World Bank Carbon Finance Business

Issues Summary
Electric Grid Baseline Workshop
Buenos Aires, Argentina
December 8, 2004

April 1, 2005

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Preface

This paper has been prepared by the author as part of a consulting engagement with the Carbon Finance Business of the World Bank and was financed with funds from the Ministry of Environment of the Government of Spain. The views and opinions expressed herein are solely those of the author and do not represent the official position of the Carbon Finance Business, the World Bank or the Spanish Ministry..

1.0 Introduction

1.1 Background and Funding of the Workshop

The Carbon Finance Business of the World Bank (CFB) and its predecessor, the Prototype Carbon Fund (PCF), have been actively pursuing carbon reduction projects for several years in numerous countries. Successful projects result in negotiation of an Emissions Reduction Purchase Agreement (ERPA) with the project sponsor that specifies quantities of CO2e reductions that will be purchased over a specified period of time and at a specified price. Many of those projects included displacement of electricity previously produced by power plants that are part of integrated central grid networks. Determination of the emission reductions that qualify for purchase under the ERPAs obviously required baseline studies to establish a benchmark for comparison. Since many of these projects predated formal promulgation of rules and methodologies by the Clean Development Mechanism (CDM) Methodology Panel, PCF-CFB had to develop their own principles and standards for baseline development.

The CDM Methodology Panel has been charged with the daunting task of establishing acceptable baseline methodologies for a very wide range of potential carbon reduction projects. The specified approval process relies on submittal of project specific methodologies by project sponsors and reactive issuance of approved methodologies by the CDM Panel. For electric sector projects, baseline issues have proved to be complex and controversial. As a result, the CDM Methodology Panel which has very limited resources has found it very challenging to meet the demand for timely response to all of the proposed new methods and project developers have found it very difficult to anticipate what level of carbon reductions they could use to assist in financing their projects. Frustration has also grown due to the lack of established channels of communication between the project development community and the CDM regulators.

Given this setting, the CFB chose to sponsor a full day workshop in conjunction with the Kyoto Protocol Conference of Parties held in December, 2004 in Buenos Aires, Argentina. The workshop was designed to bring together a diverse group of experts with substantial experience in electric grid baselines to share their experiences and to provide an unprecedented opportunity for open dialogue between the CDM Methodology Panel, representatives of project sponsors, and many other stakeholders in the ongoing development of carbon markets.[1] CFB wishes to formally acknowledge the critical support and funding for the workshop that was provided by the Ministry of Environment of Spain and by the Spanish Office of Climate Change.

1.2 Report Purpose

The workshop was well attended and provided fertile ground for productive exchange of experiences and ideas on how to improve electric sector baselines and to accelerate the regulatory process for approval of new methodologies. While the level and breadth of issues raised was admirable, the session did not close with a clarion call to action or a

[1] A full list of the workshop participants and their affiliations is provided as Annex A to this report.

clear indication of how to build on the results of this workshop. The purposes of this paper are to briefly characterize the challenge faced by the CDM Methodology Panel; to recap the most significant issues discussed in the workshop, and then to focus on future actions that can accelerate the preparation of high-quality electric sector baselines.

1.3 Report Outline

Section 2.0 of the report begins with an overview of the challenge faced by the CDM Methodology Panel in their role as the regulator of baseline methodologies and of the allowable carbon credits that flow from those baselines. The report then provides a brief summary of the current state of the art in electric sector baseline methodologies to provide the framework for discussion of key open issues that were identified in the workshop.

Section 3.0 then offers a list of conclusions that can be drawn from the workshop and addresses future research and communication agendas that would continue to build on the impressive start in Buenos Aires. Specific recommendations to the CDM Methodology Panel are also provided.

Two Annexes to the report provide the list of attendees of the workshop and brief abstracts of the presentations that were given. The list of attendees should facilitate future networking among the parties. Full copies of each presentation are available on request from Carbon Finance Business. CFB can be contacted through their website.[2] The abstracts are provided here simply to help readers identify the presentations that will provide the information of primary interest to them.

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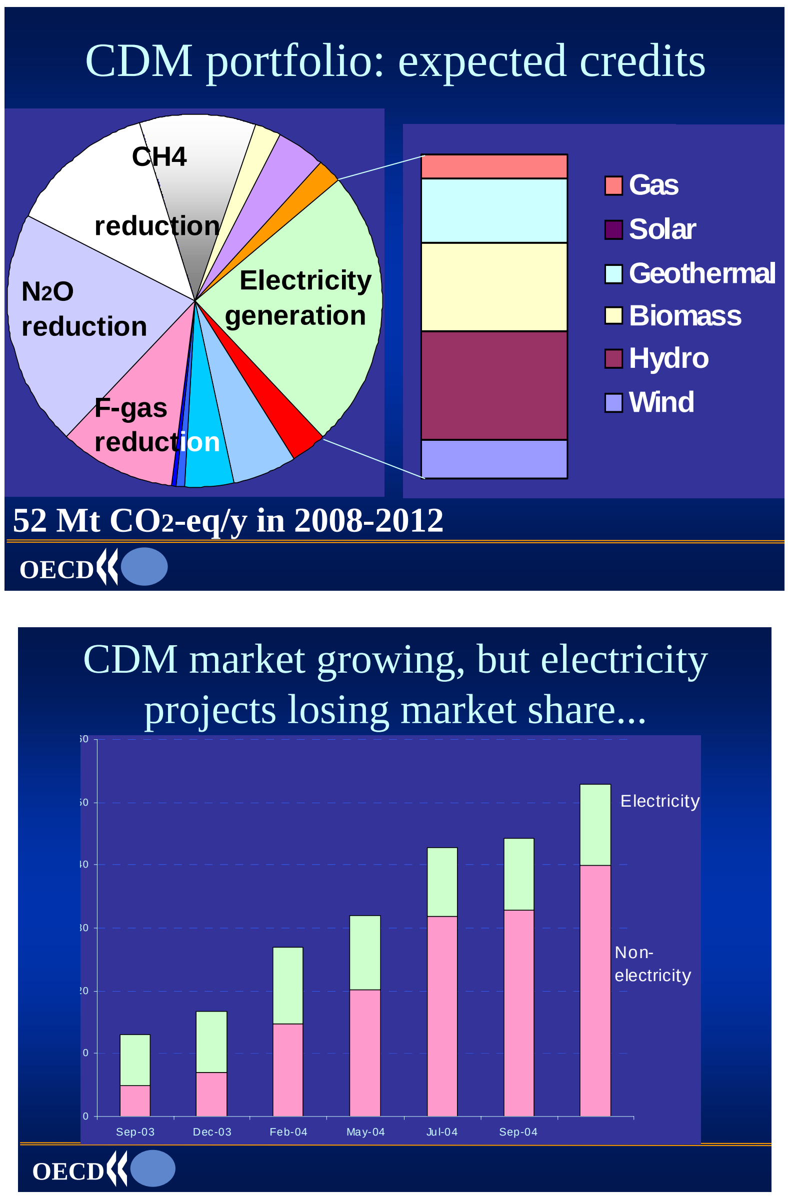
[2] http://carbonfinance.org/Router.cfm?Page=DocLib&Dtype=50&ActionType=ListItems

2.0 Key Issues From The Workshop

2.1 The CDM Challenge

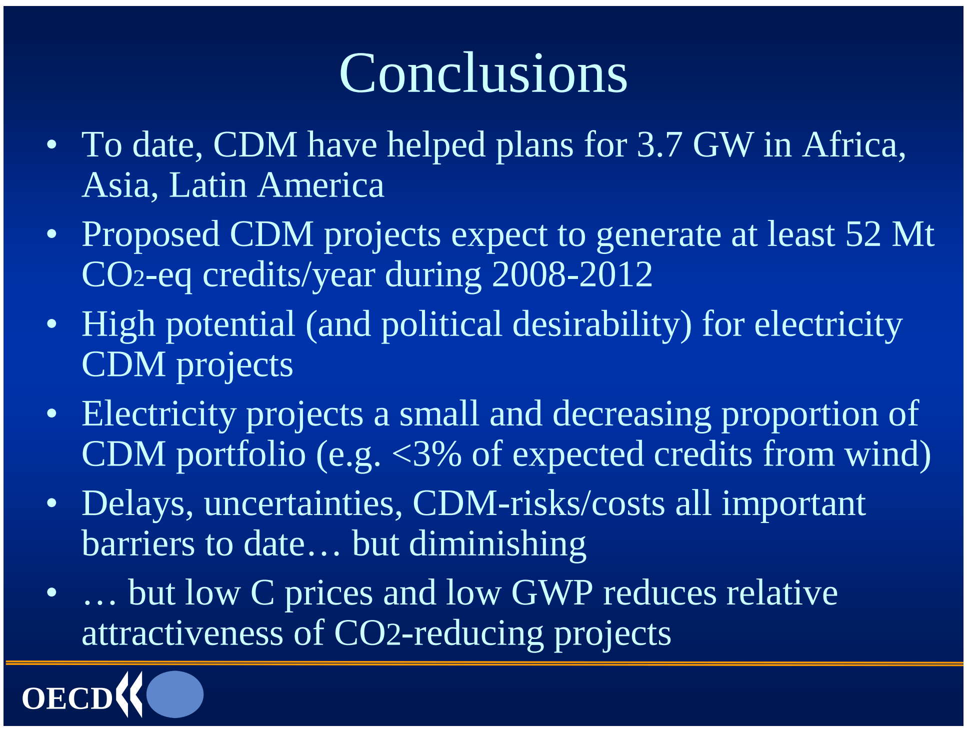
Scattered throughout the presentations was broad recognition from many perspectives that the CDM Methodology Panel has been charged with a very large task in attempting to provide timely approvals of baseline methodologies that adequately cover the wide range of legitimate variations in electric sector baselines. Coupled with the resource limitations that the Panel has faced in its role as regulator, clear and comprehensive guidance for all developers of projects in this sector has been slow to evolve. The upshot of this situation has led to a shortfall of electric sector carbon projects relative to early expectations. Jane Ellis of OECD usefully characterized the situation as shown in Figure 1.

Figure 2-1 Electric Generation Projects in the CDM Portfolio



Although electric sector projects constitute about half of the current CDM portfolio, they account for slightly less than 25% of expected CO2eq reductions in the first Kyoto crediting period. In part, this situation has developed because the carbon-based share of electric sector project financing is relatively low and the CDM risk has been viewed as relatively high absent early and clear guidance on baselines and resultant estimates of emission reductions that can be claimed. Ms. Ellis concluded her presentation by noting that delays, uncertainties, CDM costs and risks have all been important barriers to electric sector carbon reduction projects but these barriers are now diminishing with the introduction of more approved methodologies with wider potential application. She summarized her views in the slide shown in Figure 2.2.

