RULING

IN THE MATTER of an Application Dated March 21, 2005 by the New Brunswick Power Distribution and Customer Service Corporation for the Approval of a Change in its Charges, Rates and Tolls for Cost Allocation, Rate Design and Load Forecast

December 21, 2005

New Brunswick

Board of Commissioners of Public Utilities

The New Brunswick

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IN THE MATTER of an Application dated March 21, 2005 by the New Brunswick Power Distribution and Customer Service Corporation for the Approval of a Change in its Charges, Rates and Tolls.

Board:

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M. Douglas Goss, Senior Advisor
John Lawton, Advisor
Peter A. MacNutt, Board Counsel
John Murphy, Consultant
Arthur W. Adelberg, Consultant
Steven S. Garwood, Consultant

Applicant:

New Brunswick Power Distribution & Customer Service Corporation	Rock Marois, Vice President Lori Clark, Business Director Neil Larlee, NBP Holding Corporation David Hashey, Q.C., Solicitor Terry Morrison, Q.C., Solicitor Malcolm R. Ketchum, Consultant

Formal Intervenors:

Canadian Manufacturers & Exporters	David Plante
Conservation Council of New Brunswick	David Coon
Canadian Broadcasting Corporation	
Eastern Wind Power Inc.	Paul Woodhouse Peter MacPhail, Solicitor
Enbridge Gas New Brunswick Inc.	Shelley Black, Manager Regulatory Affairs Ruth York, Regulatory Analyst David MacDougall, Solicitor Dr. Alan Rosenberg, Consultant
Irving Paper Limited	William Dever Andrew Booker
Irving Pulp & Paper Limited	Kevin McCarthy Mark Mosher
J.D. Irving Limited	Wayne Wolfe Thomas Storing
Jolly Farmer Products	Jonathan English
New Brunswick Municipal Electric Utility Association	Richard Burpee, Saint John Energy Eric Marr, Saint John Energy Dana Young, Saint John Energy Charles Martin, Energie Edmundston Dan Dionne, Perth-Andover Electric Light Raymond Gorman, Q.C., Solicitor Paula Zarnett, Consultant
Rogers Cable Communications Inc.	Christianne Vaillancourt Leslie Milton, Solicitor John Armstrong
Self Represented Individuals	Jan Rowinski Eric Allaby Chris Baker Erik Denis Shawn Graham Stuart Jamieson Roly MacIntyre

Telegraph Journal	
Vibrant Communities	Tom Gribbons Kurt Peacock
Public Intervenor:	Peter Hyslop
	Carolanne Power Robert O'Rourke, Consultant Robert D. Knecht, Consultant Donald Barnett, Consultant

Informal Intervenors:

Agriculture Producer's Association of New Brunswick	Jonathan English
Canadian Council of Grocery Distributors	Jeanne Cruikshank
City of Miramichi	John McKay
Energy Probe Research Foundation	Thomas Adams David MacIntosh
Falconbridge Limited	Jean-Guy Paulin Ted Shannon
Flakeboard Company Limited	Barry Gallant
New Brunswick Power Generation Corp.	Rick McGivney
New Brunswick System Operator	William Marshall Kevin Roherty
Potash Company of Saskatchewan	George Bollman
Terry Thomas Consulting	Terry Thomas
UPM-Kymmene Miramichi Inc.	Juha-Pekka Jutti

The New Brunswick Power Distribution and Customer Service Corporation (Disco) filed an application with the New Brunswick Board of Commissioners of Public Utilities (the Board), dated March 21, 2005, for approval of a change in its charges, rates and tolls. Section 101 of the Electricity Act (the Act) requires Disco to apply to the Board for approval of changes in its charges, rates and tolls where such changes exceed the amount authorized under Section 99 of the Act.

Disco requested the Board to hear the application in two phases described as follows:

Phase One: Requested the Board to make an order that would allow it to recover, at a later date and in a manner determined by the Board, the amount by which its fuel costs, encompassed in its purchased power costs as of April 1, 2005, exceeded the amount recovered through its charges, rates and tolls as currently filed. Additionally, it requested approval of a variable fuel surcharge.

Phase Two: Requested approval of its revenue requirement, cost allocation and rate alignment proposals and its proposed rates, charges and tolls as filed with the application.

The Pre-hearing Conference began on May 17, 2005. Parties presented their requests for intervenor status and language preference for the hearing. Disco stated that it believed the Board must decide on the phasing proposal and the hearing process before establishing a schedule for the hearing.

Various parties presented oral arguments concerning Disco's request for approval of a fuel variance account (deferral account) and a variable fuel surcharge. The Board requested the intervenors to submit written briefs in support of their arguments by May 24, 2005 with Disco to submit rebuttal comments by May 26, 2005. As well, the Board heard arguments from Disco, the New Brunswick Municipal Electrical Utility Association (the Municipals) and Rogers Cable Communications Inc. (Rogers) with respect to the Board's authority, if any, to set rates for pole attachments by third parties.

