539; e-mail: <derryl.neat@csa.ca>.

IEEE GHG Standard P1595

Description: The Institute of Electrical and Electronics Engineers (IEEE) Power Engineering Society (IEEE-PES) and the IEEE-Standards Association (IEEE-SA) have initiated Standards project P1595 in August 2001. The goal of Project P1595 is to develop a set of international standards for the quantification of GHG emission credits from certifiable projects in the electricity sector. This is a multi-year multi-Part standards project and the first Part will give priority to Renewables and Energy Efficiency projects.

The proposed concept is a set of performance standards which will set minimum criteria for the ownership, quality, certainty and accuracy of GHG emission credits independent of the source or technology of the GHG reduction or removal. These standards will be globally applicable and will simplify the cost effective evaluation of project GHG credits, thus facilitating the trading and retirement of such credits in national and international markets. A draft standard is available to working group members for discussion, but further work depends on funding.

Methodology: The draft standard does not contain specifics on a methodology, but only principles that are to underlie the methodology to be developed for the final standard. The IEEE standard may use the work currently being undertaken by the WRI/WBCSD initiative for a GHG Project Protocol and turn it into a formal standard. IEEE would not only turn the WRI work into a formal international standard, but would also maintain the standard through technical reviews scheduled in five-year intervals.

Relevance: The emergence of an IEEE standard on calculation methods can be seen as very relevant to the CEC working group's target, as it is likely to be adopted by many market participants—especially if it is based on the WRI Protocol, which is backed by a team of international experts. IEEE is working with European, as well as North American representatives, and the process is open to participants from any other countries. IEEE works with the International Electrical Commission, which is the equivalent of ISO for the electricity sector (ISO develops process standards, whereas IEC develops performance standards).

Discussion: The CEC may want to join and influence this standardization work. Once the working group has decided where to go with a North American methodology, influencing the WRI/IEEE work would be a logical next step.

Documentation: Preliminary standard document IEEE-P1595-D0.1 (only available to IEEE members)

Web site: http://grouper.ieee.org/groups/1595/

Contact: Jim McConnach, chair of IEEE Climate Change Working Group; <jsmcconnach@ieee.org>, Tel: (705) 645-5524

OECD/IEA

Description: The International Energy Agency and the OECD commissioned the Tellus Institute to develop a methodology for submission to the CDM Executive Board in order to arrive at a standardized methodology for electricity sector projects.

Methodology: According to the Tellus Institute, no single methodology can suit all the potential diversity of CDM projects in the electricity sector, which span a wide range of scales, fuels, and technologies and will take place in a varied set of electric sector contexts, both on and off the grid. This diversity calls for a range of baseline approaches. Tellus proposes a three-category framework for the different projects, with baseline and additionality methods specific to each, in order to balance the objectives of low transaction costs and environmental accuracy. Small–scale projects are allowed to use a less complicated methodology than lager-scale projects. Otherwise, Tellus recommends the combined margin approach, combining both build and operating margin:

Displaced emissions (1st crediting period) =
[Operating margin (year 1) + Build margin (last 20% built)]/2

For subsequent crediting periods, only the build margin baseline is used to calculate emission reductions based on new construction during the years 1-7:

Displaced emissions (2nd crediting period) = Build margin (first 7 years)

Displaced emissions (3rd crediting period) = Build margin (year 8 to 15)

The build margin baseline should generally reflect all power plant types being added to a system. It is recommended that this be calculated using the generation-weighted average emissions rate of the most recent 20 percent of plants built (on a generation basis), or the five most recent plants, whichever is greater.

Operating margin effects may predominate in the early years after CDM project implementation, before build margin effects take hold. The operating margin is not calculated using a dispatch model, but the weighted average of all resources *except* zero fuel-cost/must-run facilities.

For retrofit and fuel switch projects, it is recommended that the emission rate of the existing facility may be a valid baseline up to the amount of generation that the existing facility produces. For power generation beyond this amount, the combined margin baseline methodology should apply.

A combined-margin approach may not be sufficient for calculating emission baselines in cases where project proponents can clearly demonstrate that only one specific plant or plant type is being displaced by a "Category III" project, e.g., higher-efficiency fossil plants proposed to replace a lower-efficiency one at the same site, or biomass co-firing displacing coal. In such situations, *minimum performance parameters* (e.g., for efficiency and load factors) should be established to ensure that the baseline is not based on outdated or inefficient technology assumptions. Very large renewable energy projects are also allowed to use a baseline scenario (clearly defined technology that is assumed to be displaced) instead of the combined margin approach.

The default regional integration level for standardized electricity baselines should be the country level. However, countries can define separate sub-national grids or combine with other countries, based on actual power system management practices and transmission availability. It is recommended that project boundaries (i.e., which GHG emissions and sources associated with a project should be included in the emission baselines) for power generation projects be based on direct onsite emissions. Demand-side efficiency and distributed generation projects should be credited for avoided transmission and distribution (T&D) losses, using average grid area losses (and excluding "non-technical losses"), or national average losses where grid-specific loss data are unavailable. T&D would not be taken into account for the other types of electricity projects, as they are likely to not have any impact on T&D losses.

Relevance: The methodology was prepared by the IEA Secretariat at the request of the Annex I Expert Group on the United Nations Framework Convention on Climate Change. The Annex I Expert Group oversees development of analytical papers for the purpose of providing useful and timely input to the climate change negotiations. It is meant for the CDM, but also for any other emissions trading program. The CDM Executive Board has largely taken over this methodology for its standardized baseline procedures (see above).

Discussion: See section on the Kyoto Protocol's Clean Development Mechanism (above).

Documentation: Road-Testing Baselines for Greenhouse Gas Mitigation Projects in the Electric Power Sector—Information Paper. COM/ENV/EPOC/IEA/SLT(2002)6, Organisation for Economic Co-operation and Development, International Energy Agency, Paris 2002

Web site: <http://www.tellus.org>

Contact: Michael Lazarus, Tellus Institute, Tel: (206) 985-8124;
e-mail: <**mlaz@tellus.org**>

National Initiatives

United States

SO_2, NO_x

Under the US Acid Rain Program, a cap-and-trade system was set up which allowed for the use of renewable energy as a means of creating allowances. Between 1992 and 1999, the EPA established a Conservation and Renewable Energy Reserve (CRER) of 300,000 SO_2 allowances, set aside from the emissions cap imposed on power plants. Of these, 60,000 allowances were set aside as a minimum for renewables. One allowance, equivalent to one tonne of SO_2, would be produced by 500 MWh of renewable electricity. At an output-based rate of about 11 lbs SO_2/MWh, a conventional coal power plant would emit 2.75 tonnes per 500 MWh. The low rate of allowances granted to one MWh of renewable generation resulted in only 6,700 allowances being allocated to renewables. Other means to reduce sulfur emissions from coal proved to be more cost effective.

Under the Acid Rain Program, the EPA also introduced NO_x allowance trading. A State Implementation Call leaves some of the details of allocation of allowances to renewable energy projects to the states. However, the quantification methodology is fixed and is based on an emission factor of 1.5 lb NO_x per MWh. States have created allowance set-asides for renewables, generally 3–5 percent of the total allowance budget for each trading period (May to September). Only few renewable energy generators have made use of these provisions. Applying for the allowances is often cumbersome, and the economic benefits are fairly small (less than half a cent per kWh).