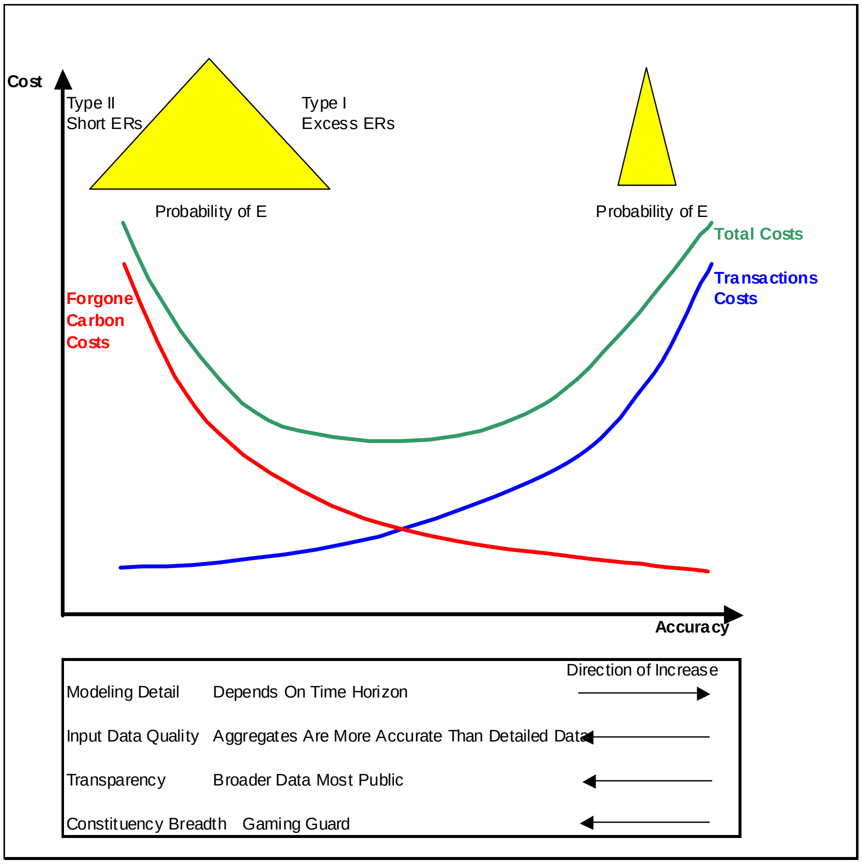
Figure 2-2 Jane Ellis' View of The CDM Electric Sector Portfolio



Ken Newcombe of CFB-PCF, in his keynote remarks, aptly noted the countervailing forces that have acted on the CDM Methodology Panel and the Executive Board. Under the Marrakesh Accords, these bodies were assigned regulatory and policing functions to assure that carbon payments are associated with legitimate reductions that would not have occurred absent the proposed project. Certainly this mandate provides a clear bias toward caution in approval of baseline methodologies that could be used or abused over a very wide range of circumstances. At the same time, the entire carbon community has a common interest in assuring that legitimate reductions are recognized and rewarded without requiring prohibitive transactions costs for baseline development and/or monitoring and verification. Mr. C. S. Sinha in his comments during the discussion session reinforced the view that the conservative bias of the CDM regulators has led to problems in assessing project additionality. This has been a contributing factor to in the underperformance of electric sector projects in stemming the growth of greenhouse gas emissions in rapid growth developing nations.

Duane Kexel of Power System Engineering echoed and expanded Ken's characterization in the graphic shown in Figure 2.2.

Figure 2-3 Baseline Cost Vs. Accuracy Trade-offs



We can usefully think of the CDM challenge as an attempt to reach the appropriate balance between the costs of foregone carbon reductions and the accuracy of baselines that result from the methodologies that are approved by CDM. Foregone carbon reductions occur in two basic ways. CDM could be excessively lax in its regulatory function and exaggerate the legitimate reductions that are realized. Alternatively, CDM could be excessively stringent and provide inadequate incentive to make really good carbon projects viable. While increased baseline accuracy is generally desirable, this will not be the case if the incremental cost of improved accuracy is prohibitive in terms of methodological feasibility and in terms of transactions costs. It is useful to recognize that all emission reductions estimates are subject to some level of estimation error and to establish a goal of striking the appropriate balance between cost and accuracy.

Ken Newcombe further amplified the CDM challenge in the context of timelines. The stark reality is that the first crediting period runs from 2008 through 2012. This is currently the maximum period in which an investor can be certain of receiving payments for carbon reductions under CDM. Electric sector projects typically have relatively long lead times that may range from one to five years. Decisions on a project with a three year lead time, must be made now if the project is to be online and earn carbon credits over the entire five year crediting period. Even with credits over the full period, carbon may only cover something like 10% to 15% of total investment costs for typical electric sector projects.[3] If the effective crediting period begins later than 2008, the chances for carbon to influence investor choices are substantially reduced. Thus, time is of the essence in providing clear and practical baseline guidance.

To summarize, the majority views at the workshop converged on these points:

- Electric sector projects have not fulfilled their expected share of the CDM portfolio of carbon reduction projects.
- Failure to tap the full set of potential electric sector projects would leave substantial opportunities to reduce carbon emissions untapped.
- Electric sector baselines are more complex and heterogeneous than the baselines for other GHG projects.
- The lack of comprehensive regulatory guidance from CDM MP and EB for electric sector projects has contributed to the shortfall of these projects in the CDM portfolio.
- Process and resource constraints have historically constrained the CDM Methodology Panel from providing the level of timely guidance that is needed to fully exploit the potential in this sector.
- The time window for accelerating projects in this key sector for the first crediting period is narrowing quickly.
- Balance is needed between the precision and the costs of approved methodologies.
- The consolidated methodology is a good step in the right direction but it cannot reasonably be applied to all possible grid settings. In fact, literal application in some of the circumstances cited will lead to indefensible estimates of ERs.
- CDM is open to new approaches but the historic process of reactive response poses excessive risk to project developers and does not support timely financing of projects that rely to any extent on carbon finance. Projects that do not rely on such financing are probably not additional.
- As a prescription to remedy this situation, the paper calls for commitment to a proactive program of expanding both the dialogue and the body of approved approaches through the next steps that have been proposed.

The workshop also provided open recognition that the current combined margin approach is not a fait accompli and that much room remains for extension and refinement of the ACM0002 guidance. Mr. Lazarus provided the forward-looking summary view shown in Figure 2.5

[3] Most carbon credits can only be monetized on a pay on delivery basis and are not directly available to cover upfront project investment. The percentages indicated here reflect present worth figures for carbon credits compared to upfront investment costs.

Figure 2-4 Mr. Lazarus Summary View

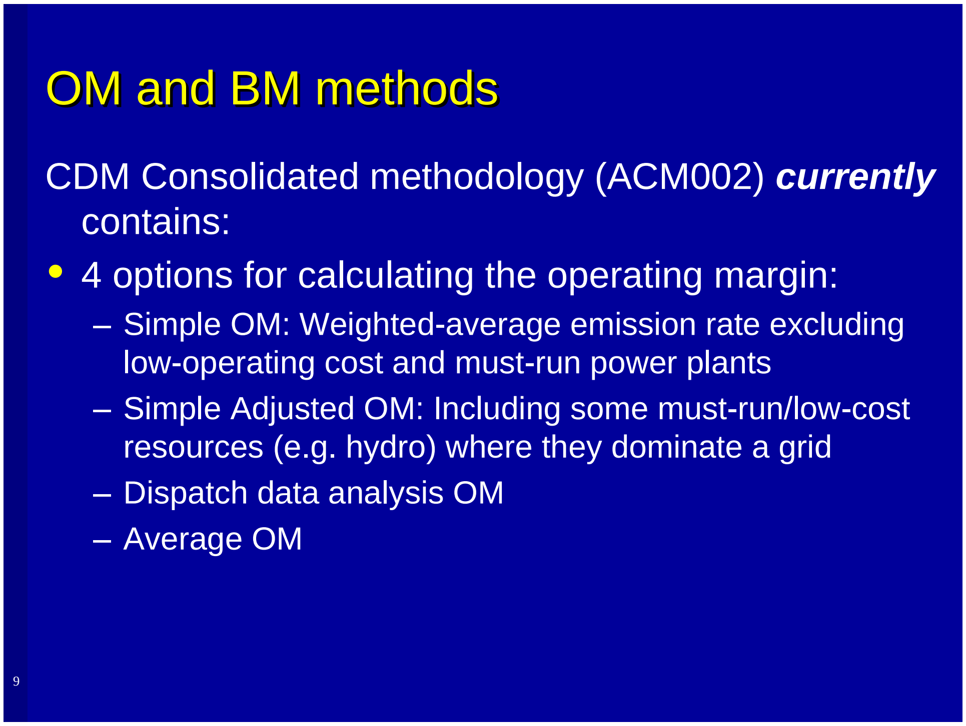
2.2 Current Status of the CDM Response

While the previous section has suggested that substantial room remains to expand the body of formally approved electric sector baseline guidelines, this does not suggest that the CDM Methodology Panel has not already made significant progress in meeting their mandates. In fact, most of the workshop presentations were responding to particular methodologies that the Panel has defined and the Executive Board has approved. In particular, the CDM Methodology Panel has very usefully distinguished operating margins (OM) and build margins (BM) as a fundamental segmentation of methodological issues. OM margin analysis attempts to identify the displacement impact of a proposed project in terms of its influence on how existing generation assets are used to satisfy the ongoing demands for electric energy. In many electric markets this will be a short run analysis since the portfolio of generation assets remains fixed. The BM analysis, however, focuses on the impact of a proposed project on the capacity expansion path within the relevant electric market. The context is now focused on future investment decisions rather than operating decisions.

2.2.1 Accepted OM Methods

The most recent and comprehensive CDM position on accepted electric sector baseline methodologies is documented in ACM002. Michael Lazarus, a member of the CDM Methodology Panel, summarized the alternative accepted OM methods as shown in Figure 2.3.

Figure 2-5 CDM Accepted OM Methods



The four OM options can most readily be distinguished graphically in terms of a load duration curve as shown in Figure 2.4.[4] Graphically, the S***imple OM*** analysis would suggest that areas shown as yellow and light brown represent be considered as displaceable energy. The ratio of the gas block (yellow) to the sum of the gas block plus the intermediate coal block (light brown) would provide the percentage of displaced energy that comes from gas fired units. The remainder of displaced energy would come from intermediate coal units. Calculations for this specific example indicate that gas would account for 7.7% and intermediate coal units 92.3% of the total displacement. In this case, the displacement margin is very broadly interpreted to mean all energy production above baseload and must-run generation which is shown as dark brown in the diagram.

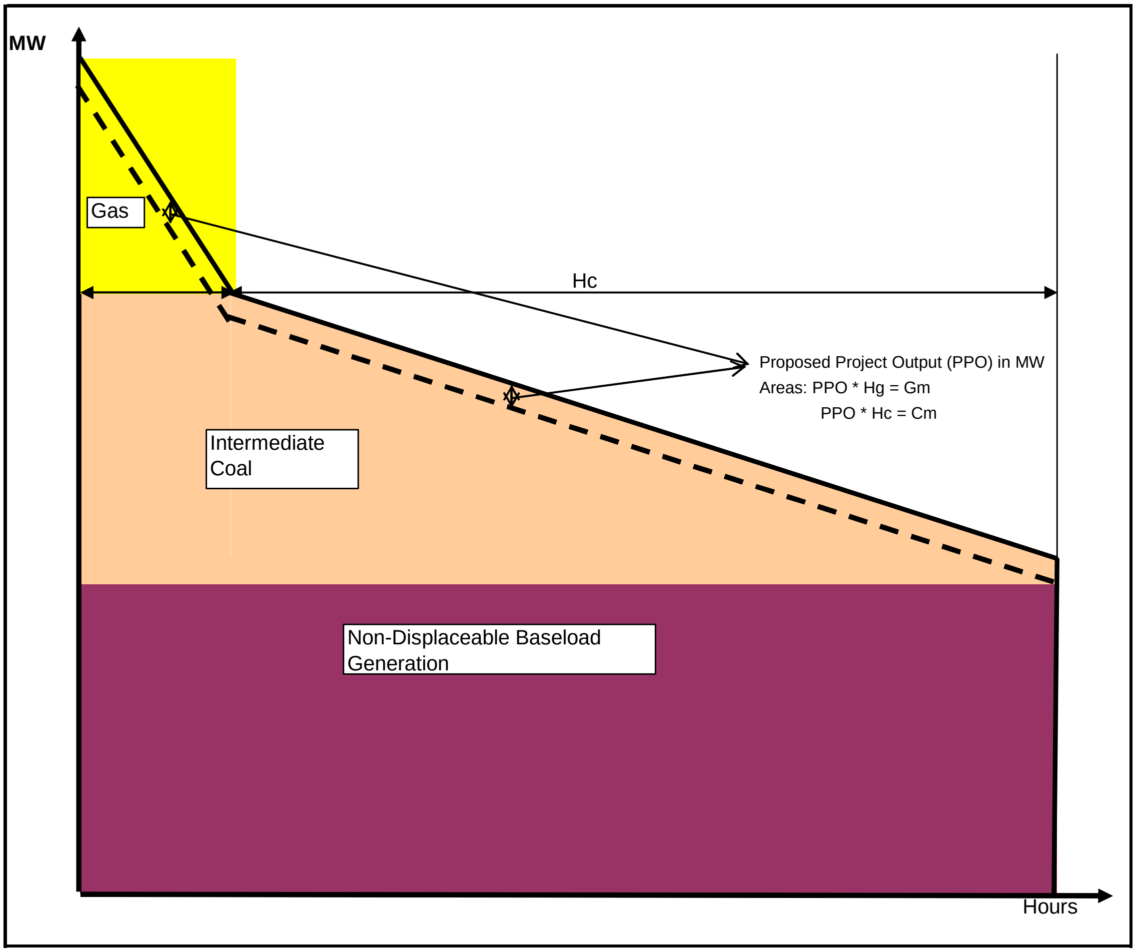
The ***Average OM*** method is even simpler but further separated from the concept of displacing truly marginal generation. In this method, the displacement shares are simply estimated as the percentage share of total generation represented by each type of generation (yellow block is gas, light brown is intermediate coal, and dark brown is assumed to be lignite). In the illustrated case, the displacement mix would be 64.4% lignite, 32.9% coal and just 2.8% gas.