The Pre-hearing Conference reconvened on May 30, 2005. The Board issued its ruling with respect to Disco's requested use of a fuel variance account. The ruling stated that to allow the use of a fuel variance (deferral) account to recover costs incurred prior to the effective date of the Board's final decision would be tantamount to the approval of interim rates. The Board's opinion was that it did not have authority under the Act to approve interim rates and would not approve such use of a deferral account. Disco requested an adjournment of the conference that was granted until June 8, 2005.

On June 6, 2005, Disco sent a notice to the Board advising that pursuant to Section 99 of the Act, it would be increasing its rates by 3 percent effective July 7, 2005. The increase replaced Disco's request for a change in its rates in the current application for the 2005/06 fiscal period.

Disco sent a second letter dated June 6, 2005, advising all parties that it was filing an amendment to its application. The amendment requested changes to Disco's charges, rates and tolls for its fiscal period 2006/07.

On June 8, 2005, Disco proposed proceeding with interrogatories on the cost allocation and rate design (CARD) segment of its application immediately. Evidence for the revenue requirement for 2006/07 would be filed in October 2005. The Board accepted Disco's proposal.

Board staff retained Energy Advisors, LLC (Energy Advisors) and Mr. John Murphy to assist with the review of Disco's CARD evidence. Energy Advisors were also retained to prepare and file independent evidence for the CARD segment of the application.

There had been considerable debate among the parties concerning the interpretation of Section 156 of the Act. That section states that for Disco's first hearing under the Act, assets transferred to or acquired by it on or before April 1, 2003 were deemed to have been prudently acquired and useful. Section 156 also states that any expenditures arising out of the power purchase agreements (PPAs), entered into on or before the proclamation of that section are deemed to be necessary for the provision of the service.

Parties stated their arguments concerning their interpretation of Section 156 at the hearing on June 8, 2005. Disco argued it was a separate legal entity and that the asset transfers and PPAs were determined by Government, were public policy decisions and not subject to review by the Board. Additionally, the Board must accept the asset transfers and costs and that any underlying information and documentation was not relevant to the current application and should not be considered. Eastern Wind Power agreed with the applicant's position.

The Conservation Council of New Brunswick (CCNB) argued that the monopoly situation that occurred before the electricity market opened persisted for the distribution company in terms of where it could acquire its electricity at that moment. Therefore the PPAs should be "fair game" for this hearing as parties were not in fact dealing with two separate corporate entities (Genco and Disco), but dealing with functional entities within NB Holding Company. CCNB and the Public Intervenor noted that the PPAs were signed by the same individual acting on behalf of different companies.

EGNB argued that Disco was entitled to recover costs that were prudently incurred. However, Section 156 did not preclude the Board from obtaining underlying information and documentation for purposes other than reviewing the prudency of the costs.

Mr. Denis, representing himself, argued that the supporting documents were relevant. He stated that it was for the Board to determine the relevance of those documents that have consequences and effects on rates and on fuel costs.

The Municipals argued that the Board should consider any and all documents and their relevance. Also that Section 156 included no restriction on access to documents.

The Public Intervenor argued that costs arising from the PPAs likely represented 75% of Disco’s total costs. He stated that parties should know what are the costs in the PPAs and how they affect Disco. He questioned how the Board could determine if Disco’s rates were fair and reasonable without access to the underlying costs and rates of return.

The Board ruled on June 9, 2005 that the total costs represented by the PPAs must be accepted as a necessary component of Disco’s revenue requirement. In meeting its objective to set fair and equitable rates, the Board must ensure fairness in the allocation of all costs between customer classes and ensure that rates reflect the true economic costs of power on a go-forward basis. The Board noted that Disco relied heavily on its revenue to cost ratios for the customer classes to support its proposed rate changes. It concluded that the evidence that supported the ratios must be tested in the most thorough fashion to ensure that fair and equitable rates are set. The Board stated its belief that if the NB Power Group of Companies had information that would assist in setting rates then that information should be made available to this hearing process.

The Board also ruled that Section 156 did not include any confidentiality provision for information covered by that section. It directed Disco to provide answers to the information requests on the costs that underlie the PPAs and any documents or information that the Board considered relevant for the purpose of setting just and reasonable rates.

A Motions Day was held on June 24, 2005 regarding interrogatories for the CARD segment of the application. Disco objected to responding to two interrogatories and requested approval to file responses to a number of other interrogatories on a confidential basis. It also maintained that some interrogatories concerned the revenue requirement segment of its application and that it would respond to those interrogatories during that stage of the hearing process.

The Public Intervenor's interrogatory Disco (PI) IR-17, had requested that Disco provide copies of third party power purchase contracts. The contract between the New Brunswick Power Generation Corporation (Genco) and the Department of Natural Resources was provided. Fraser Inc., Grandview Avenue Cogeneration Corporation, St. George Pulp and Paper and Bayside Power (the NUGs) objected to filing their contracts. The Public Intervenor stated that the contracts represented approximately 16.5 percent of the generating capacity covered by the Coleson Cove PPA and should be subject to a public review.