NREL Methodology for NO_x State Implementation Plan Call

Description: The National Renewable Energy Laboratory took several approaches to quantifying emission reductions of a 9 GWh energy efficiency project (retrofitting municipal buildings). The EPA and Department of Energy provided funding for this project, which tries to compare results of three different calculation methodologies. This work applies to nitrogen oxides only, but could easily be expanded to other emissions.

Methodology: Three approaches were applied to an energy efficiency project amounting to 9 GWh saved over one year.

a) Marginal dispatch model developed by Art Diem, EPA. This method estimates the percentage contribution of each relevant Power Control Area (PCA) to the electricity consumption of the region where the demand reductions occur. These estimates are developed using data on the power flows between all the PCAs, in both directions. Second, this method develops estimates for the share of generation from each power plant based on the total power generated in that PCA. Combining the two stages yields weighted percentages for the power plants within all contributing PCAs. This modeling approach specifically considers those plants that are used to estimate the fraction of generation reductions occurring at each power plant.
b) LSU Center for Energy Studies Modeling Approach. The model economically dispatches generating facilities on an hour-to-hour basis. Under an optimal economic dispatch, generators are essentially ranked, or “stacked” based upon their costs, with the lowest cost unit being utilized first, and the highest cost unit being utilized last. A base case and a project case are then modelled, and the difference between the two represents the emissions displaced.
c) EGRID Subset: This database provides emission factors based on power plant units, and integrates those to a national emission factor. The data resolution can be increased so that only specific plants relevant to the project area are considered. This is at a sub-Power Control Area level, i.e., the local plants only.

The results of the comparison was 3.37 lbs/MWh for a), 2.85 lbs/MWh for b) and 1.95 lbs/MWh for c) when the local plants are used (3.38 if the NERC sub-region is used). The team recommends using the NERC Sub-Region (grid average) as the methodology to calculate emission reductions of small energy efficiency projects up to 500 MWh/day. This would correspond to a wind plant of a capacity of 70 MW (30 percent capacity factor). Above this level, the team recommends using the dispatch methodologies a) or b).

Relevance: The methodology is submitted to the EPA for use to quantify NO_x emission credits within the State Implementation Plan framework. The simple methodology is recommended because of the cost implications for small project if more intricate methodologies were used. The same model could be used for other emissions, such as SO_2 or CO_2, should the EPA become active in the GHG field in the future.

Discussion: The approach confirms the findings of this report, i.e., that a dispatch model should be used, rather than a simplified methodology, which is only recommended for smaller projects. A comparison of the models suggested with other models would be helpful to decide which one should be recommended by the CEC working group.

Documentation: Chambers, Adam: Comparison of Different Methods for Developing NO_x Emission Factors for Assessing EE Projects in Shreveport, Louisiana. National Renewable Energy Laboratory, Washington, DC, September 2004

Web site: not available

Contact: Adam S. Chambers, Project Leader, National Renewable Energy Laboratory, Washington, DC, Tel: (202) 646-5051,
e-mail: <Adam_chambers@nrel.gov>

RGGI

Description: The Regional Greenhouse Gas Initiative is a process involving several New England states and some Eastern Canadian provinces (as observers) and aims to create a regional common GHG emission policy. The approach will most probably involve a cap-and-trade program, which is likely to allow for the use of carbon offsets, such as from renewable energy plants.

Methodology: There is no methodology yet, but WRI recommended to RGGI that the emerging WRI Project Standard should be used. RGGI is also using ICF's IPM model to assess the impacts of a CO_2 emissions cap.

Relevance: As RGGI may become the most important GHG trading regime next to the Canadian trading system and voluntary approaches, such as the Chicago Climate Exchange, this initiative will have major impacts on carbon trading in North America. Seen that RGGI uses the ICF model for modeling the cap, it is possible that the same model will later be selected to calculate GHG emissions from renewable energy operations as well.

Discussion: See section 1.2.3.

Documentation: not available yet.

Web site: <http://www.rggi.org/>

Contact: James Brooks, State of Maine, Tel: (207) 287-7044;
e-mail: <James.p.brooks@maine.gov>

Chicago Climate Exchange

No offsets or allowances can be gained through external renewable energy projects under the Climate Exchange rules. However, distributed (on-site) generation can be used to reduce electricity purchases from the power grid, and if company targets are exceeded, allowances for the portion of reduced electricity demand above the set target will be issued. These allowances are calculated based on a national grid average emission factor.

Lawrence Berkeley National Laboratory (MAGPWR)

Description: Lawrence Berkeley National Laboratory (LBNL) developed the MAGPWR (Marginal Avoided GHG – Power) model—a standardized method for establishing a multi-project baseline for a power system. The method provides an approximation of the generating sources that are expected to operate on the margin in the future for a given electricity system. It is most suitable for small-scale electricity generation and electricity efficiency improvement projects. It allows estimation of one or more carbon emissions factors that represent the emissions avoided by projects, striking a balance between simplicity of use and the desire for accuracy in granting carbon credits. It requires a relatively small amount of data, and is easily understood by interested parties. It could be used by a national energy agency or an entity with specific responsibility for CDM or JI projects.

Methodology: The method is primarily intended for small-to-medium size projects that affect operation at the margin. However, the basic approach could also be used to model substitution of a large project power plant for a planned power plant that would otherwise be part of the system.

Each power source (e.g., coal, natural gas) is seen as if it were a single homogenous unit. There is no attempt to depict the system operation with respect to dispatch of individual units. The emission factor used for each type of generation would normally be the average value, unless there is good reason to use a different value. Once a Load Demand Curve is available for a given period, deriving a factor for avoided carbon emissions is straightforward. If only one source is marginal for the entire period, the appropriate factor is simply the emissions factor for that source. If two or more sources are marginal, the factor is the average of the respective emission factors for each source, weighted by the percentage of hours in the period for which each source is marginal. The farther in the future one projects, however, the more difficult it is to estimate the system's operation. The best approach would be to use the method to derive emission factors on an annual basis.

The emission factors for an electricity system could be of two types. A short-run estimate (one year) could be used for calculations of the amount of carbon credits projects could claim for a given year. For example, the host country government could announce emission factors at the beginning of each year based on current projections of the system's operation for that year. That emission factor would then be applied to the verified electricity generation or demand reduction accomplished by projects in that year. A long-run estimate (10 to 15 years) could be used for estimating carbon emissions that may be avoided by projects during their lifetime. This would represent an official “best guess”—based on official plans, if possible—that could be used for projecting potential revenue from carbon credits.

Relevance: The model is cheaper and more transparent than others, such as the ICF model, and uses load profiles for each technology. This allows to distinguish between the actual impacts of various renewable energy technologies, such as wind and solar, with different profiles.

Discussion: This model seems to be a good tool to calculate the operating margin. It does treat different technologies differently according to load profiles, and models future operating margins. It is not designed, however, to calculate build margins. So far, the model has been developed for California, Wisconsin, and Brazil.