The last approach that can be adequately illustrated in this diagram is ***Dispatch Analysis.*** For a proposed project that produces fixed electrical output for every hour of the period being analyzed, the load dispatcher can specify the specific marginal units that would have operated absent the proposed project. As the graph shows, the displacement areas

[4] The illustration is conceptual only and not drawn precisely to scale.

are the narrow strips with the dashed line as their lower boundary. The gas share of displacement is then calculated as Gm/(Gm + Cm). In this specific illustration, this

Figure 2-6 Illustrative OM Model – Case 1



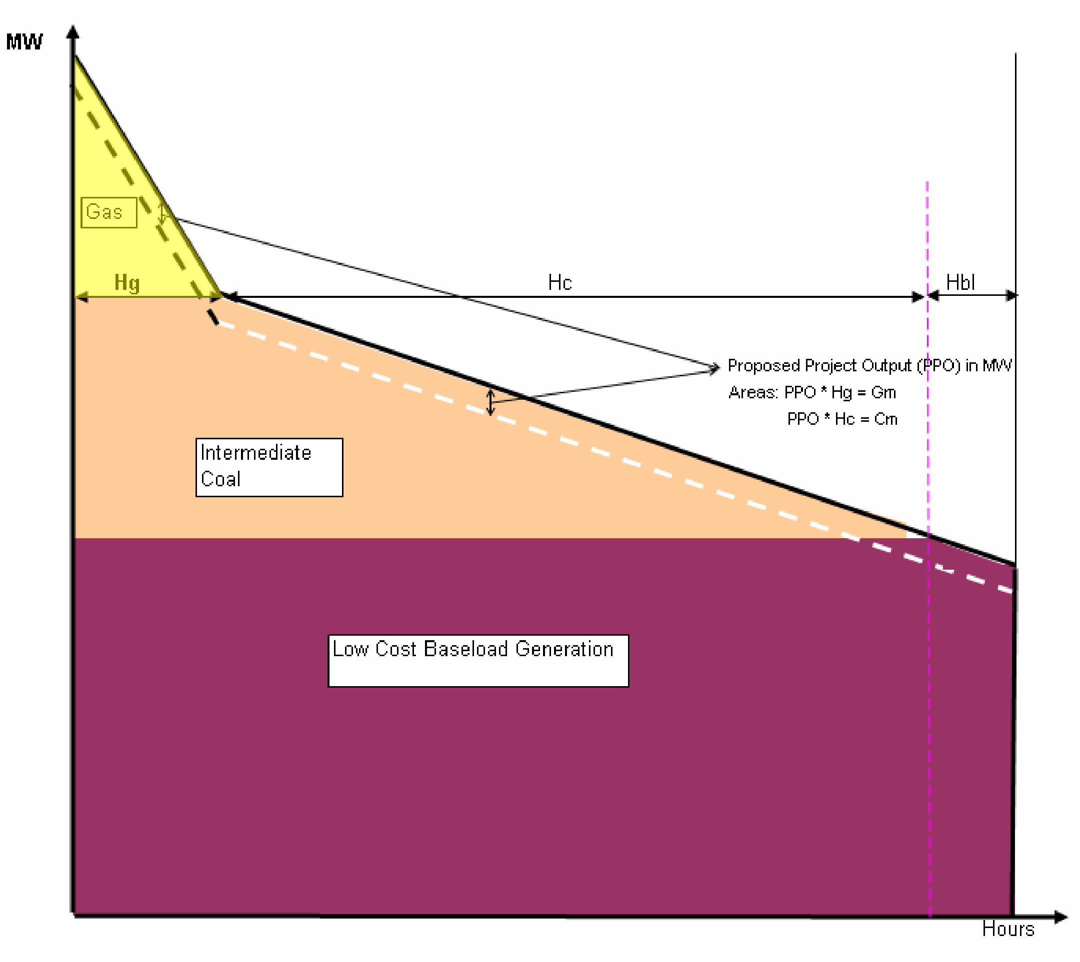
method yields a fuel displacement mix of 11.4% gas and 88.6% intermediate coal.[5] Since the carbon intensity of lignite is greater than that of coal and both coal and lignite intensities are greater than that of gas, this variation in displacement mix estimates will directly impact the estimates of CO2 reductions.

Finally, the ***Simple Adjusted*** method can be more readily demonstrated in the following diagram. The distinguishing feature of this case is that not all of the baseload generation operates for every hour of the year. For this case the CDM methodology calls for recognition of the baseload share of total generation based on the ratio of Hbl over the total hours in the period or 8,760 for an annual analysis. The generation above baseload would continue to be split between coal and gas based on the relative size of the yellow

[5] It is worth noting that for this fixed production regime for the proposed project, the mix of marginal fuels can simply be calculated based on the hours (Hc and Hg) that each fuel is on the margin. Calculations must also reflect the relative efficiencies of the marginal units but the intent here is simply to illustrate the conceptual basis of the alternative methodologies.

and light brown blocks. This would yield a displacement mix of 5.7 % lignite, 85.1% coal and 9.2% gas.

Figure 2-7 Illustrative OM Model – Case 2



Although it has not been included in ACM002, it would seem logical and probably more accurate to consider an **adjusted dispatch** method that would simply divide the three types of generation by the hours that each is on the margin. In the illustration, that would yield a generation mix of 5.7% lignite, 82.9% coal and 11.4% gas.[6]

To summarize, three accepted OM methodologies were compared in the first illustrative case and an accepted OM method was compared with a new variant for the second hypothetical case. The mix of grid displacements for these test cases is summarized in Table 2.1. Given the mix of fuels, the carbon emission factors (CEFs) can easily be calculated in terms of MT of CO2/MWh produced based on the generic parameters reported below in Table 2.3.

[6] This methodology has been applied by the author for a PCF umbrella project in the Czech Republic and was presented at the workshop.

Table 2.1 Alternate OM Fuel Mixes and CEFs

Case	Method	Lignite	Coal	Gas	Total	CEF	CEF CC
One	Simple OM	0.0%	92.3%	7.7%	100.0%	0.94	0.46
	Average OM	64.4%	32.9%	2.8%	100.0%	1.12	0.94
	Dispatch	0.0%	88.6%	11.4%	100.0%	0.93	0.46
Two	Adjusted Simple OM	5.7%	85.1%	9.2%	100.0%	0.95	0.50
	Adjusted Dispatch	5.7%	82.9%	11.4%	100.0%	0.94	0.51

There is little doubt that the dispatch method is the most satisfactory methodology and by extension, the adjusted dispatch method should be preferred for the second case. In fact, ACM002 proclaims that the dispatch method should be the first methodological choice. However, data availability and the cost of using this method may often cause practical limitations on its use. In these cases, the most useful approach may be to retain the underlying concept but to find simplified methods of estimating the hours that each generation type is or will be on the margin.

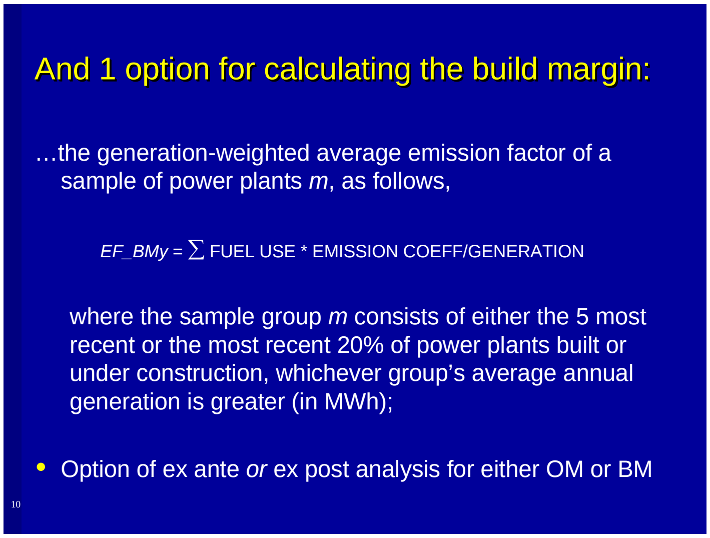
The CEFs provide the most direct indication of the impact of the OM estimation methods on the total carbon reductions that will be allowed for proposed projects. For the two cases examined here, the variation across methods is not significant with the exception of the Average OM approach which clearly overstates the legitimate reductions. It is also evident that all of the methods except the Average OM approach are very sensitive to the plausible substitution of combined cycle gas units for conventional coal units operating in the intermediate range. For the simple OM, for example, the CEF associated with coal-fired intermediate generation is 0.94 MTCO2/MWh. If gas-fired combined cycle units provide marginal intermediate generation, the CEF falls to 0.46 MTCO2/MWh.[7]

[7] If gas prices are low enough relative to lignite so that a gas fired CCs could provide baseload generation, the differences in CEFs would be even larger. For most current price regimes, however, CCs now are most economic for operation in the intermediate range.

2.2.2 Accepted BM Methods

Mr. Lazarus also summarized the ACM002 BM methodology in Figure 2.6.

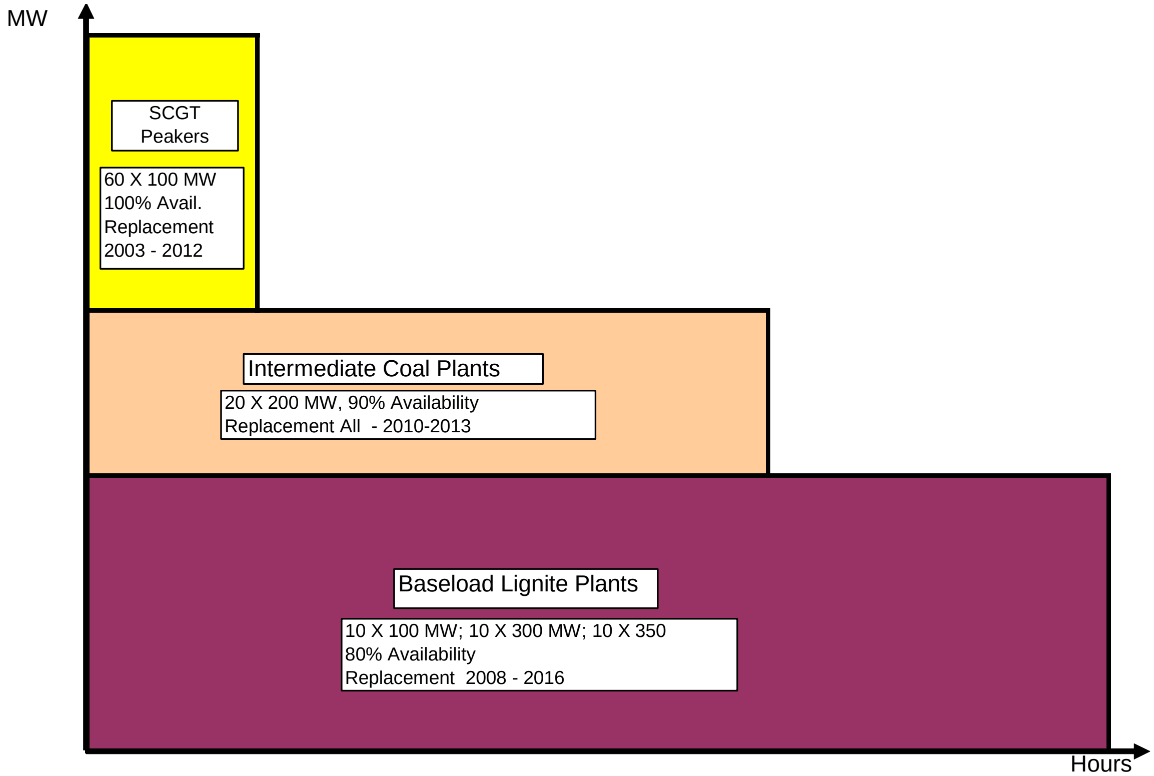
Figure 2-8 CDM BM Summary



It is important to note that the BM is often more difficult to estimate than the OM since it requires speculation on future grid generator additions both with and without the proposed project. While least-cost planning techniques for the industry are well-known, they rely heavily on long-term forecasts of variables such as fuel prices that are notably difficult to forecast accurately. In addition, the regulatory framework for the electric industry and critical energy policies are undergoing substantial revision in many countries. In most cases, any long term forecast of capacity additions to a given electric grid should be viewed as subject to significant, and largely irreducible, uncertainty. This may well be one of the primary reasons that ACM002 relies totally on historic rather than projected capacity additions as the approved method of specifying the build margin.