Disco objected to providing the contracts, argued that it was not a party to those contracts and that the NUGs were not a party to Disco's application. Furthermore, it argued that the costs of those contracts were reflected in the PPA pricing to Disco and had to be accepted as prudently incurred.

Enbridge Gas New Brunswick Inc.'s (EGNB) interrogatory Disco (EGNB) IR-39 requested Disco to provide information on total generation and total fuel costs by type for the fiscal year ending on March 31, 2005. Disco objected to providing the information. The Board deferred ruling on the objection until the hearing day set for Disco’s claim for confidentiality on some of the information included in the interrogatory responses.

Also at Motions Day, the Board set a schedule for the CARD hearing. It allowed for three rounds of interrogatories to the applicant and their responses, filing of intervenor evidence and a round of interrogatories on that evidence, a hearing day on confidential filings and an additional motions day. The CARD segment of the hearing was set to commence on September 26, 2005 and the Revenue Requirement segment set for January 16, 2006. The NUGs were notified of the Confidentiality Hearing Day to provide them an opportunity to attend the hearing if they so desired.

The Confidentiality Hearing was held on July 11, 2005. The Canadian Broadcasting Corporation and the Telegraph Journal (the Media) petitioned the Board for full formal intervenor status in the proceeding for use when the Board dealt with matters of confidentiality. As well, the Media requested that it be given advance notice of all future interlocutory proceedings to hear motions requesting matters of confidentiality and that they be allowed to attend, record and broadcast all proceedings.

The Media was interested in whether the Board should receive any material in confidence. If it did so, on what basis and if the Board should have in-camera hearings. The Board granted the Media formal intervenor status limited to appearances on motions regarding confidentiality and to view information at in-camera hearings.

At the Confidentiality Hearing, Genco, the NUGs and the intervenors presented their arguments regarding the third party contracts and the PPAs. Genco provided some information on its fuel purchasing practices and its exposure to gas price variances in the NUGs' contracts. The NUGs noted that the Board did not regulate Genco and had no authority to order the disclosure of the third party contracts. They also addressed the confidentiality of information contained in their contracts.

The Hearing continued on matters concerning confidentiality on July 12, 2005. Parties continued with their arguments on the application of Sections 133 and 128 of the Act.

At the continuation of the Pre-hearing Conference on July 27, 2005, the Board ruled on a number of issues. Disco was ordered to file information with the Board in unredacted form and to file specific redacted information on the public record. It also ruled that it did not have jurisdiction to order the NUGs' contracts to be filed in the current application.

Additionally, the Board ruled that it was appropriate for all media, including television, to cover the Board's public hearing proceedings and to be able to broadcast recordings from the proceedings. It ruled that it considered it appropriate to assist in providing a procedure to give notice to the media of upcoming hearings to consider requests for confidentiality.

A second Motions Day was held on August 25, 2005. The applicant requested approval to file responses to certain information requests in confidence. The Board approved the request. A hearing day was scheduled for September 19, 2005 at which time parties could argue for and against the confidential nature of the Disco's responses.

The Board ruled on August 25, 2005 that it would only consider the load forecast information specific to the test year, 2006/07, in the current application. With the agreement of Disco, it stated that it intended to hold separate generic hearings on Disco's 10-year load forecast and its customer service policies following the decision in the current rate application. This ruling was made in order to attempt to have the rate decision completed in time to have the approved rates in place on April 1, 2006.

At the continuation of the Hearing on September 19, 2005, the Board ruled on Disco's confidentiality request for some information included in its responses to information requests. It set October 6, 2005 to hear arguments with respect to its jurisdiction to set rates for pole attachments by third parties (Rogers). This concluded the Pre-Hearing Conference.

For the CARD segment of the application, the following schedule was set for cross-examination of the various panels that had submitted evidence on behalf of the parties.

September 26, 27, 28 & October 3, 4, 5 & 6, 2005	Disco Panel	Mr. Marois, Mr. Larlee & Mr. Ketchum
October 26 & 27, 2005	EGNB Panel	Dr. Rosenberg

October 31 & November 1, 2005	Public Intervenor Panel	Mr. Knecht
November 2 & 3, 2005	Board Panel	Mr. Adelberg & Mr. Garwood
November 7 & 8, 2005	Municipals Panel	Ms. Zarnett

OVERVIEW

The purpose of a cost allocation study is to fairly allocate costs among the various customer classes on the basis of cost causation. The objective of rate design is to develop rates that are just and reasonable and that will recover the costs.

The nature of the electricity business is such that certain assets (eg. generating plants, transmission lines) are used to provide service to more than one customer class.

The entire electrical system works together to provide the electricity necessary to serve the needs of the customers in New Brunswick. Customer requirements vary throughout the year and the peak demand that they put on the system is not known for many customers. For these reasons, it is impossible to allocate the cost for each individual asset to the different customer classes in a definitive manner. There are different methods that can be used.