Documentation: Meyers, S. et al.: Estimating Carbon Emissions Avoided by Electricity Generation and Efficiency Projects: A Standardized Method (MAGPWR). Energy Analysis Department, Environmental Energy Technologies Division, Lawrence Berkeley National Laboratory, Berkeley, CA 94720 USA, July 2000

Web site: eetd.lbl.gov/EA/EMS/reports/46063.pdf

Contact: Scott Murtishaw, Lawrence Berkeley Labs, Tel: (510) 486-7553,
e-mail: <SGMurtishaw@lbl.gov>

Lawrence Berkeley National Laboratory (MBASE)

Description: One approach to estimating average and marginal emissions rates for a grid is to use relatively sophisticated generation planning models, e.g., Elfin or WASP, that simulate future grid operation in order to meet a forecasted hourly load. As an alternative to these often costly and opaque models, LBNL has developed a relatively simple spreadsheet, MBase, using weighted averages to estimate build and operating margins in addition to the MAGPWR load-duration curve spreadsheet used for calculating operating marginal emissions rates. MBase was evaluated in case studies of grids in India, South Africa, and Guatemala. It is suggested for use as a multi-project baseline in the CDM, in government programs, or for multiple project applications.

Methodology: The method used in MBase offers a simple and transparent method for calculating both build and operating marginal emissions rates as the weighted averages of various categories of plants. Using the operating information on existing and/or planned units serving the grid allows MBase to generate several types of benchmarks. Build margins are calculated as the average emissions rates of recently built plants or those under construction, and the operating margin is estimated as the weighted average emissions of all existing load following plants serving the grid.

The essential data required for estimating multi-project emissions rates (MPERs), are the fuel input (in GJ per year) and electrical output (in TWh/year) of all load-following plants and all recently built or planned baseload plants. Combining this information with the carbon content (kg C/GJ) of the fuel, one can calculate each plant's emissions rates in kg C/kWh.

Non-firm power projects, such as solar, wind, run-of-river hydro or energy efficiency projects, are assumed to mostly displace power from existing load following plants. Thus, utility planners must still plan for new capacity despite additions of non-firm generating resources, and the build margin is not affected. Firm power projects, such as biomass and geothermal, are seen as having effects primarily on build margins. In cases where projects have both firm and non-firm operating characteristics, or are seen as displacing both at the operating and build margins, capacity may need to be split into firm and non-firm portions so that a combination of both margins are offset. Output up to a certain level would be compared to firm capacity baseline rates while additional generation would receive reduction credits based on the displaced emissions rate for non-firm power.

Table A3 Project Types and Suggested Baselines

Project Generation Profile	Nonfirm (intermittent or unpredictable power sources)	Firm Baseload	Firm Load-Following
Project Examples	Solar, wind, small efficiency	Large coal, hydro, or combined cycle gas plant	Gas turbine, small hydro
MPER Types	Operating Margin	Baseload Build Margin	Load-Following Build Margin
Plants Used For MPERs	All Existing Load-Following Plants	Recently Built Baseload Plants	Recently Built Load-Following Plants

MPER: Multi-project Emission Rate#

It is recommended that the build margin be determined by averaging emission factors from plants built over the past five years, and not be based on projected plant additions, since projections of additional capacity may prove unreliable. A near-future build margin determined based on planned additions may be used if the above is not feasible, or not reflective enough of expected changes.

The build margins can be further refined using a stringency criterion based on either the weighted average, 25 or 10 percentiles (average of lowest-emission plants representing 25 or 10 percent of annual generation), or using the "best plant" as the baseline. This is done for each fuel type separately, and the numbers are then weighted and summed (assuming a constant share of electricity generation between the fuel types) so that the stringency results are not determined by fuel type. Applying these stringency criteria is not relevant to the calculation of operating margins.

Relevance: LBNL has done similar work for the EPA in the past. Their work has also contributed to the WRI process to create the project Protocol (see above).

Discussion: The methodology provides several options on calculation details, which increases complexity and makes the comparison and coherence of results a challenge. One advantage of the model is that it is simple to use and does not require very refined data. More accurate results would require users to have some sense of the load profiles of both proposed projects and the existing plants serving the grid. The model allows for a combined margin approach, similar to the CDM consolidated methodology, by weighting capacity between build and operating margins. While the different treatment of technologies based on load curves is not possible, an approximation could be made by developing different data sets to be used for different seasons to reflect variability across the year.

Documentation: Sathaye, Jayant et al.: Multi-project Baselines for Evaluation of Electric Power Projects. LBNL-51917, Lawrence Berkeley National Laboratory, Berkeley, CA

Web site: http://eetd.lbl.gov/ea/ies/MBase/index.html

Contact: Scott Murtishaw, Lawrence Berkeley Labs, Tel: (510) 486-7553, e-mail: <SGMurtishaw@lbl.gov>

Oregon Climate Trust/EPA

Description: The Environmental Protection Agency had a consultant determine average marginal emission factors for all US states. They were grouped into ten regions.

Methodology: The Cadmus Group, Inc. used the average of all marginal units to calculate emission factors for the United States.

Table A4 Average Marginal Emission Factors

EPA Region	States Within Region	lbs. CO_2/kWh
Region 1	MA, CT, ME, NH, RI, VT	1.726
Region 2	NY, NJ	1.679
Region 3	PA, VA, MD, WV, DC, DE	2.096
Region 4	FL, NC, GA, TN, AL, SC, KY, MS	2.215
Region 5	OH, IL, MI, IN, WI, MN	1.988
Region 6	TX, LA, OK, AR, NM	1.186
Region 7	MO, IA, KS, NE	1.404
Region 8	CO, UT, MT, WY, ND, SD	1.244
Region 9	CA, AZ, NV	1.240
Region 10	WA, OR, ID	1.202
National		1.640

Source: The Cadmus Group, Inc., *Regional Electricity Emission Factors Final Report*, The Cadmus Group, Inc., 1998, Exhibit 6.

Relevance: While the Climate Trust is still using this 1998 data, the current trend in the United States is toward more sophisticated calculation methods.

Discussion: The CEC should strive to provide similar factors for North America, although they should be calculated for each technology and based on a more sophisticated methodology.

Documentation: Regional Electricity Factors Final Report, US Environmental Protection Agency, Atmospheric Pollution Prevention Division (APPD), 16 November 1998, contract no. 68-W6-0050.

Web site: <http://www.climatetrust.org/2001.html>

Contact: Mike Burnett, Tel: (503) 238-1915; e-mail: <mburnett@climatetrust.org>

Power Pools

Description: Several US Power Pools are using proprietary software to model future generation needs and emissions from plants that will be built to replace retired plants and additional capacity requirements. For example, ISO New England issues an annual marginal emissions report for the New England Power Pool's Environmental Planning

Committee. The methodology is intended to quantify emission reductions from energy efficiency projects and uses the Interregional Electric Market Model (IRREM) to determine which plants would increase their output if energy savings measures would not have been implemented, or could conversely determine how emissions have been reduced as more renewable energy comes online. The methodology does not allow for changes in electricity imports due to renewables, as those are left constant, suggesting only plants inside the pool are affected by the addition of renewable energy projects. It determines the marginal emission rate ex-post, i.e., for the previous year of operations, and is adjusted to reflect actual plant outputs within 25 percent or less of the actual output. The model is based on the assumed cost of generation from each unit, not actual bidding prices. It does not model transmission constraints, but captures annual plant capacity factors from data gained from the previous year. It also does not capture hourly load profiles of new projects, but assumed an even amount of generation throughout the day, based on annual load profiles of the existing generation mix.

The Northwest Power and Conservation Council uses an hourly dispatch electricity price forecasting model, which can also be used to estimate marginal emission rates and the influence of renewable energy projects. The basis for the methodology is the AURORA^{xmp}™ Electric Market Model from EPIS Inc. <www.epis.com>, which uses a bottom-up approach that contains data for each plant and incorporates transmission constraints and future pricing. The model results are highly sensitive to inputs in terms of the Production Tax Credit, natural gas prices and CO_2 emission allowance prices, for example. Results from initial runs were sometimes counter-intuitive, indicating the model needs some adjusting before acceptable results can be delivered. AURORA exists in both Canada and the United States and could therefore be easily tested by the CEC working group.