To more fully illustrate build margin issues, this paper relies on the concept of "transparent hypotheticals" to test various build margin approaches under restrictive sets of assumptions that simplify the solutions to an otherwise complex problem without removing any essential characteristics that would influence the outcome of the analysis. The hypothetical model is graphically portrayed in Figure 2.7.

Figure 2-9 Transparent Hypothetical BM Model



This is a stylized load duration curve for an electric system served by a mix of lignite, coal and gas peaking plants. The existing capacity mix is assumed to generate this load at least cost under current fuel prices and energy efficiencies. The current capacity and energy mix for the system is summarized in Table 2.2.

Table 2.2 BM Model Capacity and Energy Mix

Plant Type	MW @ Peak	Energy	Cap Factor
Lignite	38.5%	63.8%	100.0%
Coal	23.1%	25.5%	66.7%
Gas	38.5%	10.6%	16.7%

Additional generic assumptions used to characterize the illustrative system are present in Table 2.3. The system above includes the coal-fired intermediate unit. An alternate intermediate unit based on a gas-fired combined cycle plant is also shown to support later variants.

Table 2.3 Illustrative Generic System Parameters[8]

Variable	Baseload	Intermediate A	Peaking	Intermediate B
Hours/Year	8,760	5,840	1,460	5,840
Availability	0.8	0.9	1	1
Unit Size 1	100	200	100	200
Unit Size 2	300	200	100	200
Unit Size 3	350	200	100	200
Installed MW	7,500	4,000	6,000	4,000
Effective MW	6,000	3,600	6,000	3,600
Life	25	15	20	15
Net Efficiency	33.0%	33.0%	33.0%	45.0%
Fuel	Lignite	Coal	Gas	Gas
MTCO2/MWh In	0.40	0.32	0.20	0.20
MTCO2/MWh Out	1.21	0.97	0.61	0.44

Looking forward, it is assumed that the load level and shape remains fixed and that fuel prices and also remain fixed. The steady state peak demand is 15,,600 MW and the annual energy requirement is 82,344 MW. Under those circumstances, the optimum mix is not likely to change so that the entire expansion path can be established very simply based solely on the replacement cycle for existing units as summarized in Table 2.3. Units are replaced in kind. We can further assume that baseload units have a 25 year life; peaking units have a 20 year life and intermediate units[9] have a 15 year life. The baseload and peaking plants were built in 1983 through 1992 with the intermediate units added in 1995 and 1998. As of 2004, the most recent plant additions would be peakers. The most recent additions that produce at least 20% of annual energy would be peakers and intermediate units.

[8] Note that coal and lignite carbon content can vary from a low of 0.32 MTCO2/MWh to 0.40 MTCO2/MWh of fuel input depending on the specific fuel source. These factors divided by conversion efficiencies yield carbon emission factors (CEFS) in terms of MTCO2/MWh of electric output. Extreme values have been chosen for the illustration to illustrate the difficulties that can arise in application of the current combined margin methodology.

[9] Intermediate units are often older coal units that require periodic life extension refurbishment at more frequent intervals than the baseload units. More recently, combined cycle gas units have been popular in this role. Merchant versions of these plants may have a life of 15 years.

Table 2.4 BM Model Capacity Additions – 1983 - 2012

Year	Additions Baseload	Intermediate	Peaking	Cum MW	Number of Plant Adds Baseload	Intermediate	Peaking	Total
1983	1,000		1,000	2,000	10	0	10	20
1984				2,000	0	0	0	0
1985				2,000	0	0	0	0
1986				2,000	0	0	0	0
1987	3,000		1,000	6,000	10	0	10	20
1988			1,000	7,000	0	0	10	10
1989			1,000	8,000	0	0	10	10
1990				8,000	0	0	0	0
1991	3,500		1,000	12,500	10	0	10	20
1992			1,000	13,500	0	0	10	10
1993				13,500	0	0	0	0
1994				13,500	0	0	0	0
1995		2,000		15,500	0	10	0	10
1996				15,500	0	0	0	0
1997				15,500	0	0	0	0
1998		2,000		17,500	0	10	0	10
1999				17,500	0	0	0	0
2000				17,500	0	0	0	0
2001				17,500	0	0	0	0
2002				17,500	0	0	0	0
2003			1,000	17,500	0	0	10	10
2004			-	17,500	0	0	0	0
2005			-	17,500	0	0	0	0
2006			-	17,500	0	0	0	0
2007			1,000	17,500	0	0	10	10
2008	1,000		1,000	17,500	10	0	10	20
2009	-		1,000	17,500	0	0	10	10
2010	-	2,000	-	17,500	0	10	0	10
2011	-	-	1,000	17,500	0	0	10	10
2012	3,000	-	1,000	17,500	10	0	10	20

Given this setting we can now illustrate how build margins would be established for various proposed projects. As an initial illustration, consider a proposed 100 MW biomass plant that is designed to operate 7008 hours per year. This is exactly equivalent to the duty cycle of the baseload lignite plants. The proposed project will come on line in 2008. The correct build margin is then clear since the proposed project will exactly displace the 100 MW lignite unit that would have otherwise been built. This is true for 2008 and for all subsequent years over the life of the proposed project and the baseline project that it displaces assuming that both have the same expected life.

It is then useful to compare this transparent solution with the approved ACM002 methods of calculating the build margin. ACM002 provides the following two options for calculation of the BM.

- *Option 1* Calculate on en *ex ante* basis based on existing plant data using the five most recent plant additions at the time of the submittal Project Design Document for the proposed project, or the plant additions that are most recent and that comprise at least 20% of total generation. Of these alternatives, select that which accounts for the most energy. For the illustration, this would be a mix of the peakers plus enough of the intermediate units to get to 20% of total energy.

- <u>*Option 2*</u> Calculate as above but on an *ex post* basis for each year in the first crediting period which runs from 2008 through 2012.

Applicants should choose between these two options to maximize the annual generation represented.

For a PDD filed in 2004, Option 1 would based on the most recent plants that account for 20% of total generation. The 1,000 MW of peakers built in 2003 would generate 1,460 GWh or 1.8% of total energy. The 2,000 MW of intermediate units built in 1998 would produce 10,512 GWh or 12.8% of annual energy. The remaining 5.4% of the 20% would come from intermediate units built in 1995. We could thus calculate a carbon emission factor for the BM as:

$$(1.8/20.0) * 0.61 + (18.2/20.0)*0.97 = 0.94 \text{ MT } CO2/MWh \text{ Out}$$

Under Option 1, this factor would be fixed for the entire 2008-2012 crediting period.

Under Option 2, the same type of analysis would be completed for each year from 2008 through 2012 to obtain the results shown in Table 2.5. The project proponent would apparently choose the Ex Post Option but would still lose 17% of legitimate carbon reductions by application of the most attractive accepted method. The shortfalls are also front-end loaded which would reduce the present value of the carbon fund flow by more than the 17%.

Table 2.5 Alternative BM CEFs (MT CO2/MWh Produced)

Year	Ex Ante	Ex Post	Exact	Ex Post/Exact
2008	0.94	0.98	1.21	81%
2009	0.94	0.94	1.21	78%
2010	0.94	1.00	1.21	83%
2011	0.94	0.90	1.21	74%
2012	0.94	1.21	1.21	100%
Total	4.68	5.03	6.06	83%

This reduction in carbon emissions is significant but not necessarily outside the realm that might be justified by invoking a general preference for conservatism in the estimates. However, Table 2.6 shows that simple substitution of gas-fired combined cycle units for the intermediate coal unit would dramatically increase the ACM002 penalty to one third of total benefits based solely on the BM analysis.

Table 2.6 BM CEFs For Combined Cycle Gas Intermediate Units

Year	Ex Ante	Ex Post	Exact	Ex Post/Exact
2008	0.46	0.81	1.21	67%
2009	0.46	0.83	1.21	68%
2010	0.46	0.67	1.21	55%
2011	0.46	0.56	1.21	46%
2012	0.46	1.21	1.21	100%
Total	2.29	4.08	6.06	67%

2.2.3 Consolidated Method

Following presentation of approved OM and BM baseline methodologies, AC002 codifies the combined margin approach which calls for the use of a weighted average of the OM and BM methods with equal weights as the default. Alternative weights can be proposed but would be subject to approval by the Executive Board. Thus, the only pre-approved weights that can be applied without uncertainty and delay are equal weights.

It is instructive to continue the transparent hypothetical case through the calculation of the combined margin CEFs. Assuming that the OM can be calculated most accurately using the Adjusted Dispatch method[10] based on the hours that each type of unit is on the margin, the OM CEFs can be calculated as shown in Table 2.7 for two different assumptions regarding the types of units used for intermediate duty.

Table 2.7 OM CEFs For Coal and CC Gas Intermediate Units

Fuel/Technology	Marg Hours	Percent	CEF
Gas Peakers	1,460	16.7%	0.61
Coal Intermediate	4,380	50.0%	0.97
Lignite Baseload	2,920	33.3%	1.21
Total	8,760	100.0%	0.99
Gas Peakers	1,460	16.7%	0.61
CC Gas Interm.	4,380	50.0%	0.44
Lignite Baseload	2,920	33.3%	1.21
Total	8,760	100.0%	0.73

Combining these results with the BM CEFs from the previous section, yields the CEFs shown in Table 2.8.

Table 2.8 Combined Margin CEFs for Coal and Gas CC Intermediate Units

Intermediate Coal					
Year	OM CEF	BM CEF	Comb CEF	Exact CEF	Percent
2008	0.99	0.98	0.98	1.21	81%
2009	0.99	0.94	0.97	1.21	80%
2010	0.99	1.00	1.00	1.21	82%
2011	0.99	0.90	0.94	1.21	78%
2012	0.99	1.21	1.10	1.21	91%
Total	4.95	5.03	4.99	6.06	82%
Intermediate CC Gas					
2008	0.73	0.81	0.77	1.21	64%
2009	0.73	0.83	0.78	1.21	64%
2010	0.73	0.67	0.70	1.21	58%
2011	0.73	0.56	0.64	1.21	53%
2012	0.73	1.21	0.97	1.21	80%
Total	3.64	4.08	3.86	6.06	64%

[10] Note that this method is not officially approved in ACM002 but it is a logical extension of Adjusted OM method and can be shown to be more accurate.

For this specific case the combined margin approach defined in ACM002 would understate the true reductions by 18% to 36% depending on the fuel and efficiency of the intermediate units. More extreme reductions would also be possible if the baseload resources in the system were predominantly nuclear or hydro. Discrepancies would be reduced if the coal and carbon intensities were closer than those assumed for the illustration. Even if 100% weighting of the BM were accepted, the ACM002 gap would remain between 17% and 33% compared to the actual reductions that would be achieved.

2.2.4 ACM002 Testing For Colombia Project

While the transparent hypothetical case above has attempted to represent a plausible real system without extreme peculiarities, there could be inadvertent assumptions that lead to misleading results. It is therefore, useful to consider the calculation of various OM, BM, and CM CEFs for specific projects that have sufficient data to allow thorough testing. Variation in estimates is not cause for concern as long as the reasons for such variation are transparent and a reasoned case can be made for use of a particular estimate. The primary value of this kind of analysis is to test the plausibility of ACM002 methods across different settings and to isolate the unique features of systems for which these methods do not appear to yield appropriate results.