Once costs are allocated, the next step is to design the rates that will recover those costs. The general approach to rate design is to collect some revenues on the basis of fixed charges (eg. monthly service charge) and the remainder from usage charges (eg. cents per kilowatt hour of electricity used). It is possible to develop significantly different rate designs that will produce the same total revenue. The allocation of costs and the design of rates both require informed judgement.

The traditional approach is to determine the costs that each class is responsible for by functionalizing, classifying and allocating the total costs. The first step is to split the costs into the three main functions of generation, transmission and distribution. The second step is to classify the costs as demand, energy or customer-related. The final step is to allocate the demand, energy and customer costs to each class on the basis of appropriate parameters.

Once the costs for each class have been determined, rates are developed to recover the costs from each class based on the expected requirements of each class. Each of these steps is discussed below. Unless stated otherwise, the approach recommended by Disco is approved by the Board.

FUNCTIONALIZATION

The Board approves the way Disco assigns its costs to generation, transmission and distribution.

CLASSIFICATION

Disco classified its generation costs as either demand or energy-related, its transmission costs as demand-related and its distribution costs as demand or customer-related.

Generation Costs

Disco's costs related to generation (purchased power) are estimated to be just under 80% of its total costs for 2006/07. This is obviously the single most important expense and its classification will have a significant impact on the rates that are ultimately paid by each customer class.

Proclamation of the Electricity Act (the Act) on October 1, 2004 restructured the New Brunswick Power Corporation (NB Power) into several new companies, one of which is Disco. The Act also created the New Brunswick Power Generation Corporation (Genco) and the New Brunswick Power Nuclear Corporation (Nuclearco). Subsequently, the government created the New Brunswick Power Coleson Cove Corporation (Colesonco).

NB Power had operated as a fully integrated electric utility and performed all three functions of generation, transmission and distribution. As of October 1, 2004 Disco has been responsible for the distribution function and Genco, Nuclearco and Colesonco have jointly been responsible for the generation function. Another new company, New Brunswick Power Transmission Corporation (Transco) has been responsible for the transmission function. All five companies are subsidiaries of the New Brunswick Power Holding Corporation (Holdco). The president and chief executive officer of Holdco is the president and chief executive officer of Disco, Genco, Nuclearco, Colesonco and Transco.

Disco has entered into PPAs with each of Genco. Nuclearco and Colesonco that will provide it with the energy and capacity to serve its customers in 2006/07. The PPAs were developed by a working group from the provincial Departments of Energy and Finance with advice from financial advisors and energy experts. NB Power provided financial data and modeling support. The PPAs were approved by the Minister of Energy and implemented on October 1, 2004. The PPAs can be modified by the Board of Directors of the Electric Finance Corporation, a crown corporation.

The Genco and Nuclearco PPAs cover virtually all the generating capacity in New Brunswick, including that of non-utility generators (NUGs). These two PPAs determine how much Disco will pay for the energy and capacity that it will require in 2006/07.

Disco's submission was that the Board must look at the PPA costs because they are what drives Disco's costs. Disco also stated that any methodology for cost allocation must be sustainable in the long run. Disco submitted that it will not have access to the accounting costs of generators, including Genco, on a go-forward basis and that it would therefore be impossible to do an embedded cost study using anything but the PPA cost causation.

The Genco PPA includes both fixed and variable cost components. Disco classified the variable costs as 100% energy-related and the fixed costs as 100% demand-related. The Nuclearco PPA is priced solely on an energy basis. Disco, however, considered that this PPA represents a supply of both energy and capacity and that it would not be reasonable to classify the entire cost as energy-related. Disco therefore separated out the cost of the fuel and assigned it as 100% energy-related. The remaining costs were split 40% demand and 60% energy based on the split of fixed generation costs that was approved by the Board in its April 15, 1992 decision.

In essence, Disco recommends the use of the PPA costs, as billed, where Disco believes this is reasonable and the use of the Board approved 40/60 split where Disco believes the PPA bill approach is not reasonable.

The Public Intervenor took the position that the Board should continue to apply the 40% demand, 60% energy split to all fixed generation costs as was approved in the April, 1992 decision. The Public Intervenor believes that such an approach would be fair and based on an acceptable methodology that was approved after a full public hearing. The Public Intervenor stated that an important consideration is that nothing has really changed since 1992 with respect to the overall generation economics and that therefore the 40/60 split remains appropriate.

EGNB considers that NB Power is an unbundled utility in name only and that it looks and acts exactly like a vertically integrated utility. EGNB recommends the use of a cost causation approach and considers that Disco's classification of the Genco PPA fixed costs as 100% demand-related is inappropriate.

EGNB specifically recommends the use of a Peaker Credit Method that properly recognizes fuel symmetry. Fuel symmetry is a phrase used to describe the trade-off between more capital costs to save fuel costs or more fuel costs to save capital costs. The EGNB proposal is based on a Disco update of a peaker credit analysis that was done in 1993. The update by Disco uses 2002 cost information and does not include any NUGs.