A number of other such models exist, which should be examined for their suitability, accuracy and cost.

Relevance: Methodologies already being used by Power Pools may be adopted by the CEC working group to use them in all three countries concerned. They are already tested in other fields, such as pricing or demand forecasts, and can be further tested for their suitability to calculate marginal emission rates.

Contact: IRREM - Jim Platts, ISO New England
AURORA - Jeff King, Northwest Power and Conservation Council, Portland, Oregon

Energy 2020

Description: The ENERGY 2020 model is an integrated multi-region energy model that provides complete and detailed, all-fuel demand and supply sector simulations. It portrays the interaction of market competitors in a realistic, as opposed to an idealized, fashion, including transmission-system market-dynamics. It focuses on the imperfections of the market, including market gaming. Pollution emissions and costs, including allowance and trading, are endogenously determined, thereby, allowing assessment of environmental business-risks.

Methodology: The model dispatches plants according to the specified rules whether they are optimal or heuristic and recognizes transmission constraints as well as the associated costs. The supply portion model includes endogenous detailed electric supply simulation of capacity expansion/construction, rates/prices, financial/accounting, load shape variation due to weather, and changes in regulation. Different regions, such as power pools, can be set as the level of integration. The ENERGY 2020 model includes pollution accounting for both energy (by fuel, end-use and sector) and non-energy (by economic activity) for SO_2, NO_2, N_2O, CO, CO_2, CH_4, TSP, VOC, CF_4, C_2F_6, SF_6, and HFC. Pollution is not determined directly by coefficients but rather by the accumulation of capital investments that result in pollution emission with usage. National and international Allowance trading is also included. Plant dispatch can consider emission restrictions.

Relevance: Energy 2020 is available for the United States and Canada. The model is being used by the US EPA and also by the Canadian government to model policy impacts for its Climate Change Plan.

Discussion: The model is very sophisticated and can be used to forecast future emission reduction effects from renewable energy. It should be considered together with other models as an option to be used by Canada, Mexico and the United States to calculate emission reductions from on-grid renewables.

Documentation: see web site.

Web site: www.energy2020.com

Contact: Jeff Amlin, President, Systematic Solutions, Inc., Fairborn, Ohio, Tel: (937) 878-8603, e-mail: <Jeff_Amlin@ENERGY2020.com>.

Canada

Canada’s Offset System

Description: Canada decided to grant GHG offset credits to on-grid renewable energy projects in the context of its national emission allowance/offset trading system. Offsets are allowed to be used by the “Large Final Emitters” sector in Canada to reach set performance targets relating to GHG emissions.

Methodology: Work on the details of Canada’s emissions trading system under the Kyoto protocol is till in progress. A decision about the inclusion of certain types of offsets, including renewables, is still outstanding. Until such decisions have been made, and an allocation methodology been selected, there are several options that may be implemented:

a) Equal Allocation: renewable energy projects would be allocated 20 Mt of permits rated at 0.454 t/MWh. This number is derived from a total allocation of 110 Mt, which corresponds to the BAU forecast for 2010 from all thermal power sources, less 15 percent.

b) Set-Aside: 10 Mt of CO_2 emissions are allocated to the 45 TWh of new clean energy in the federal forecast, resulting in an allocation rate of 0.22 t/MWh.

c) Offset System: Suggestions made include determining offsets for large-scale projects (such as large hydro) on a case-by-case basis, and setting a standard emission factor, such as a CCGT equivalent, for smaller projects.

Note that the allocations of permits to renewables are arbitrary and may change when a final decision is made.

Relevance: Canada's Offset System methodology is likely to strongly affect the Canadian renewable energy sector.

Discussion: A simplified methodology, such as using CCGT emissions as the standard emission reduction parameter, could create a mismatch between the national inventory and actual emission reductions. It also does not reflect regional differences in the types of power sources displaced by renewable energy projects.

Documentation: Treatment of Clean Energy Investments under the Large Final Emitters Policy, 12 March 2004.

Web site: <http://www.climatechange.gc.ca/english/offsets/>
<http://www.nrcan-rncan.gc.ca/lfeg-ggef/English/lfeg_en.htm>

Contact: Judith Hull, Environment Canada, Tel: (819) 994-6128; <Judith.Hull@ec.gc.ca>

SMART – TEAM protocol for GHG reporting

Description: Technology Early Action Measures' (TEAM) mission is to invest in technology demonstration and late stage development in support of early action to reduce GHG emissions (or enhance GHG removals), nationally and internationally, while sustaining economic and social development. Within TEAM's Business Plan and Management Framework, TEAM is committed to report the technical performance and GHG mitigation potential of TEAM funded projects. It uses the System of Measurement And Reporting for Technologies (SMART) Protocol to provide the basis, in terms of process, general requirements and guidance, to develop and/or evaluate the project proponent's processes and documentation to substantiate the technology performance claim(s) and assess the GHG mitigation potential.

Methodology: The SMART Program refers to the GHG scheme under which a project is developed for specific guidance on calculation methodologies. In the absence of such methodologies, it recommends using guidance from the WRI GHG Protocol, or from the CDM Executive Board (both were discussed above).

Relevance: This Protocol is used in the area of quantifying environmental benefits of government programs in Canada.

Documentation: Requirements and Guidance for the System of Measurement and Reporting for Technologies (SMART) – January 2004 (see web site)

Web site: <http://www.climatechange.gc.ca/english/publications/team_smart/>

Contact: Thomas Baumann, Natural Resources Canada, Tel: (613) 943-5913 <Thomas.Baumann@nrcan-rncan.gc.ca>

PERRL

Description: The Pilot Emission Removals, Reductions and Learnings Initiative (PERRL) is a federal initiative under the government's Climate Change Action Plan. It is designed to provide Canadian companies, organizations and individuals with an economic incentive to take immediate action to reduce greenhouse gas emissions, i.e., before a mandatory trading program is put into place. As a pilot project, it is also intended to help both Canadian governments and private sector organizations learn about and better understand a number of important elements of emissions trading, a key policy measure which will be instrumental in helping Canada meet its climate change objectives. PERRL works through RFPs specifically defined for certain activities that can create offsets. The latest RFP in 2004 was for renewable energy projects.

Methodology: The PERRL methodology was not included in the CEC background paper. A presentation was made at the 2003 Washington workshop, but did not provide specifics on calculation methods. The quantification of offsets is based on a proprietary **dispatch model** developed by ICF Consulting.

ICF uses its Integrated Planning Model (IPM®) to determine unit level and capacity type dispatch order, which is used to develop emission factors. IPM® is a detailed engineering-economic capacity expansion and production costing model of the power sector that simultaneously accounts for conditions in the electric, fuel and environmental markets. IPM® determines the least-cost way to meet a system's electricity demand, provided by the user, while meeting a number of constraints over the time frame under study. It is a multi-region model that models the electric demand, generation and transmission within each region as well as the transmission grid that connects contiguous regions. In the United States, the regions are the 26 NERC sub-regions (excluding Hawaii). The model simulates total monthly generation on the margin for each province in Canada for the years 2004 to 2007.