Walter Vergara of the World Bank provided additional useful comparisons of ACM002 methods for a project in Colombia. The range of results obtained from several credible approaches for this case is summarized in Figure 2.8 juxtaposed with the estimates that result from application of ACM002. While the OM, BM and CM all vary by a factor of nearly 2.0 across the range of methods considered, the lowest estimate in every case is dramatically higher than the ACM002 result. These results merit further analysis to explain the particular features of this power system that dictate such apparently extreme ACM002 results.

Figure 2-10 ACM002 CEFs for Colombia Project

Colombia CEFs in tCO_2/MWh				
	Range		ACM0002	ACM0002
Item	Low	High	Estimate	% of Mean
Operating Margin	0.450	0.849	0.116	17.9%
Build Margin	0.452	0.86	0.023	3.5%
Combined Margin	0.451	0.855	0.069	10.6%

2.2.5 Summary of the CDM Response

The most general and comprehensive guidance on electric sector baselines that has been provided so far by the CDM Methodology Panel is codified in ACM002. The key contributions of ACM002 have been to distinguish the OM and the BM as key elements in determining the appropriate baseline. Useful flexibility has been built into the methodology to accommodate different possible data availability situations in different power markets. Attempts have been made to define the BM in terms of observed plant additions based either on the period prior to submittal of the PDD or based on annual monitoring during the 2008 – 2012 period. However, the hypothetical case developed above illustrates certain circumstances under which the ACM002 methods would lead to serious underestimation of the legitimate carbon reductions from a proposed project. The Colombia case suggests even more severe distortion under certain circumstances. The Panel does continue to encourage new methodologies[11] to be submitted for consideration for specific projects but this will not remove the dampening effect of the so called "CDM Risk" as long as reaction times from the Panel remain unknown and possibly lengthy. Coupled with the tightening time frame for electric sector projects that can claim carbon benefits over the full 2008 – 2012 crediting period, the under-representation of electric projects in the CDM portfolio may be destined to continue.

2.3 Key Open Issues

Previous sections have focused on quantitative comparisons of the core approved baseline methodologies for electric generation projects. While these topics were a central focus of the workshop, there were many excellent presentations that raised a variety of related issues. This section documents some of the key issues that were raised that circumscribe any set of new methodological developments.

2.3.1 Standardization Vs Proliferation

The regulatory role of the CDM Methodology Panel and Executive Board with respect to the approval of baseline methodologies was established at Marrakesh. The process is a bottom up, reactive approach in which specific project baselines are defined as part of the PDDs for individual projects. The Panel and Board then approve or disapprove of the proposed methods on an individual basis. ACM002 is an attempt to generalize the experience gained from a collection of eight proposed new methodologies. This raises the natural but unanswered question of how many specific cases are enough to provide the needed ex ante guidance that will apply reasonably to a high percentage of likely project cases.

The approach that has been used in the Czech Republic to deal with multiple small projects under an umbrella purchase agreement is to develop a standardized electric sector baseline that can be used for a clearly defined class of projects. Pre-approval of the standardized baseline will provide potential project developers with the ability to project carbon credits with the certainty that they need to arrange financing and to make investment decisions. The standardized baseline has also been designed to minimize the transactions costs for project preparation and monitoring. At the same time, the project developer is allowed to propose an alternative methodology if they feel that the standard approach discriminates unreasonably against their project. However, the alternative baseline would then be subject to separate validation with uncertain consequences.

[11] Michael Lazarus concluded his presentation with a fertile list of topics that merit further development and an open acknowledgement that there is considerable room for expansion and improvement of the consolidated methodology. See Figure 2-4 above.

If allowed, this approach might enable the CDM Panel to focus on simple but conservative methods that cover defined classes of projects and thus to compress the timeline for providing broadly applicable guidance to larger pools of projects. Conceptually, the historic approach has been driven by "bottom up" or inductive logic. It may now be the time to move toward "top down" or deductive analyses that provide rules on how to solve common baseline problems without waiting for project proposals that pose the question in a particular set of conditions. The concept of a transparent hypothetical model that has been introduced in this paper is designed for exactly this purpose. Many baseline questions can be answered within the confines of that type of model. The result could be substantial acceleration in the construction of a broader base of regulatory guidance.

Einar Telnes of Det Norske Veritas (DNV) moderated a panel of experts in the closing session of the workshop. He also proposed migration away from exclusive focus on individual projects and a move toward establishment of Principles and Standards by which baseline methods will be evaluated. The idea of creating a defined framework rather than specific recipes for electric sector baselines is appealing. While CDM will need to always retain the right to refuse unreasonable claims, this approach could narrow the range of debate, increase the proportion of acceptable proposals, and accelerate the processing of applications.

2.3.2 Modeling Issues

The electric utility industry is one of the most capital intensive industries in the world and in most countries and often accounts for a notable percentage of financing requirements even in advanced economies. At the same time, the end product is widely viewed as a social necessity which has given rise to a history of active public intervention in the regulation of this sector and to wide availability of rather detailed sector data in most countries. More recently, however, the global trend is toward separating generation from transmission and distribution functions and allowing increased competition in the construction and operation of new power plants.

The optimal operation of modern integrated power grids is a complex business. This complexity coupled with extremely large investments for new capacity has led to the development of many simulation tools to guide investment and manage the operation of evolving systems. Economic evaluation of the sector requires the capability to identify least cost expansion paths including periodic decisions on the types of plants to retire and to add and real time decisions on how to operate the portfolio of generating resources at any given point in time.

The problem in attempting to require modeling the foundation for sector baselines is not the lack of available models but rather the proliferation of models. There are several generations of models each designed for specific kinds of systems. Taxonomies can be developed along several dimensions:

- <u>Time Horizons</u> – Capacity expansion models typically offer annual or monthly time resolution and need to be run over periods of 10 to 20 years to fully test alternative expansion paths. At the other extreme are very short term unit commitment models that optimize the use of generation over the next day. The Midwest Independent System Operator (MISO) has just begun operation and is using a very detailed model that takes six hours to run. This model will be run daily to establish locational marginal prices throughout the upper Midwest. RTSIM provides year ahead optimal scheduling of maintenance of units for any set of hourly prices.

- <u>Unit Dispatch Logic</u> – Models for systems dominated by fossil-fired units often dispatch loads against a load duration curve. However, load duration curves do not retain information on the sequence of the hourly loads. That information is important for hydro-dominated systems with significant reservoir storage.
- <u>Transmission Constraints</u> – Simple models treat major transmission nodes as flowgates with certain capacities. More complex models include load flow calculations that determine transmission flows at each time interval based on the complete generation plan and loads at every node on the system.
- <u>Market Structure</u> – Central economic dispatch of all units has been common in fully regulated markets. New market designs include bidding in day ahead hourly markets. Experience has shown that units can and will be run very differently in response to different price patterns that occur in fully competitive markets. Models also vary in their representations of bidding behaviors vs centralized dispatch.

These are just a few examples to show the large number and wide range of models that are currently available and in use. Several decades ago, there was some convergence in international power sector modeling based on the WASP model but there is no longer a dominant tool in the market.

In my opinion, sophisticated modeling does not offer a promising solution to the challenges of establishing near term rules of general applicability for the construction of electric sector baselines. That belief is based on the following observations:

1. There is no model that offers a "silver bullet" solution that would readily provide consensus optimal solutions. Modeling is an art not a science and the models are only as good as the modelers. It is easy to improve on the optimal capacity expansion paths that result from models with this capability by simply changing the size of the unit additions that are allowed. Ultimately, the model results will reflect the insights of the analyst rather than any easily controlled set of calculations.
2. Models operate on an all or nothing basis with respect to the data inputs that are required. If all inputs are not available, no results are available. This is particularly critical since data that were once readily available through required regulatory reporting are now disappearing as increasingly competitive power suppliers choose to protect critical data such as unit heat rates as trade secret information.
3. The effort needed to accurately model sizeable power systems is well beyond the level of affordable transactions costs for many of the projects that might be proposed to CDM. A power supply study to support investment in a significant

generation plant can easily cost more than $100,000 which would price it out of the market for many individual carbon reduction projects.

4. In most cases, models are designed to provide far more information than is really required for baseline purposes. Relatively simple calculations can create persuasive evidence regarding the appropriate baselines to use for specific projects.
5. Our consulting experience has been that most clients that want model based solutions already have the relevant system modeled using the tool of their choice. There is then no possibility of proposing an additional modeling effort using a different tool. Therefore, I would not see much opportunity to mandate a particular model for general baseline construction.

2.3.3 Economic Evaluation Methodology

In the determination of the OM, a very common approach is to assume economic dispatch of units which dictates that the available units with the lowest variable costs are fully utilized before more expensive units are brought on line.[12] Units are scheduled for operation by a central dispatcher who has access to the dispatch cost and availability for each unit in the system on a real time basis. Units are thus scheduled under the load curve in a way that provides the power demands for that period at minimum cost from the given set of generators. By far the dominant factors in these calculations are the delivered fuel costs to each generator and the heat rates or efficiencies of each unit. Stephen Wilson of ECA provided interesting contrasts of the Chinese and Indian power markets. His comparisons of the all-in costs for new coal and gas generators show gas as less costly in India and coal as less costly in China. This is because India heavily subsidizes gas relative to coal at this time. The assumptions used vis a vis future subsidization of gas in India will influence both the OM and the BM. There is no useful general guidance that can be provided in this case on what to assume. Pure economic analysis would remove such distortions from the analysis. Pure financial analysis must be based on whatever the most probable case appears to be at the time that the PDD is completed. If results must be based on a forecast, there is really no alternative to making the most persuasive case that is possible given what can be known about future Indian energy policy. The more satisfactory approach may be to work out the OM and the BM for both the subsidized and non-subsidized case and then just apply the appropriate CEFs in each year based on monitoring of what really happens.

The second major dilemma in economic evaluations relates to the assumptions used in assessing the investment alternatives going forward. The economic justification analysis of a power plant can vary significantly between public and private investors since private investors will require a much higher rate of return. Thus public investment may be more likely to favor baseload units that tend to cost much more per kW. In the US, deregulation of wholesale markets led to a substantial move toward lower cost combined cycle units financed by merchant investors. Again there is no universal answer to this question but it is clear that the market structure that is expected to surround future

[12] This process is called economic dispatch. While there are exceptions for must run units and for voltage regulation, rank-ordering by total variable cost is the dominant principle.

investment decisions should be specified in the baseline study and that future changes in that structure should be considered as part of the required monitoring effort if changes are anticipated.

2.3.4 Changing Market Size Issues

Both the OM and the BM can only be meaningfully defined in the context of a particular power market. To establish the OM, we must be able to specify the number of hours that specific fuel-technology pairs are operating on the margin. To do that, we would ideally need to indicate that total load and total portfolio of generators that is being dispatched to meet that load. Similarly, for the build margin, we would like to know the size of the relevant market for new load and new generation.

Historically, many power market boundaries could be adequately approximated by country borders since each country built and operated its own system on an independent basis. Cross-border exchanges were not uncommon but were typically a relatively small part of the total market. However, the drive toward more competitive generation market structures is now pushing toward liberalized markets in many areas. When power markets become multinational, the complexity of forecasting future market generation and construction mixes can increase dramatically. National energy policies and permitting procedures for new generation can differ widely. Data availability can also vary widely by country. While the same modeling approaches would apply to both national and multinational power markets, the practical implications for baseline preparation could be substantial.[13]

Despite the expansions of potential power markets, this problem may be limited for countries that are likely to remain net exporters of power for the relevant future period. In this case, the load curve that should be considered includes native load plus net exports. Generation of domestic resources is dispatched and planned against that load curve. This is the solution that has been used in the standardized baseline study for the Czech Republic. Further studies are being conducted to determine the importance of hourly net export data in construction of the load curve compared to simpler representations that have been used in the standardized baseline.

It is also useful to note that markets may be liberalized but the extent to which cross-border trade can take place is often limited by transmission constraints since transmissions systems were seldom built to accommodate unfettered flows among many countries. In such cases, the effective limitations to trade should be indicated.

[13] Stephen Wilson provided additional examples of changing market size in China where several independent grid operations are moving toward integrated operation. Although each area may be governed by a common national policy, this will also require expanded data gathering and analysis to address the combined system markets.