Energy Advisors agreed with the use of the PPA costs and considered Disco's approach to the classification of the Nuclearco PPA costs to be reasonable. However, Energy Advisors recommends that the Genco PPA fixed costs, other than the fixed operating, maintenance and administration costs, be split 40% demand and 60% energy to be consistent with the treatment of the Nuclearco fixed costs.

The Board considers that a proper classification of generation costs is critical to the establishment of just and reasonable rates. Classification of generation costs should be based upon a careful analysis of how the entire group of generating facilities operates together to meet the energy and demand requirements that are placed on the system. An examination of each specific facility is required to determine the role that it plays in providing energy and capacity and the costs involved in so doing. The Board, in a ruling on June 9, 2005, stated:

"The Board's regulatory jurisdiction is set forth clearly in the Electricity Act. It has broad regulatory jurisdiction over the Transmission Company, the System Operator and Disco. Section 136 of the Act gives broad powers to the Board to require any of those entities to file with it any documentation or information in their possession. The Act is also clear that the Board has no jurisdiction over the generation companies. We do believe strongly that if the NB Power group of companies has information that will assist this Board in establishing fair and equitable rates for the customers of Disco, then that information should be made available to this hearing process."

Despite this request no detailed cost information, for the various generating facilities that will provide energy and capacity in 2006/07, was provided for examination.

If a competitive marketplace for energy and capacity existed in New Brunswick a detailed analysis of specific generating facility costs would not be necessary. The prices for energy and capacity would be established by the market and there would be no need to classify generation costs in a cost allocation study.

The White Paper “New Brunswick Energy Policy” was approved by Cabinet in December, 2000. It provides the comprehensive energy policy of the Province and contains the following statements:

“the Province will proceed by introducing wholesale competition and allowing non-utility generation and retail competition for large industrial customers (page 16)

the Province will direct the market design committee to make recommendations regarding issues related to establishing a workably competitive electricity market and for mitigation of market power in the context of the wholesale and large industrial electricity market (pages 19, 25)

the Province will give the Board the authority to monitor the competitiveness of the wholesale market and ensure that the Crown utility is unable to exercise market power” (page 28)

These statements clearly demonstrate that government policy is to establish an environment in which competition for wholesale and large industrial customers can occur in an effective manner. The White Paper also discussed how such competition could occur and said:

"Economic theory and recent experience suggest that, at a minimum, approximately five equally sized firms are required to achieve a workably competitive market. Either the Crown utility's generation portfolio must be broken up or the province's transmission interconnections with adjacent markets must be significantly increased to allow for greater access to New Brunswick." (page 18)

The Electricity Act does not contain any sections that run counter to the government policy as expressed in the White Paper. However the current situation does not promote the development of a competitive electricity market in New Brunswick.

There has been no increase in interconnections with adjacent markets so it is not physically possible for any significant supply of electricity from the New England market to enter New Brunswick in competition with in-province generators. NB Power's generation portfolio has not been broken up and worse, possible competition in-province from the NUGs has been severely limited, if not completely eliminated, by the fact that virtually all of their production is covered by contracts that have been assigned to Genco.

The Board commented on this situation in its July 27, 2005 ruling as follows:

"This Board is of the view that its ability to discharge its duties, both in respect of retail rate review and in market monitoring to foster competition in generation, has been severely compromised by the assignment of the NUG PPAs to Genco rather than the Applicant.

The Board is also of the view that the situation can be best remedied, and the legislative intent of the Act best met, by the Minister exercising his discretion through the Order-in-Council process to reassign the NUG PPAs from Genco to the Applicant."

Exit fees have not been established and no wholesale or large industrial customer has indicated any intention to obtain any of its electricity from a supplier other than Disco. Disco, in turn, receives 100% of its supply of energy and capacity through the PPAs with Genco, Nuclearco and Colesonco.

A competitive market does not exist in New Brunswick today nor does the Board believe one will develop by 2006/07. The Board agrees completely with those parties who stated that, for all practical purposes, the NB Power group of companies continues to operate as an integrated utility. The physical operation of the electricity market in New Brunswick has changed little, if at all.

The absence of a competitive market for energy and capacity means that a careful analysis of the actual costs of generation should occur to best establish fair and equitable rates. However, no detailed cost information, on the actual generating facilities, was provided and the Board does not have the authority to order it to be provided. This places the Board in a very difficult position. It does not have all the information, that clearly exists, that would normally be available to assist in setting rates. The Board will, however reluctantly, fulfill its obligation to set rates.

We consider that the most appropriate way to proceed in these circumstances is to approve a method for the classification of generation costs that will provide a reasonable approximation of the actual underlying costs. Such a method can be used until either a competitive market develops or detailed cost information is forthcoming from the NB Power group of companies.