The "on-margin" generation represents power from the last (most expensive) unit to dispatch in different segments of the day. The load duration curve can be tailored to capture periods of time in increments up to 8760 hours of the year. For example, if the model predicts that 40 percent of on-margin generation is coal, 30 percent gas, and 30 percent imports, the marginal emission intensity is calculated as [tonnes CO_2/MWh]= [0.4 X tonnes $C0_2/MWh_{coal}$] + [0.3 X tonnes $C0_2/MWh_{gas}$] + [0.3 X tonnes $C0_2/MWh_{imports}$]. The provincial emission factors calculated by the model for the year 2005 are given in Table A5.

The model predicts that landfill gas and wood and wood waste-powered generation is on the margin during the summer months in several provinces. Therefore, depending on the grid access policy for renewables, existing renewable resources may be displaced by newly added renewables.

Table A5: Monthly Displaced Emission Intensities [tonnes CO_2 / MWh] for 2005

	Province							
Month	**BC**	**AB**	**SK**	**MB**	**ON**	**PQ**	**NS**	**NB/PEI**
Jan.	0.41	0.44	1.53	1.02	0.00	0.04	0.51	0.81
Feb.	0.47	0.43	1.54	1.02	0.46	0.04	0.59	0.8
Mar.	0.41	0.47	1.46	1.02	0.98	0.00	0.29	0.75
Apr.	0.04	0.42	0.00	1.02	1.16	0.04	0.42	0.75
May	0.04	0.43	0	1.02	1.11	0.04	0.81	0.75
Jun	0.04	0.47	1.54	1.02	1.14	0.04	0.81	0.77
Jul	0.04	0.58	1.54	1.02	1.08	0.04	0.82	0.77
Aug	0.04	0.62	1.54	1.02	0.97	0.04	0.81	0.79
Sep	0.05	0.48	0.00	1.02	0.03	0.05	0.52	0.81
Oct.	0.05	0.43	1.54	1.02	1.05	0.04	0.51	0.81
Nov.	0.01	0.44	0.41	1.02	0.00	0.04	0.49	0.81
Dec.	0.3	0.45	0.41	0.00	0.00	0.00	0.51	0.81

Relevance: It is difficult to say which influence PERRL may have. So far, it seems that the Canadian Offset System will not take over the PERRL methodology. The RGGI process is using ICF's model to determine the impact of an emissions cap, and may select to use the same model to quantify emission reductions from renewables.

Discussion: The ICF model is one that the CEC should consider for its work. The monthly dispatch data fit well with the requirements for a North American Methodology.

Documentation: (see web site)

Web site: http://www.ec.gc.ca/PERRL/home_e.html

Contact: Robin James, PERRL, Environment Canada, Tel: (819) 953-4820; e-mail: <Robin.James@ec.gc.ca>.
Skip Willis, Duncan Rotherham, ICF Consulting, Tel: (416) 341-0382

Ontario NO_x and SO_2 Allowance Trading

Description: The Province of Ontario has created an allowance set-aside for air emissions trading that can be allocated to energy savings and renewable energy projects.

Methodology: Emission factors representative of emissions during the day and the night in Ontario were predetermined (see Table A6). They are given below for the year 2000, and are to be calculated for each hour of the day, as a function of electricity saved or generated during that hour, and for different seasons:

Table A6 – NO_x and SO_2 emission factors

NO Intensity (kg/MWh)

Period	Day	Night
Winter 1	1.3	1.1
Spring	1	0.8
Summer	1.1	1
Fall	1.2	1.1
Winter 2	1.3	1.1

SO_2 Intensity (kg/MWh)

Period	Day	Night
Winter 1	5	4
Spring	3	2
Summer	4	3
Fall	3.5	2.5
Winter 2	5	4

Emission factors are corrected periodically to represent changes in the Ontario electricity system, but have not been updated since 2000. The factors are calculated with a simplified marginal dispatch methodology: only coal plants are considered, and their contribution to electricity generation on the margin is determined based on seasonal load factors (plant capacity factors). These factors are modified for day and night time, based on knowledge as to which plants operate on the margin during those times. Different emission factors are also used for each plant, depending on actual emissions.

Relevance: While having model character for the CEC work, the methodology does not seem to have much bearing on other Canadian initiatives to quantify GHG emissions reductions from renewables.
Discussion: The way the factors are provided is very convenient, and should be considered by the CEC working group. The methodology takes into account daily and seasonal changes both of the electricity system itself and of the displacing activity, which allows accounting for differences in generating activity between solar PV and wind, for example.

Documentation: Ontario Emissions Trading Code, *Air Policy and Climate Change Branch,* Ontario Ministry of the Environment, January 2003

Web site: http://www.ene.gov.on.ca/envision/air/etr/

Contact: John Hutchison, Senior Policy Advisor, Ministry of the Environment, Air Policy and Climate Change Branch, Toronto, ON, Tel: (416) 314-6789, e-mail: <john.hutchison@ene.gov.on.ca>

Federal Green Power Purchasing

Description: The Canadian federal government has a target to procure 20 percent of its electricity from green power sources by 31 March 2006. CO_2 emission reductions are transferred to the government by these contracts.

Methodology:
a) Alberta/ENMAX
The government used data on total electricity consumption in Alberta and 1997 utility-owned fossil-fuel plant-specific CO_2 emissions and hourly electricity production. Emission factors for each of all utility-owned coal-fired plants; natural gas-fired plants; and oil-fired (diesel) plants were developed. The average 1997 Alberta utility CO_2 emission factor for electricity on the Alberta Interconnected Electric System was 0.86 tonnes/MWh, and was derived from hourly averages of all plants throughout the year, considering their actual generation at each hour. The calculation is reiterated each year based on generation data from the previous year. The methodology does not exclude electricity exports from the calculation, but assumes that the emissions from electricity exports are attributed to Alberta. Likewise, a fossil unit in British Columbia that delivers electricity to Alberta was assigned a zero emission factor. The methodology was approved by the Greenhouse Gas Emission Reduction Trading (GERT) Pilot, which ended in 2002.

b) Ontario RFP
CO_2 Emission factors were derived for different seasons, as well as day and night time in Ontario (see Table A7). The government reserves the right to update emission factors annually. The methodology is the same as the one used for deriving Ontario's marginal

emission factors for NO_x and SO_2 emissions displaced by renewable energy (see previous section).

Table A7 – Emission Factors for Federal Green Power Procurement in Ontario

CO_2 Intensity (kg/MWh)				
Period	Number of hours in Daytime (07:00-18:59) period	Daytime Displacement Co-efficient (kg/MWh)	Number of hours in Nighttime (19:00-06:59) period	Nighttime Displacement Co-efficient (kg/MWh)
Winter 1 (January 1 to March 1)	720	990	720	838
Spring (March 2 to May 31)	1092	762	1092	609
Summer (June 1 to September 30)	1464	838	1464	762
Fall (October 1 to November 30)	732	914	732	838
Winter 2 (December 1 to December 31)	372	990	372	838

Relevance: The approach is one out of several that are being used by federal initiatives. It is not possible to say which of the approaches will prevail.

Documentation: Greenhouse Gas Emission Reduction Trading Pilot Project Documentation: Green Power Sale by Enmax, and Purchase by Her Majesty in Right of Canada (as represented by Environment Canada and Natural Resources Canada), with Assignment and Transfer of CO_2 Emission Reductions. February 22, 2000 (available from the GERT web site)
REQUEST FOR PROPOSAL (to purchase 90 GWh of green power in Ontario). Public Works and Government Services Canada, Appendix A, October 1, 2003

Discussion: The methodology is simpler than the current model used by the PERRL initiative, but is more accurate than the proxy factor currently suggested for the Offset System in Canada (see previous sections). The working group has to decide whether an approach that does not use marginal emission factors is accurate enough for its purposes.