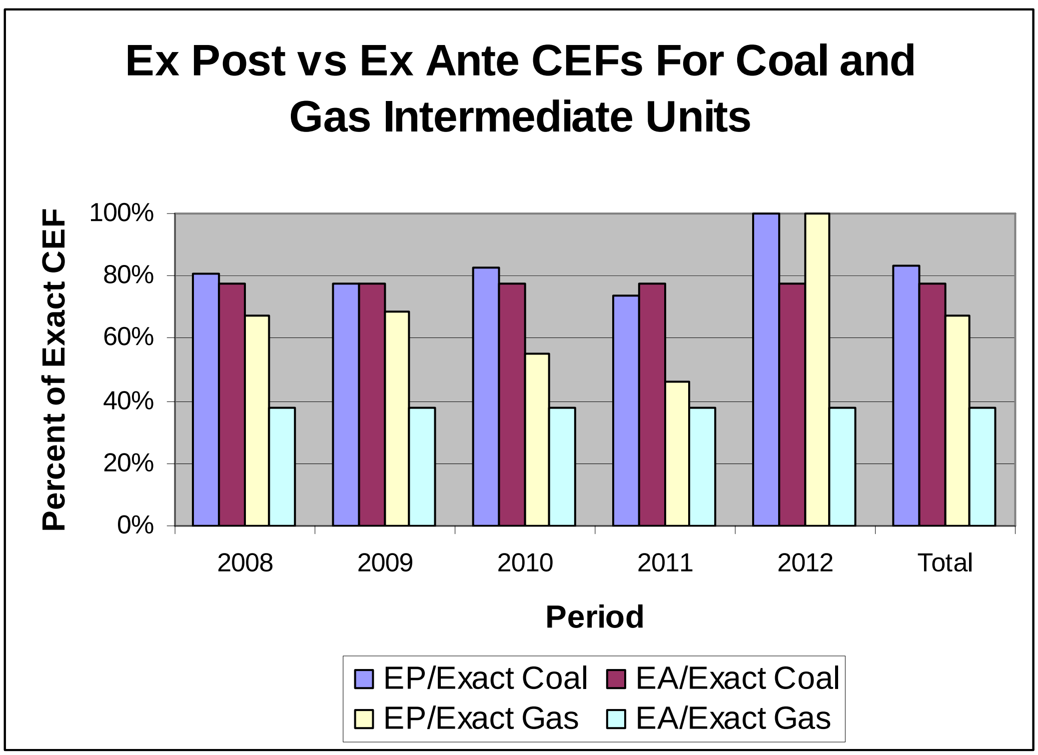
2.3.5 Historic vs Forecast System Data

The choice between the use of observed historic data or of forecast data to support calculation of OM, BM and CM CEFs is both important and difficult. ACM002 currently allows for the use of ex ante or ex post analysis for either or both of the OM and BM analyses. Specifically, the data vintages that can be used for the OM are:

- A three-year average based on the most recent data available at the time of PDD submission.
- Year by year ex post analysis based on the ongoing monitoring.

For the BM, similar choices are available although the relevant history is defined in terms of the five most recent plants or the most recent plants that represent 20% of system generation. The transparent hypothetical cases reported in Tables 2.5 and 2.6 demonstrated the possible impacts of the choice of data vintage choices for the BM. Those results are repeated in graphic format in Figure 2-9. With coal as the intermediate fuel and lignite as the baseload fuel, the ex post and ex ante results do not differ excessively. However, with gas combined cycle units providing intermediate generation both fuels and efficiencies change and the impacts of ex post versus ex ante analysis is extreme.

Figure 2-11 Ex Post Vs Ex Ante CEFs



Even absent quantitative demonstrations, the theory of BMs based on ex post observation is problematic. The appropriate focus is forward looking and based on the available information at the time that decisions are made on future generating units that are the logical candidates for displacement by the proposed project. There are long lead times for new generating units that should be recognized. For example, in the case of a large biomass unit that is intended to operate 7,000 hours per year and to come on line in 2009 we might reasonably expect that this would displace a coal-fired unit of similar size and timing. Lead times for a new coal unit may range from three to five years. Thus, final decisions on the coal unit would be made in 2004 to 2006 based on information available at that time. If we were to begin monitoring at the end of 2009 for the biomass unit, we might look at years 2008 and 2009 and find at that time new baseload capacity is being supplied by combined cycle gas units because of changes in relative fuel prices or emission regulations. This is simply not relevant to the BM for this proposed project. The unit that would have been built in lieu of the proposed project would be the coal unit that would have been committed in 2006. As a result of the proposed project, the coal unit would not be built. What happens subsequently is not relevant.

In contrast to this forward looking approach to the BM, the OM can and should be based on annual ex post analysis of operating data for the system in question. For the BM, the proposed project will be tied to a specific new unit or a few units of a specific type. By contrast, very few CDM projects are likely to have a major impact on the total amount of generation in the system from each of the major fuel-technology groups. Thus, ex post observation of the fuel mix will be largely unperturbed by the proposed project and provide a good proxy for what would have been observed without the project. Since the year to year generation mix could change significantly in response to fuel price changes and since fuel prices cannot be forecast very accurately, the best approach is to monitor the generation mix and incorporate that information into a dynamic OM analysis.

2.3.6 New OM and BM Methodologies

For complex topics like electric grid baselines, it is much easier to be critical of early attempts to define general approaches than it is propose new methods that are not also subject to such criticism. The workshop reflected this with far more commentary on the inadequacy of ACM002 as a universal guide than there was on alternative approaches that would work better for a wider set of possible projects. An OM and a BM approach were presented that differ from the literal dictates of ACM002. These approaches are briefly summarized here.

The OM approach has already been developed in this paper and labeled as the **adjusted dispatch** method in Table 2.1. ACM002 has already accepted the notion of determining the number of hours that baseload generation is on the margin as a guide to OM calculation. Conceptually, there should then be no problem in extending this methodology to each major type of generation and using the marginal hours as the basis for estimating the marginal fuel mix. This is especially true since this method will be uniformly more conservative than the methods that have already been accepted. If the marginal hour allocation is accepted in principle, there are only two remaining practical questions to be resolved in making this approach broadly operational.

The first issue is how to estimate what fuel-technology pair is on the margin for different hours of the year. Fernando Cubillos of CFB presented a methodology that has been used for analysis of hydro projects in Chile where the baseline analysts were able to gain ongoing access to hourly dispatch data. With that level of information, the only challenge comes from the effort needed to monitor the project but there is little uncertainty in identifying the ongoing marginal mix in a very accurate way. This level of data accessibility is, however, neither typical nor inexpensive to maintain. CDM can expect a broad class of projects that will need simpler and more uniformly practical approaches based on less data than this. I presented some alternative methods that have been tested in the Czech Republic that require more limited data but that will still yield very reasonable results for that system. The marginal hourly split among generation types can be estimated on annual, monthly or seasonal bases following the Czech baseline approaches.

The second issue is the granularity of the fuel-technology taxonomy to be used in dividing period hours into different classes of generation. In theory the most detailed possible categorization would be down to individual generating units or even further if part load versus full load heat rates were recognized. Plant level resolution may be possible if full dispatch data is available. For cases where such data cannot or will not be maintained, reasonable classes can be distinguished based on fuel and efficiency classifications. The major technologies will often be simple cycle gas turbines, combined cycle units running on gas or fuel oil and steam plants fueled by coal or lignite. Efficiencies may or may not be distinguished by plant vintage based on the importance of the distinctions and on the availability of plant specific heat rates.[14] Certainly, the most accurate, readily available data should be used but the use of average efficiencies for each major class of plant should be reasonably accurate and generally feasible. Once the fuel-technology pairs and the marginal hours for each are properly estimated, the remaining variation in plausible efficiencies will be relatively small. Comparison of the incremental costs and benefits of attempting to move beyond this level of detail would seem to suggest that requiring data for individual power plants would not be justified.

My presentation at the workshop included a modest proposal for a new BM methodology that is comprised of the following steps:

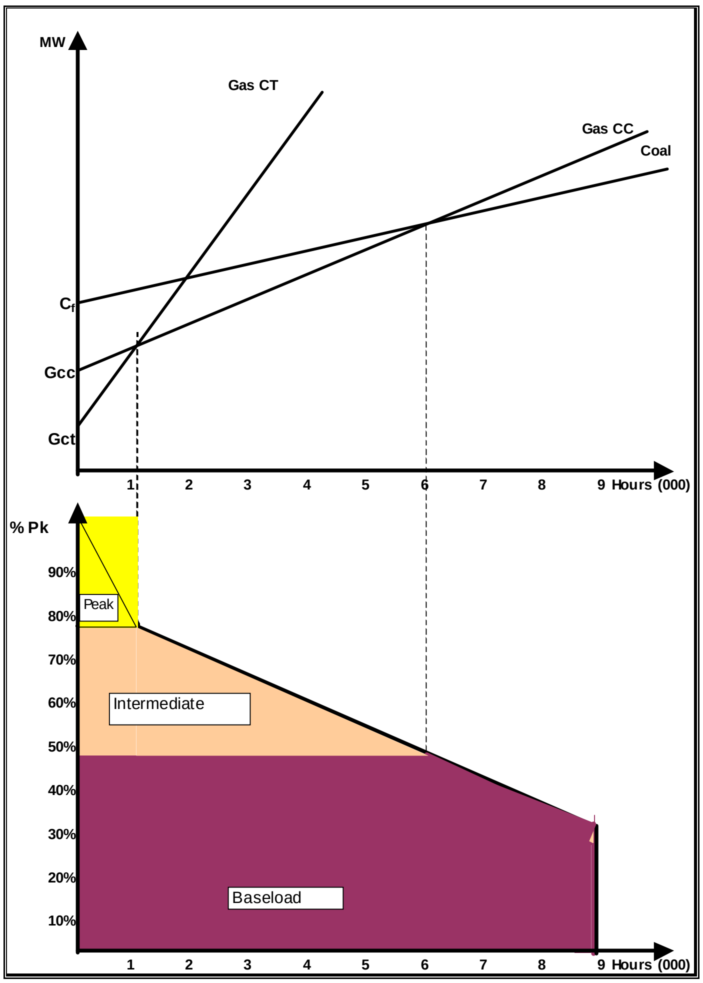
1. A load and capability analysis covering the next 10 years to determine whether load growth is likely to require any capacity additions. If existing capacity less expected retirements is sufficient to cover forecast loads plus reserves, other causes of capacity additions should be considered. The upshot of this task will be to determine the timing and the total MW of likely capacity additions over the next decade. If there are no significant capacity additions anticipated, the BM

[14] It should be noted that plant specific heat rate data is one of the first items to disappear from required reporting when competitive generation markets are established because this data coupled with fuel prices forms the core of competitors strategy development and is thus treated as a trade secret. In the US, such utilities with assured rates of return had no problem in reporting such data but merchant plant operators will not provide this kind of information.

would become irrelevant and only the OM need be considered for that period of time.

2. If capacity expansion studies are not available to identify the least cost mix of capacity additions, compare optimum capacity mix with existing capacity mix in each future year when capacity additions are anticipated using a screening curve analysis similar to that shown in Figure 2-10. The intent is to establish the most plausible future year for the next capacity addition of each functional type (baseload, intermediate, peaking)

Figure 2-12 Screening Curve Analysis



3. For each type of capacity, provide cost comparisons to show which fuel-technology pair is likely to provide the lowest cost alternative. For systems that are dominated by fossil-fired units, this analysis is likely to focus on whether gas combined cycles or new coal units are the most attractive option for intermediate duty. There could also be comparisons of coal vs. lignite for the baseload.
4. Establish the expected operating (or ex post actual) periods and production for the proposed project in terms of baseload, intermediate or peaking categories based

its full load equivalent (FLE) hours.[15] The division into categories can be based on the screening curves above or on pre-established typical figures such as:

- Baseload: 6,000 FLE hours per year
- Intermediate: 1,500 – 6000 FLE hours per year
- Peaking Less than 1,500 hours per year

5. Determine the capacity displacement of the proposed project. Any unit with 6,000 or more FLE hours per year would displace baseload capacity. Peaking and intermediate units, however, require additional analysis to synchronize proposed project production with the timing of the peak and intermediate periods. This can be easily illustrated in the hypothetical model shown in Figure 2-11. The top panel in the figure shows a simplified load duration curve for a winter peaking system in which loads are the same for every hour in each month and each month is 730 hours long. Possible production schedules for the proposed project are shown in the bottom panel. We can then draw the following conclusions for this highly simplified case:
   - A proposed project that produces only in December and January would displace peaking capacity.
   - Units with any of the six production schedules shown in tan would displace intermediate capacity.
   - A unit that produced only in February through May, for example, would not displace peaking, intermediate or baseload capacity and would be considered an energy-only generator. In that case, the BM would not be relevant and only the OM would need to be considered.[16]

6. Develop with and without proposed project capacity expansion paths on a year by year basis over the next decade to establish the impact of the project on new generation capacity.