The Board considers that the various proposals presented by the parties represent substitutes for a detailed examination of the actual costs. The method proposed by EGNB required the development of four separate classes of generation and the estimation of demand/energy splits for each class. The estimations relied on 2002 cost information for NB Power generation and did not specifically address NUGs . The Board is concerned with the lack of current and comprehensive cost information that was available to support this method. We note that the end result of this approach was a weighted average demand/energy split of 40/60. The Board further notes that both the Disco and Energy Advisors proposals rely to a certain extent on the 40% demand, 60% energy split of fixed generation costs that was approved in the April, 1992 decision. The Public Intervenor recommends use of the Board approved 40/60 split.

The one significant change, since 1992, is that certain NUGs are operated on a must run basis and not always dispatched on the basis of least cost. The Board was not provided with any cost information on the NUGs and therefore could not assess the impact of this change. Not withstanding this change, NB Power did not request any changes to the methodology that was approved in 1992. The existing methodology is the foundation for the rate structure that is in place. The Board therefore believes that it is appropriate to continue to use the method that was approved by it in the April 15, 1992 decision with respect to the classification of generation costs as either demand or energy-related.

Disco will be able to separately identify the fuel costs from the capacity costs in each of the PPAs as demonstrated by its treatment of the Nuclearco PPA. It is important to make it clear that this is not an endorsement of the Peaker Credit Method. The method hereby approved provides a classification of the generation costs that is fair and reasonable in the current circumstances. The Board therefore orders Disco to redo its cost study using the same method for the classification of the generation costs as was approved in the April 15, 1992 decision.

Distribution Costs

Disco's classification of distribution costs as either demand or customer-related was largely based on the methodology approved by the Board in its April, 1992 decision. However, Disco made changes where it believed that better information was now available and used a combination of approaches. It stated that any difference in cost allocation resulting from the use of a different method would be small and that the benefits of a detailed study of this matter would not be worth the cost.

The Public Intervenor recommended the use of the zero-intercept method and that Disco be directed to do a detailed study to develop the information necessary for implementation of the zero-intercept method. The Public Intervenor believed that more of the distribution costs should be classified as demand-related and fewer costs classified as customer-related.

Energy Advisors agreed with the approach used by Disco.

The evidentiary record in this proceeding does not provide proper support for the changes made by Disco to the methodology previously approved. The Board therefore orders Disco to classify its distribution costs as either demand or customer-related in a manner consistent with the April, 1992 decision. Disco is directed to file with the Board detailed information on the results of using various methods to classify its distribution costs within 12 months of the date of this ruling. This review should clearly address the use of capacity factor in classifying costs as either demand or customer-related.

Export Sales Credits

Disco proposed that the export sales credits be classified as 100% demand-related. It submitted that it was the availability of capacity that makes these sales possible and therefore any credits related to these sales should be credited to demand.

Disco stated that the energy costs related to exports are covered by Genco and deducted from the sale price to determine the margin that is shared with Disco.

Energy Advisors proposed that the export sales credits be classified as either demand or energy-related on the basis of the nature of the actual export sale. If the sale were for energy then the credit would be classified as energy-related and if the sale were for capacity then the credit would be classified as demand-related.

The Public Intervenor recommended that the export sales credits be credited to demand in a manner consistent with the Board’s April, 1992 decision.

The Board considers that the approach recommended by Energy Advisors requires information that may not be available and therefore is not feasible. We will accept the classification of the export sales credits as proposed by Disco for the purposes of this hearing.

ALLOCATION

General, Holdco Shared Services and Corporate Services Costs

These costs, because of their nature, generally cannot be specifically identified as either demand, energy or customer-related.

Disco recommended that the regulatory costs be allocated one-third to each of the Wholesale Class, the Large Industrial Class and the distribution level customers. Disco stated that this would be appropriate because those three groups have traditionally been involved in regulatory proceedings. Disco proposed that a number of other costs (such as senior management and corporate planning) be allocated to the same three groups primarily on the basis of their sales revenues.

The Municipals took issue with Disco's approach to the allocation of regulatory costs and the other costs that were done on the basis of sales revenues. They considered that it would be more appropriate to allocate the regulatory costs on the basis of total allocated costs. They also recommended that those costs that had been allocated on the basis of sales revenues should instead be allocated on the basis of all other allocated costs.

The Board agrees with the recommendations of the Municipals and orders Disco to redo its allocation of the regulatory costs and those costs that were allocated on the basis of sales revenues in the manner recommended by the Municipals.

Miscellaneous Revenues

Disco allocated the miscellaneous revenues to all classes served at the distribution level pro-rata based on the revenues from each class. Disco stated that it did so because there is no direct link between the costs and the revenues for miscellaneous services and also because this approach is consistent with the Board's 1992 decision.

Mr. Knecht, on behalf of the Public Intervenor, recommended that the portion of miscellaneous revenues which is related to maintaining the poles owned by Aliant should be allocated on the same basis as the allocation of the pole costs.