Web sites: http://www2.nrcan.gc.ca/es/erb/erb/english/View.asp?x=464
www.gert.org

Contact: Mr. Leslie Welsh, Head, Sustainable Energy Section, Environment Canada, Oil, Gas and Energy Branch, Hull, Quebec,
Tel: (819) 953-1127, e-mail: Leslie.Welsh@ec.gc.ca

Other Canadian Initiatives

Some utilities have green power marketing programs. They usually use a system average approach to calculate GHG emission reductions from green power. BC Hydro uses a proxy factor, which is 0.36 tonnes per MWh.

The federal government pays a Wind Power Production Incentive of 1 cent per kilowatt-hour. Emission reductions from this program are calculated using a factor of 1.15 tonnes per MWh.

* * *

Appendix 2: Comparison of Calculation Methodologies

Table A2-1 Key attributes and conditions favoring different approaches [*Tellus 2001*]

Methods	Pros	Cons	Conditions favoring approach
System average - *Annual average* - *Time of use average* - *Average excluding known baseload facilities*	• Very simple and relatively inexpensive • Predictable (limited annual variation), even if ex post approach used • Unambiguous and removed from need to apply judgment	• Weighted toward low-cost baseload resources (e.g. hydro, nuclear, coal) that are least likely to be avoided by new project (in traditional, centrally dispatched systems) • In such systems, it is an inaccurate measure of avoided electricity • Excluding baseload from average requires judgment in setting threshold	• Deregulated systems where strategic bidding creates a system without clear definitions of peak and baseload resources • Other methods deemed too costly or difficult to implement (data availability) • Smaller projects where transaction costs must be kept low
Operating margin - *WAMER* - *TOU WAMER* - *Dispatch modeling*	• In principle, more accurate than a system average method • TOU WAMER can readily capture effects of projects with variable load shapes (e.g. load shifting and intermittent renewables)	• Can require confidential dispatch or bid data • WAMER approach attributes some emissions to peakload and intermediate plants, even for baseload projects • Difficult to determine true marginal resource in hydro dominated systems • Assumes no effect on system expansion	• Traditional, centrally dispatched systems • Smaller projects that are less likely to affect new builds • Larger projects during situations of excess capacity • Projects with variable load shapes
Build and combined margin - *Proxy plant* - *Recent/planned additions benchmark* - *Optimization/ dispatch modeling*	• Can be simple, inexpensive to develop and administer • Amenable to fixed, ex ante, predictable baseline • Combined (e.g. modeled) approaches can capture both marginal effects	• Can be difficult to judge and verify build margin • Assumes entire effect is on system expansion • Build margin may be subject to rapid change due to fuel prices variation and single, large projects	• Capacity value of resource is high (MW) • Project is long-lived • Smaller projects where transaction costs must be kept low • Supply constrained systems

WAMER: Annual weighted average marginal emission rate, based on annual load profile
TOU (“time of use”), showing exactly when each plant is working

Table A2-2 Pros and Cons of Different Methodologies

	System Average (OM1)	Average excluding low cost/must run facilities (OM2)	Dispatch decrement analysis (OM3)	Dispatch model simulation (OM4)
Accuracy	Low	Improved	Higher, though can be difficult to determine true marginal resources in hydro-dominated systems	Depends on assumptions
Data Availability (Practicality)	High	High	Limited. May be considered confidential.	Limited model availability.
Cost-effectiveness	High	High	Perhaps for large peakload saving projects when using time-of-use approach	Potentially costly model runs feasible only if project and credit flow is very large.
Wide applicability	High	High	Limited	Low
Transparency	High	High, though deciding what to exclude introduces judgement and potential bias	Medium to high, if calculations are clearly presented.	Low, given the dependency of results on detailed and often poorly documented model parameters.
Conservative (relative to most accurate OM methods 3 and 4)	No, especially in systems with a large proportion of old fossil fired plants. In systems with considerable low cost, low C may actually dissuade investment.	Must be judged on grid-by-grid basis.	N/a	N/a
Consistency	High	High (providing there are common definitions of what facilities to exclude)	High, providing data is adequate	High, providing models are well-calibrated to actual circumstances
Reproducibility	High	High	High if access to necessary data	Medium (only if access to the models)

Source: Kartha, Sivan and Lazarus, Michael: Practical Baseline Recommendations for Greenhouse Gas Mitigation Projects in the Electric Power Sector (OECD and IEA Information Paper). SEI-Boston/Tellus Institute, with Martina Bosi, International Energy Agency, May 2002

Appendix 3: Some Thoughts/Suggested Work Plan

Some thoughts and comments
on reviving the working group on a
common methodology for quantifying environmental benefits
from renewable energy generation

THESIS 1 – There is a great need to find a common methodology.

Many people I have talked to confirmed their interest in this work. At the moment, many different organizations, governments, and groups are working on aspects that concern our work, or are actually trying to come to an agreed methodology themselves. Examples are national governments trying to establish and refine their carbon emission inventories, the CDM Board, Indian government, World Resources Institute, etc.

Comments:
Kerri Henry, Environment Canada: "Canada is also working with different gov't funding programs to consolidate their methods. The focus is on ensuring that proponents / project authorities consider the options and make it clear what they are doing. We are working on some consistent paperwork but are not expecting that we'll end up with one consistent methodology among all groups— (not that it means we won't try."
Jim McConnach, IEEE: "For Theses 1 and 2, I would recommend that it is more important to establish which methodologies have the ability to meet globally accepted performance standards for quality, certainty and accuracy and then leave it to proponents to choose the methodology that is most cost effective and best suited for their specific project technology and circumstances."

THESIS 2 – A common methodology will eventually emerge, whether we get involved or not.

The question is not, do we need a common methodology, but the question is, do we want to get involved in defining it? A clear need for it is established, so it is only a question of WHEN, but not IF, it will be developed, and BY WHOM. If it is important to us, we should get involved NOW. The CEC is in a unique position to facilitate such work in North America, and possible broaden the scope of current work started by the World Resources Institute. A clearinghouse function may be useful, but does not reflect the need for a methodology and the CEC's potential to foster its development.

THESIS 3 – This work is broader than renewable energy.

As initially stated by the CEC, this work not only concerns renewable energy, but also energy efficiency, combined heat and power, fuel cells, effects of distributed generation and any other activity that displaces electricity from the grid. We have to look further than just one application, and learning from existing initiatives and practices in other areas may help us along.

Comments:
Kerri Henry, Environment Canada: "Agreed. If we are moving beyond renewable energy, there are a lot more programs already underway as well."
Jim McConnach, IEEE: "I agree."

THESIS 4 – This work is broader than North America.

While we want to know about the environmental benefits of renewable energy on the North American power grid, the question becomes far larger if we think of applications of this work such as CO_2 offsets and other emission reductions that may lead to offset trading across borders and continents. Mechanisms such as the Kyoto Clean Development Mechanism should be considered in further work, and links established with working groups involved in Kyoto and maybe other international mechanisms.

Comments:
Kerri Henry, Environment Canada: "Canada is looking to follow the international lead—e.g., using ISO standards for verification, EU trading schemes etc., since Canada has the need to be able to trade with Kyoto countries."
Jim McConnach, IEEE: "I agree."