This BM approach can be developed in a transparent way using data that should be available from reliable sources for most electric grid systems or from reputable international sources. The most difficult data to obtain may be the delivered fuel costs for each type of generator.

Sebastian Bernstein of Synex presented analyses of the build margin for Chile that are similar in concept to the method outlined here. However, the additional detail in the methodology would lead to differences in some circumstances. For example, we would both argue for 100% weighting of the build margin in the case where the proposed

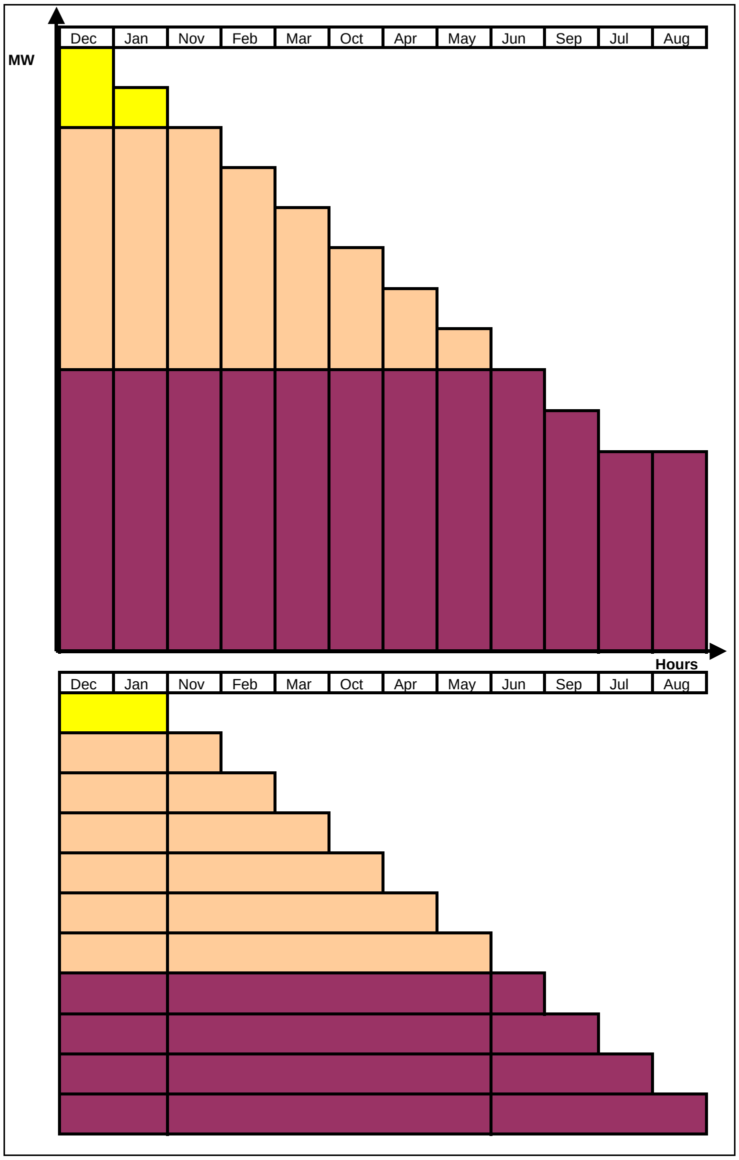
[15] Full load equivalent hours equal the MWh of production divided by the installed capacity of the proposed project. This adjusts for part load operation and all scheduled and forced outages.
[16] Note that the OM analysis in this case should be monthly since the marginal fuel mix differs significantly across the months. In December and January, peakers would be on the margin 100% of the time. In June through September, baseload units would be on the margin 100% of the time. This kind of OM analysis can be developed based on one to three years of historic hourly load data as shown in the Czech standard baseline study.

project provides a perfect substitute for a future unit in terms of duty cycle, size, and timing. In general, he would find very limited applicability of the OM in expanding systems with regular capacity additions. The method proposed here would demands a more complete demonstration of the specific capacity displacement potential for the proposed project before dismissing the OM as irrelevant for selected years.

2.3.7 Appropriate BM and OM Weighting

ACM002 dictates that equal weighting of the BM and the OM is the default option and that any other choice of weights would be considered but would be subject to approval by the CDM Executive Board. The rationale for 50-50 weighting is not clear. In many, if not most, cases a mix of OM and BM would only be appropriate over a multi-year time period. For any given year, the weights should be 100% and 0% for the two margins. This paper has shown a transparent hypothetical case in which a biomass project is an exact substitute for a new baseload lignite generator of the same size, timing and duty cycle. In that case, the BM should be given 100% weight for all years in which the proposed project would operate. A proposed project that would generate only in January through April for the system shown in Figure 2-11 would not eliminate any future capacity additions. In that case, the OM should receive 100% weighting. In the case of the Czech Republic, a 2,000 MW nuclear unit was recently completed and no significant new capacity will be needed until 2010 or beyond. That is another case in which the BM should get zero weight and the OM 100% weight.

Figure 2-13 Load Curve and Proposed Project Duty Cycles



3.0 The Way Forward

This paper has not provided a comprehensive summary of the excellent presentations and discussion that comprised this workshop. Rather, the paper has attempted to focus on key methodological issues and to provide substantive discussion that illustrate both the need for further development and some approaches that may help to accelerate consideration and resolution of key issues. This concluding section concentrates on the future and offers a summary of workshop conclusions and some recommendations for the future CDM regulatory agenda.

3.1 Conclusions From This Workshop

While the workshop did attempt to establish consensus on the issues raised, the following conclusions offer one perspective on the most significant results.

1. CDM faces a daunting challenge in attempting to balance the environmental integrity against transactions costs in establishing broadly applicable methodology for electric sector baselines.

2. Electric grid systems are complex and vary widely. Comprehensive guidance that can cover all cases will require substantial expansion in the body of applicable case studies and in the issues addressed in the approved methodologies.

3. The most advanced CDM guidance, codified in ACM002, may yield unrealistic estimates of CEFs under certain circumstances. Several presentations provided examples of such circumstances.

4. The present CDM regulatory structure dictates a reactive approach to in which the CDM Methodology Panel and Executive Board respond to proposed methodologies.

5. CDM Review and approval times have been unpredictable and lengthy with a chilling effect on developer's interest in electric sector projects with complex baselines and relatively high risk in establishing the role that carbon may play in financing these projects.

6. The time window for carbon reductions to have significant impact on electric sector projects based on payments to be received in 2008 – 2012 is narrowing rapidly due to typically long lead times for these kinds of projects.

7. Although no formal CDM Panel position could be expressed at the workshop, the comments of Panel members suggest that the need for accelerated and expanded guidance is recognized. The Panel labors under severe resource limitations and within an established regulatory structure that makes it difficult to be more responsive to perceived needs.

8. Remarkably, this workshop has provided the first focused forum to bring project proponents, carbon investors, baseline experts, and CDM regulators together to freely discuss the issues of critical interest to all. Expanded communication between the concerned parties would be beneficial to all.

9. This paper has found that the OM methodologies in ACM002 tend to converge and to provide better estimates of correct CEFs than the BM methodologies.

10. This paper concludes that improved BM methodologies and revised guidance on the weighting of BM and OM CEFs are areas offering significant room for improvement in the existing guidance.

3.2 Research Strategies And Specific Needs

This paper offers a number of suggested strategies intended to accelerate the formulation of more widely applicable and predictable methodologies to govern electric sector baseline studies. Both strategies and the early topics on the research agenda are addressed in this section.

3.2.1 New Research Strategies

CDM efforts to have moved from an early concentration on the legitimacy of baseline methods applied to individual specific projects toward development of a body of theory and practice that is intended for more general application. While this is a natural and welcome progression, it should be leveraged more fully and rapidly through the following strategies:

1. Place increased emphasis on baseline frameworks and on the establishment of principles and standards by which baselines will be judged. The specificity of previous guidance may have limited the breadth of its appropriate application.
2. Supplement the historic inductive approaches that attempt to establish principles from reactive responses to large numbers of case studies with deductive approaches that deduce solutions to critical issues from carefully chosen hypothetical conditions. The concept of the “transparent hypothetical” model has been introduced in this paper to provide an example of how this approach can work. The obvious benefits from this supplemental effort would be compression of the time required to generate the guidance that is needed to avoid lost opportunities for carbon reductions in the key electric sector.
3. Shift the emphasis of the CDM Methodology Panel from “hands on” development of detailed guidelines to increase the use of contract research to resolve issues of broad relevance. Funding can most likely be raised if the Panel would participate in the development of the terms of reference for such studies and would commit to downstream responses to the recommendations made in such efforts.
4. Increased emphasis on application of current and future approved methodologies to multiple project settings to reveal the variability of findings and to define limiting conditions under which specific methods yield reasonable results.

5. Development of a best practice casebook.
6. Development of a guidebook that summarizes data needs and identifies data sources that have and can be used to develop electric grid baselines.
7. Evaluation of the potential error exposure in terms of size and direction associated with various methodologies. This could usefully lead to simplified methods that have sufficiently conservative biases to assure the integrity of emission reductions claimed. Project proponents would then have an attractive opportunity to choose between more elaborate baseline efforts with possibly larger reductions or simpler and quicker methods that may yield less carbon credits.
8. The dialogue that began in this workshop was welcomed by all in the carbon community and established a common interest in improved CDM regulatory processes. Increased emphasis on collaborative processes and an established schedule for convening future forums to discuss current and future issues would be most useful.

3.2.2 Topics Of Immediate Interest

Beyond the more general shifts in strategic direction, this paper has created several hypothetical models that could be usefully extended to answer a range of specific questions including the following examples:

1. How does the BM change when the proposed project comes on line in year n and the displaced project comes on line in year n+x?
2. How does the BM change when the size of the proposed project is different than the size of the next addition of that type of generation?
3. How does the BM change if the proposed project would have a different duty cycle than the next likely capacity addition absent the project?
4. Demonstration of how the BM approach outlined in this paper would for particular power markets for which data are already available.
5. How should proposed projects be combined in analyzing displacement? For example, a single wind project may not offer any firm capacity but a collection of such projects may.
6. Can energy only projects influence the build margin? If so, how?
7. Does a proposed project merely defer an unchanged set of expansion investments or are future projects actually eliminated? What is the impact on the BM?
8. Should we accept the notion that proposed projects below a certain size have no impact on the BM on a prima facie basis?
9. The examples in this paper have focused on grids dominated by fossil-fired generation with an assumed market structure that attempts to assure that least cost expansion plans and economic dispatch are followed. Markets dominated by both run of river and storage hydro units raise different concerns that should be addressed.
10. How are capacity investment decisions made in one part hourly markets that pay only for energy on a $/MWh basis?
11. The correct OM for systems that include pumped storage hydro units that are used for peaking would be a useful topic to cover.

12. Appropriate treatment of cogeneration both in the case in which heat is the primary output and the case in which electricity is the primary output.

This paper has also opined that sophisticated modeling of power systems will not be an effective approach for the baselines that are needed based on the budgets and timelines that will apply to the needed baselines for upcoming projects in the electric sector. However, there was interest in modeling at the workshop. If there were a groundswell of interest in this topic, it would be advisable to construct a set of two or three system examples and to then solicit demonstrative results from a number of the leading vendors of such software to evaluate the range of results achieved and to explore the methodological differences that lead to those results.