The Board considers that those miscellaneous revenues that are related to poles should be allocated on the same basis as the costs of the poles themselves are allocated. We are of the view that the remainder of the miscellaneous revenues should be allocated to the various classes served at the distribution level pro-rata on the basis of the costs for each class. The Board directs Disco to redo the cost study to reflect these changes. We also direct the applicant, at the time of the next review of the cost allocation methodology, to provide whatever information is available concerning the costs caused by its providing each of the various miscellaneous services.

RATE DESIGN

Residential Class

Declining Rate Block

Currently, the rate design for the residential class consists of a fixed monthly service charge and a charge for each kilowatt hour of electricity consumed. The charge for electricity is made up of two blocks with one rate for the first and a declining rate for the second. Many parties, including Disco, expressed the opinion that the declining rate block does not send the proper price signal to customers and should be eliminated. The parties disagreed over the time period for the elimination of the declining rate block.

Disco prefers a gradual approach that involves increasing the size of the first block and Energy Advisors supported this approach. Disco has not proposed a specific timetable for the elimination of the declining rate block. The Conservation Council recommended the elimination of the declining rate block immediately. EGNB is of the opinion that it is important to send the right price signals to customers. It submitted that if the Board has issues with respect to possible customer impacts, that the changes could be phased in over a period of time, not to exceed three years. The Public Intervenor recommended that the declining rate block be removed within a three to four year period.

The Board agrees that the declining rate block should be eliminated as soon as possible. We are concerned over the possible rate shock that this might create for certain customers if the change occurs too quickly. The Board has analyzed the likely impacts and believes that it is appropriate to eliminate the declining rate block in three stages. Each stage should bring the declining rate block one-third of the way to the rate for the first block. The first adjustment should occur as part of the rate changes for the 2006/07 year. The remaining two adjustments can occur at the time of future general rate changes but the Board orders that the process must be completed within five years of this date.

Farms and Churches

Farms and churches are included in the residential customer class and there was discussion about the effect that this has on the consumption and other characteristics of the class. The Public Intervenor recommended that farms and churches be removed and placed into a separate class.

Disco stated that the removal of farms and churches would require the creation of a new class. Disco submitted that this would require research and customer education and expressed concern over the possible impacts on the revenue to cost ratios.

We therefore order Disco to do research on the residential class to identify those customers whose usage profiles are inconsistent with a normal residential customer. Disco is also to develop proposals for how these customers should be classified and the impacts of any such reclassification. This information is to be filed with the Board within 12 months of the date of this ruling.

<u>General Service</u>

General Service has two classes, General Service I (GS I) and General Service II (GS II). GS II has more favourable rates than GS I and is limited to those customers who use electricity as the only source of energy for cooking, space heating, water heating and all other services.

Disco recommended the gradual elimination of the GS II class through the use of larger increases for the GS II rates than for the GS I rates. Disco also proposed that the GS II class be closed to new customers. Disco did not provide a specific timetable for the elimination of the GS II class.

The Conservation Council recommended that the GS II class be eliminated immediately. EGNB recommended that the GS I and GS II rates be equalized immediately and failing that, that the GS II class be closed to new customers. The Public Intervenor recommended that the GS II class be discontinued over the next three years.

A preliminary analysis of the usage data for the GS I and GS II customers indicates that there are distinct differences between the two classes. The Board considers that it is appropriate that the two classes be kept separate until further data is collected and more analysis occurs. We direct Disco to do a study on the usage profiles of the GS I and GS II customers and to file it with the Board within one year of the date of this ruling.

Not withstanding the need for the comprehensive review indicated above, for the purposes of the revenue requirement portion of this hearing, the Board directs Disco to file by January 16, 2006 the following General Service rate scenarios for discussion purposes:

For General Service II, the second block energy rate is to be set equal to the third block energy rate.

For General Service I, the second block rate is to be set at the same level as for GS II above. For this scenario, the demand charge for GS I is to be reduced so as to effect a revenue-neutral adjustment for the class.

Large Industrial

Interruptible Rate

The Board asked the parties if they believed that the Interruptible Rate should include a contribution to the fixed costs. Customers who have their own generation may arrange for the supply of interruptible electricity from Disco. This is available in an amount up to the customer's unused generation capability. The energy is only provided if the available resources can do so and still meet all of Disco's firm commitments. The interruptible rate is based on Disco's incremental cost of providing the energy.

Disco responded that it does not believe that there should be a demand component to the Interruptible Rate. It submitted that the interruptible customers take a fuel price risk that the other customers do not and that it is very expensive for the interrupted customers. It also stated that, if the interruptible rate is priced at market prices, there is a high probability that customers may convert to a firm load. This could reduce export sales and advance the need for additional capacity.

The Public Intervenor stated that many utilities do charge a premium to the cost of interruptible service to reflect the value of that service. He recommended that, even though there was little evidence on the record regarding the appropriate contribution, the amount be set at $3 per megawatt hour.