THESIS 5 – Different methodologies MAY be suitable for different fields of application.

There are four main fields in need of quantifying environmental benefits:

- **Government programs**, such as green power procurement or energy efficiency programs
- **Carbon inventories**, whether at the national, regional, municipal, or corporate level. Carbon accounting is becoming more and more important—not only for Kyoto compliance, but also for carbon risk management and benchmarking. Accounting at different levels should possibly be compatible so that the numbers still make sense once they are all added up to obtain figures for a larger entity.
- **Offset and allowance trading** – under Kyoto or similar programs, such as the North Eastern States Regional Greenhouse Gas Initiative.
- **Renewable energy certificate trading** – regional, cross-border registries are emerging both in the East and the West (Western Renewable Energy Generation Information System). These are the foundations for international trade in green power and related environmental benefits.

It may (or may not) be advantageous to select different accounting systems for

a) inventory needs (government programs and carbon inventories) and
b) trading issues, such as offsets and certificates

This would suggest that there are different paradigms in each field: trading is essentially meant to level the playing field, but also to encourage environmentally benign behaviour and investment. Inventories simply want to assess the "true" value and effect of a measure. There are interesting cases to learn from, as allowance markets for emissions have been in existence for a long time in North America. For example, the SO_2 trading system is a bad example for renewables as the benefits allotted to them were far too small to encourage their involvement in allowance markets. On the other hand, both US NO_x and SO_x markets involved renewables by setting a fixed amount of emissions displaced by MWh, which was easy to calculate and universally applicable throughout the same airshed. Such elements should be considered when coming to a common approach for environmental benefits in general, and program managers or consultants may be able to provide valuable input for our task.

Comments:

Kerri Henry, Environment Canada: "Government programs have a lot of different goals. Some will obviously be to support projects that reduce emissions but others might have a different focus of supporting emerging reduction technologies even if no reductions (and maybe even some increases) occur during the project phase. SDTC (Sustainable Development Technology Canada) is one of our larger funding programs and it wants to help new technologies get to market. Don't want methodology for calculating benefits to be so rigorous as to be a dis-incentive.

The goal of all government programs and offset projects is to reduce the amount of emissions / increase reductions. The point is not to make all initiatives / projects work within a certain trading system. There is a need to make sure that quantification is not too onerous. E.g., different streams within one methodology for small projects, trading projects, etc. Inventories don't have to deal with estimating "what would have happened" baselines."

Jim McConnach, IEEE: "I support Thesis 5, in that different technologies and programs will likely need different methodologies. There is no "one size fits all" but as recommended above, as long as the different approaches achieve a commonly agreed performance in the quality, certainty and accuracy of results then there is freedom of choice while achieving reasonable consistency and credibility of outcomes. The latter is a must for viable GHG markets."

Namat Elkouche, Natural Resources Canada: "In TEAM we have developed the SMART (System of measurement and reporting for technologies) protocol and we participate in the Accepted practices working group. This group gathers people from various governmental programs, such as STDC, FCM, GHG Verification Center, Agriculture Canada, and PERRL. It seems to me that it would very useful but hard to align all programs and needs under one single methodology (whether for renewables or other sectors). This is because every program has different needs and different deliverables, objectives, etc... In the same way, the project needs are different, i.e., some projects are interested in applying the CDM scheme while others are interested in a different scheme, such as Offset (in the future). On the other hand, I think it would be useful to have a methodology that would allow you to select various baseline calculation methods (i.e., for baseline selection and emission factors) depending on the selected scheme as well as the project conditions, and that would accommodate for the variations of the project needs as well as the program needs (when applicable) under certain conditions. I also think that the development of emission factors, within the CEC channel, would be very useful, and I think the suggested effort of integrating it into an Internet-accessed program, would indeed lower the costs for GHG reduction calculations, particularly in the case of renewable energy projects."

Jeff King, Northwest Energy and Conservation Council: Regarding the first and fifth of the six theses, it is not clear that there is a need to establish common methodologies except for specific applications. Otherwise, it may be best at this stage to encourage innovation and not force adoption of any specific methodology except for routine applications having legal or economic implications. Even for these applications innovation should not be discouraged.

THESIS 6 – Settling on a common methodology will be a policy decision, not a scientific one.

When it comes to the details, it is virtually impossible to determine the REAL benefits of renewable power generation. While determining what is displaced on the margin is probably the most accurate way of quantifying immediate benefits, this leaves out other aspects, such as the displacement of other generation in the mid and long term (build margin, e.g., the construction of the next gas-fired power plant). It may also be very complicated and expensive to determine actual environmental benefits with the greatest accuracy, as the marginal unit will change over time, and as more renewables come online, the picture may change, and numbers may have to be reviewed often, possibly each year. Such a practice would create uncertainty as to the amount of benefits to be derived from renewables, and therefore uncertainty among investors as to how many allowances or credits they may get from an operation, or what the value of extra benefits would be. It is desirable to have a methodology that will result in unchanged results over a long period of time, at least as far as credit and allowance markets are concerned.

Comments:
Jim McConnach, IEEE: "Thesis 6 may be reworded to refer to settling on those methodologies that meet globally agreed performance standards for quality, certainty and accuracy. This should enable a greater reliance on science and what is practical in the decision making although it is likely not possible to rule out the influence of policy."

Suggested Work Plan for 2004

1. Working Group members to reconfirm interest in the process and invite additional participants to join the working group.
2. Prioritise the work— (for example, by concentrating on MARKETS first, and INVENTORIES second, or creating two groups that deal with these two categories to determine whether we need ONE or TWO methodologies.
3. Expand on the existing background report and describe new and international developments, such as methodological considerations flowing from the CDM MethPanel's work, existing and emerging emission allowance trading markets, etc. (see below)
4. Identify and network with more key stakeholders and existing initiatives
5. Reconvene this year to discuss further steps
6. Revamp the CEC web site to incorporate the existing background report, as well as links to key initiatives that we want to work with.

Comments:
Kerri Henry, Environment Canada: "I'm assuming that "inventories" refers to national inventories. Since there are already international rules on this, trading would seem to be a priority. If talking about company or project inventories, there would be usefulness to having consistency—particularly for multi-nationals—but national requirements of Kyoto are still going to be paramount. Perhaps the focus would be determining differences in methods?"
Jim McConnach, IEEE: "Regarding the suggested work plan, the IEEE P1595 Task Force would be delighted to participate in taking this work forward to a practical conclusion. The IEEE brings the value and credibility of an internationally recognized Standards body (with strong links to the IEC) with a proven track record in developing performance standards in the electricity sector. Funding is a barrier to the participation of most Task Force members in meetings or workshops, including myself, as we are all independent volunteers. However, much can be achieved on the Internet and I look forward to the possibility of working with the CEC and WRI/WBCSD on this worthwhile endeavor."

Appendix 4: Taking a Stab at the Build Margin

Usually, the build margin is calculated either by taking a proxy technology—natural gas combined cycle in many cases—or by either taking the average emissions of plants added over the past five years, or the last 20 percent. It could also be calculated using projected plant additions if this information is available. All these approaches have serious shortcomings, as explained below:

Which plants are representative: In Ontario, energy policy is one the main topics in the wake of the 2003 blackout. Ontario plans to reactivate several nuclear plants, build additional power stations, and has set targets for 2,700 MW of low-impact renewable energy projects and five percent improved energy efficiency. At the same time, the province wants to shut down several thousand megawatts of coal-fired generation. So the mix of measures suggested will displace this coal generation. If the build margin was calculated based on projected plant additions, entirely wrong results would follow because nuclear would be a major part of these additions, but is not displaced by renewable energy. Likewise, using a "past 20 percent" or the last five plants built in Ontario would likely underestimate the emissions displacement, as such an approach would not only include coal plants.