3.3 Recommendations To The CDM Methodology Panel

This paper and probably many others have raised specific issues with ACM002 and made suggestions on alternative methods that would provide improved results, at least under certain circumstances. Unfortunately, there is currently neither mandate nor an established process for further dialogue on such ideas. To move ahead, it would be very useful if the CDM Methodology Panel were to consider both procedural and technical reforms that would help to elevate electric sector projects to achieve their expected contribution to carbon reductions in the first crediting period.

Recommended procedural initiatives for 2005 include:

1. Establish an agenda for 2005 and 2006 that identifies the highest priority topics on electric grid baselines that should be addressed.
2. Establish a regular process for soliciting and responding to comments on proposed rulings within a specified timelines.
3. Work with others in the carbon community to establish quarterly or semiannual workshops to continue the types of dialogue begun in Buenos Aires between CDM and those preparing baselines for electric sector projects.
4. Prepare Terms of Reference for three to six studies to be conducted in 2005 to address some of the topics suggested above or other research priorities identified in Item 1.[17]

As is evident from this paper, the primary technical concerns with ACM002 relate to the suggested use of historic data to estimate build margins and to the default use of equal weighting of the OM and the BM in establishing project CEFs. Given that ACM002 methodologies are likely to dominate the near term baseline approaches for electric sector projects, any refinements on these topics should be considered as high priorities. The first eight topics listed in Section 3.2.2 would constitute a convenient scope of work for a research study designed to resolve issues and to establish additional approved methodologies. The remaining list of topics above could also be addressed in research

[17] It is anticipated that CDM would not have sufficient financial resources to commission studies or to fund the workshops. However, their willingness to identify the issues of primary interest and to act on the results of the studies is essential before others can step forward with potential funding to advance the CDM regulatory process.

studies either in isolation or in combination with other high priority topics that CDM would identify.

Annex A List of Workshop Attendees

"Power Grids and CDM Methodologies Workshop for CDM Stakeholders"
Activity #P093487
December 8, 2004
Buenos Aires, Argentina

START DATE: 12/08/2004	START TIME: 09:00:00 AM
END DATE: 12/08/2004	END TIME: 05:00 PM

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Annex B Presentation Abstracts

The workshop was intended to stimulate discussion among attendees and did not include development or publication of papers by each presenter. The PowerPoint versions of all presentations are, however, available from the CFB website. Many of the key points covered in the presentations have been highlighted in the textual discussions in the main text. This section provides brief abstracts of each presentation as a guide to further deliberation and contacts for readers interested in further discussion of issues of mutual interest.

Ken Newcombe
Carbon Finance Business
Keynote Speaker, Opening Remarks

Ken Newcombe opened the workshop with a high-level overview of the state of the art in establishing practical baselines for grid displacement projects and of the historic difficulties encountered in this rapidly evolving field. He was the first of several speakers to note the trade-offs between environmental integrity and transactions costs in reaching an effective balance in grid baseline methodologies. He further reflected on how this challenge has constrained the CDM regulatory response and how that response has, in turn, constrained development of grid displacement projects. Finally, he juxtaposed the timeline for development of grid generation projects with the first crediting period and concluded that the window of opportunity for such projects is rapidly narrowing. For this reason, he sees some urgency in expanding and expediting the regulatory response to minimize forgone opportunities. That view provided a cornerstone rationale for the importance of this workshop and subsequent research and dialogue to accelerate advancement of the state-of-the-art.

Jane Ellis
OECD
Electricity Projects in The Developing CDM Portfolio

Ms. Ellis provided an interesting review of the total portfolio of CDM approved projects and the role that electric generation projects have played compared to expectations. Her key findings included:

- Of 201 total CDM projects, 107 include electric generation.
- While more than half of the total projects include electric generation, they tend to be relatively small and account for less than 25% of total CO2 emission reductions for the 2008-2012 period.
- The situation is getting worse rather than better over time as the share of electric projects is declining.
- Contributing causes include the relatively small carbon contributions to total project costs and the relatively high CDM risk for grid displacement projects.
- End of pipe solutions are offering much simpler and larger carbon reduction projects and are, therefore, increasing their share of the CDM portfolio.

Sebastian Bernstein
Synex Ingenieros Consultores
Power Grids and CDM Methodologies

Mr. Bernstein provided a very interesting overview of the operation of the Chilean power market which he indicated is a reasonable prototype for most Latin American markets. The Chilean market utilizes centralized dispatch driven by variable costs of generation. Spot prices track short run marginal costs of generation rather closely. Bilateral contracts are the dominant means of securing new capacity additions for the grids with the contract prices being set by the all in prices for new generating units. Over time, the spot and contract prices are expected to converge although differences will always remain due to forecast uncertainties. For Chile, the build margin is currently defined by gas-fired CC units while the operating margin is a mixture of gas and coal units. Mr. Bernstein believes that the build margin must be given heavier weight than the operating margin when new the proposed project clearly defers or replaces new capacity additions.

Stephen Wilson
Economic Consulting Associates Limited
Power Grids in Asia

Mr. Wilson provided comparative snapshots of power widely divergent power markets in China (380 GW/10% AGR), India (112 GW/6% AGR), Thailand (25 GW/7% AGR) and Vietnam (10GW/9% AGR). With these very high annual growth rates across the region, the build margin would seem to be the dominant consideration for all of these markets either now or in the very near future.

China is currently comprised of several separable grid systems but ties are being strengthened which will soon transform the definition of the relevant power markets for both build margin and operating margin consideration. Hydro and gas generation is treated as must run so coal units constitute the marginal operating resource. The all-in cost of new gas generation (excluding non-fuel O&M) is $55/MWh compared to $34/MWh for new coal based on current gas prices of $5.50/MMBTU and coal at $2.22/GJ.

India is a thermally dominated generation system that also has several separable grid systems with rapidly improving integration. Both the addition of transmission projects and the change from traditional to market-based models can radically alter dispatch and the related operating margin definition. For India, the all-in cost of new gas generation is $36.50/MWh compared to $40/MWh for coal again disregarding O&M costs. However, these results are based on a highly subsidized gas price of $3.00/MMBTU compared to a true cost of $5.14/MMBTU. The cost of coal is $2.05/GJ.

Thailand and Vietnam are much smaller power markets. In Thailand, the marginal plant is a gas-fired CCGT. Vietnam currently has a system that is comprised of hydro and

CCGT generation but a nuclear unit is planned and a coal unit is possible in the near future.

In summary, Asian markets are dynamic and build margins are critical in establishing CEFs.

Michael Lazarus
SEI/Tellus Institute
The Combined Margin Approach: Issues and Options

As noted in several places in the main text of this paper, Mr. Lazarus provided expert guidance on both the substance of the combined margin approach and some of the thought processes that led to the methodology promulgated in ACM0002. Like many others he began by noting the partially conflicting criteria that are considered in developing baseline methodologies including accuracy, feasibility, transparency, consistency, and credibility. Generally, increasing performance on one of these measures will require diminished performance on some of the others. In addition to summarizing the approved methods of estimating both the OM and the BM, he addresses the following key issues:

- The trade-offs between simple and complex models
- Whether proposed projects delay or displace grid capacity additions and the implications for the build margin,
- Ex-ante vs ex-post analysis.

Perhaps the most encouraging message for many workshop participants was the open acknowledgement that there are many remaining areas for improvement and refinement of the existing methodologies. Though he was speaking only for himself and not in any official capacity as a member of the CDM Methodology Panel, he seemed to invite further development of grid displacement methodologies and to welcome new ideas on the key issues that he raised.

W. Vegara and A. Deeb
World Bank
World Bank's Experience with CDM Methodologies for the Power Sector

Mr. Vergara reported on two projects in Colombia where 65% of grid capacity is hydro and 80% of energy comes from hydro. The projects include a 20 MW wind farm and an 80 MW run of river hydro project. This presentation includes interesting illustrations of how carbon benefits can be combined with both other environmental achievements and social benefits to build broader than traditional justification for projects. One of the most stimulating results was a comparative analysis of a wide range of seemingly plausible methodologies for estimation of operating margins, build margins and combined margins. As shown in Figure 2-10, the range of results for each margin varied by a factor of 2 to 1 but application of the ACM0002 approach leads to CEFs that are well below the entire range of alternative estimates. If these results reflect legitimate interpretations of the relevant guidance they would indeed cause concern about ACM0002 in these circumstances.

Fernando Cubillos
Carbon Finance Business of the World Bank
World Bank Experience With Power Sector Baselines

Mr. Cubillos summarized some of the experiences of CFB with run-of-river hydro and wind generation projects in Central and South America. The CFB perspective for many of these projects was quite different since these carbon purchases were governed by agreements that often predated issuance of CDM rules for grid displacement projects. In general CFB has found that carbon revenues will cover from 5% to 15% of the investment costs for electric sector investments. Since payments are on delivery, these funds are not available for up-front investment but can be used to secure additional debt financing.

Mr. Cubillos provided a clear and simple additionality criterion that CFB applied for these projects. If the proposed project increases the cost of the least-cost expansion plan, it is considered to be additional.

The project example for this presentation was a 26 MW run-of-river hydro project in Chile. Since firm capacity from this project is less than 4.0% of the economic size of unit additions for the Chilean grid, the impact on capacity additions was considered to be minimal and the OM was chosen as the relevant displacement concept. Given excellent cooperation with the dispatch center, ongoing monitoring based on hourly dispatch data that identifies the marginal units has been established. This provides a very good example of the effort required to monitor a project based on hourly dispatch data for cases where access to such data can be secured.

Mr. Cubillos listed the following open issues for CDM to address with respect to grid displacement projects:

- Project sequencing and seniority. How does one CDM grid displacement project take account of other proposed CDM grid displacement projects?
- Firm capacity for a single project vs. many similar projects. For example, one wind generator would have a different per unit impact on the build margin than 20 or 30 such projects at different locations.
- Storage hydro emission factors and dispatchability. In general, storage hydro will be used to the maximum extent to cover peak loads as a principle of least cost operation of a grid. Thus, storage hydro may appear to be the marginal unit for the peak hours. However, regardless of any proposed CDM projects, storage hydro generation will be used to the maximum extent and will not be displaced. Thus, the true marginal unit for those hours should be the next units below storage hydro in the dispatch order.[18] Even if storage hydro were somehow displaced, it

[18] Kartha, Lazarus and Bosi address this point in Baseline recommendations for greenhouse gas mitigation projects in the electric power sector, Energy Policy 32 (2004) and also advise that storage hydro be excluded from operating margin analyses.

would be necessary to account for the low load period generation that is used for recharge pumping.

Duane T. Kexel
Power System Engineering, Inc.
CDM Consolidated Methodology for Electric Sector Baselines
Issues and Proposed Answers

Although this paper has provided expanded treatment of many of the issues addressed in my presentation, an abstract of the issues addressed in my presentation is provided here as a guide to those who may wish to download the presentation from the CFB website. In outline form, the key issues addressed in my presentation were:

- Baseline development must balance transactions costs against the costs of foregone carbon reductions.
- Inaccurate baselines diminish carbon reductions both by paying for phantom ERs and by not paying for real reductions.
- In general, OMs should be based on ex-post monitoring and BMs should be based on ex-ante analysis.
- The illustrative project was from the Czech Republic where the BM is not relevant and the OM should be given 100 weight through, at least, 2010.
- The simple ACM0002 methods will often overstate legitimate ERs.
- The ACM0002 dispatch method is conceptually correct but demands excessive data and monitoring effort for many projects. A simplified version of this conceptual approach would be very useful.
- Three methods of establishing the marginal fuel-technology mix for OM analysis were presented (statistical, screening curve, and proxy unit methods)
- Arguments were offered to show why historical OM data will seldom be reasonable and ex-post monitoring should be required if possible. Historical data should only be used as a default option in case better data is not available.
- Guidance was presented on deciding whether the OM analysis should be on a monthly, seasonal or annual basis.
- Methods for simplified treatment of net exports were provided.
- Regarding ACM0002 BM methods, concerns were expressed about the accuracy of predicting future additions based on recent historical observations. It was also noted that “energy-only” projects can also impact the capacity expansion plan.
- An alternative BM methodology was proposed.
- Weighting of the OM and BM based on 100% OM in the near term and 100% BM in the future will often be more accurate than the ACM0002 default of equal weights.