Another example is Alberta, where up to 2,000 MW of new coal-fired plants may be built by 2020. However, many of these plants will replace 890 MW of existing plants that are to be retired in the same time frame. These plants are unlikely to be displaced by renewable energy projects. It would therefore be necessary to determine which new coal plants are replacing existing generation, and which are truly additional and might be displaced by the increased deployment of renewable energy plants. Likewise, using the average of past plant additions to determine the build margin may include some plants that are merely replacing older ones. The simple approaches suggested by the CDM Consolidated Methodology and the WRI Road Test Draft therefore seem inadequate to calculate a build margin in North America.

Increasing, stable, or decreasing demand: The question what the build margin should be presumes that there actually is a build margin. However, a true build margin only exists where power consumption rises. If power consumption were stable over time, there would only be plant replacements. Of course, renewable energy could then be assumed to displace some of these replacement plants but it may be more appropriate to determine those plants based on anticipated plant retirements than on plants added in the past. This could also incorporate the expected performance of future plants, which may outperform that of formerly built plants—for example, in the case of more efficient "clean coal" plants, which are being heavily promoted in North America.

In case demand decreases, new construction can be expected to be reduced, and so are build margin effects of renewable energy project. These plants would then have more of an effect on the operating margin than on the build margin.

Share of the build margin in the combined margin: The previous problem leads into another criticism of the build margin concept—the question of determining the share of the build margin in a combined margin approach. The CDM methodology suggests a 50/50 split between operating and build margin in order to determine the overall effect of additions of on-grid renewable energy facilities. However, this split is an arbitrary one, and one could argue for other splits. Certainly, intermittent resources will have a lesser impacts on new plant additions than firm resources. However, it is impossible to say what the right allocation between these two methodologies would be at any given point in time.

Amount of emissions displaced: It is often assumed that the build margin equals the emission factor of the technology displaced. For example, if combined cycle natural gas were the default technology that would have been built in the absence of the renewable energy project, a factor of 370 kg of CO_2 per MWh could be applied. However, this assumption is erroneous because a natural gas power plant mostly delivers peaking power and does not run 100 percent of the time. The 370 kg/MWh factor would therefore only apply at the moments the default plant would have been running. As renewable energy plants can be expected to run at their maximum possible output all the time, they must necessarily displace other sources at different times. It would then be necessary to determine how the default displaced plant would have worked with other plants in the absence of the project, making the determination of the true build margin equal to determining the future operating margin if the default technology had been built.

When does the build margin apply: The CDM methodology applies the build margin from the very start of a project. However, the construction of additional conventional power plants may only be scheduled for later years. Also, the default project will have a certain life time, for example 25 years, after which it will be decommissioned and no more emissions are displaced. The question of what the new build margin is after decommissioning would have to be answered anew at that point in time—unless the renewable energy project is also decommissioned within the same timeframe.

Building the build margin into the operating margin: Figure A4-1 displays an imaginary scenario, showing a long-term load curve in a situation where annual electricity demand increases slowly over time. Assuming that a combined cycle natural gas plant is the default technology displaced, such a plant could be expected to be built in the year 2005 if it was determined in 2000 that a new plant addition was necessary to cover demand in 2005 and beyond. Before the plant would be built, additional power has to be imported to cover demand, and after the plant is build, excess generation capacity could be used to export power from the grid for some years, with the associated emissions being passed on to the buyer.

In order to determine the build margin, the model could assume that this default plant will actually be built. This assumption is actually very realistic, as it is hardly possible anymore to build merchant plants without a power purchasing agreement since the Enron crisis in North America. This means some planned plants cannot be displaced by renewable energy projects as they will go ahead anyways due to the power purchasing agreement. However, even if the plant is not built but only used as a proxy for determining displaced build margin emissions, the model could incorporate it as a virtual plant that operates in concert with existing power plants and is displaced by the addition of renewable energy projects when it operates at the margin. The future operating margin would therefore be calculated using both the existing plants and the default new technology that would have been built in the absence of the project, using a dispatch model.

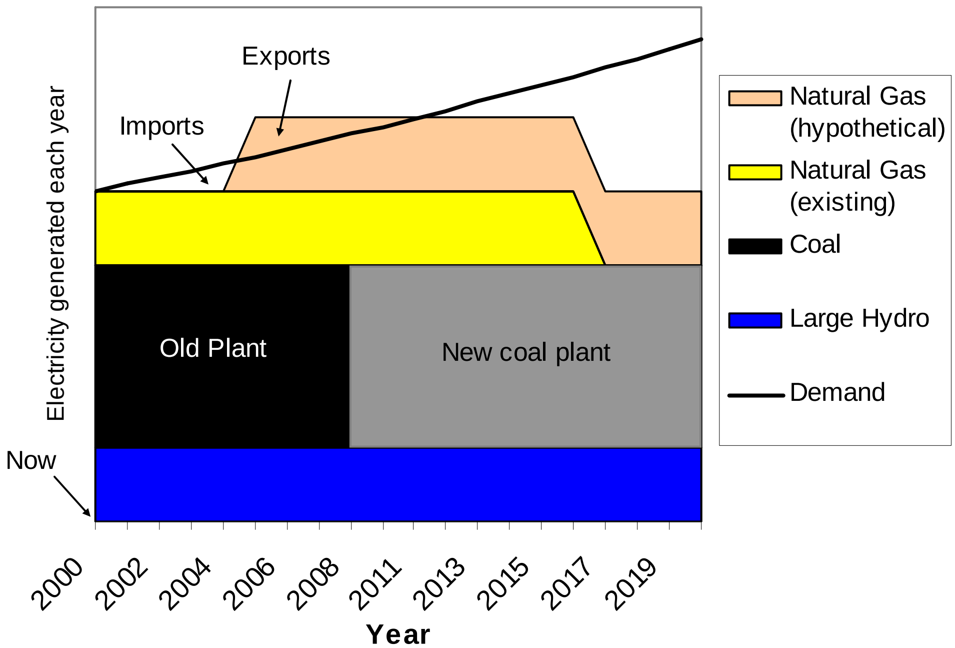

Figure A4-1 Hypothetical Situation with Natural Gas at the Build Margin (Year 2000 = now)

In this case, it depends on what would have been imported instead of the electricity now produced with renewables whether there is a net gain or loss in emissions displaced by the renewable energy project over using the operating margin: if large hydropower is imported to make up for generation deficits, the project displaces more emissions than would have been the case if the build margin had not been applied. If coal-based electricity is imported, then the project will actually gain less emission reduction credits, as it is seen as displacing electricity from the hypothetical natural gas plant, not from imported coal-based power.

It is also obvious that a new coal plant has been built in 2008. However, this plant merely replaces an older, existing plant. It will therefore reduce the emissions displaced by the renewable energy project at times when the coal plant operates at the margin, but does not affect the build margin. The existing natural gas plant is decommissioned in 2018. What will be built to replace this plant is not determined yet, as the time horizon for the model forecast is assumed to be ten years.