EGNB stated that all rates, unless based on non-economic policy considerations, should make some small contribution to fixed costs.

The Municipals recommended that the Interruptible Rate include a fixed cost component but stated that there may not be sufficient information before the Board to determine the appropriate amount.

The Board considers it appropriate that the Interruptible Rate customers should pay for some of the fixed generation costs. For most of the year, it is the in-province generation that provides the interruptible energy and at a lower rate than for firm energy. The specific amount of the contribution will be established during the review of Disco's revenue requirement.

There was discussion on whether an interruptible option should be made available to other customer classes. The Board considers that equity dictates that this option should be available but that there are various factors that must be considered. We therefore direct Disco to submit a study within one year of the date of this ruling on the costs and issues associated with providing this option.

The Public Intervenor proposed that an industrial customer be entitled only to purchase an amount up to 15% of its firm transmission load at surplus energy rates. The Board considers that this suggestion may have merit. If there were a limit on the amount of interruptible energy that each customer could purchase, it would reduce the impact that would occur if one or more customers switched to firm service. We therefore direct Disco to do a study on the maximum amount of interruptible/surplus energy that should be available to each customer and to file it with the Board within 12 months of the date of this ruling.

Seasonal Rates

EGNB recommended the introduction of seasonal rates, for both the Residential and General

Service customer classes, with higher rates for the winter season. EGNB submitted that seasonal rates can be a complement to demand side management measures and will send the appropriate price signal.

The Municipals stated that if seasonal rates are to be implemented then they should apply to all rate classes.

The Public Intervenor recommended that Disco do a study on the impact of seasonal rates and file it with the Board.

Disco stated that it was not necessarily opposed in principle to seasonal rates but, because of the customer impacts, believes they should not be implemented until after the residential declining rate block is eliminated and the GS I and GS II classes are merged.

The Board considers that seasonal rates may be an appropriate concept for New Brunswick but that implementation is not desirable at this time because of the possible customer impacts together with the other changes that are occurring. We direct Disco to provide a proposal for seasonal rates at the time of the next review of rates.

Standby Rate

Customers that have on-site generation normally have an arrangement with the electric utility for the provision of electricity whenever the on-site generation is not available. This is referred to as standby power and is often charged for by way of a monthly reservation fee. Disco does not currently have a standby rate. Co-generators, served at the transmission level, can arrange for interruptible energy but this option is not available to other co-generators. A standby rate for such customers might provide them with back-up energy at a lower cost than they currently pay.

EGNB recommended that Disco be ordered to develop a standby rate for co-generation that is based on generally accepted principles and to submit it for review. It stated that such a rate would encourage the development of co-generation in New Brunswick.

The Public Intervenor also stated that this might be a good time to introduce a standby rate.

Disco submitted that the current economics of co-generation have not resulted in a need for a standby rate similar to the one proposed by EGNB as there has been no customer interest at this point. Disco stated that it would have no problem providing a standby rate for a co-generator but would not want to do so for a merchant generator. It also said that care would need to be exercised in developing the standby rate.

The Board considers that a standby rate may well promote the development of co-generation consistent with the goals of the White Paper. We therefore order Disco to develop a proposal for a standby rate for co-generators and to include it in the evidence for its next rate application.

OTHER MATTERS

Marginal Costs

Energy Advisors stated that marginal cost analysis would likely be useful in designing rates that capture the future trend of electricity costs and should result in more efficient use of electricity.

Disco stated that it was opposed to a move to marginal cost analysis because it would be fraught with judgemental decisions. It submitted that there was no marginal cost study on the record in this proceeding and to do one requires access to detailed generation resource and cost information. Disco maintained that such a study is not appropriate for an unbundled distribution utility.

The Public Intervenor recommended that marginal cost allocation and pricing should be looked at at some point in time.

EGNB submitted that a full marginal cost study requires information that is not presently available and that the use of marginal based approaches is premature.

The Board considers that marginal costs would provide valuable information and assist in the setting of appropriate rates. A fully competitive market would provide the proper price signals but such a market does not currently exist in New Brunswick and is unlikely to develop in the near future. We agree that a proper marginal cost analysis requires detailed cost information that was not available in this proceeding. Even price signals such as time of day rates for electricity are not currently available in the province. Marginal cost information would promote the use of appropriate energy efficiency, conservation measures and load management devices such as electric thermal storage devices. However, if Disco's costs, as established by the PPAs, do not include marginal cost signals many proven energy efficiency and demand side management measures will not occur as they will not pass the normal economic tests. In the absence of the necessary cost information, the Board considers that it is appropriate to use the cost allocation methodology as discussed above.

Revenue to Cost Ratios

The Municipals submitted that the Board, in examining revenue to cost ratios, should consider that there are three transmission level customers – Wholesale, Large Industrial and Disco. Wholesale and Large Industrial are separate customer classes that take service at the transmission level. They submitted that Disco, on behalf of all the other customer classes, also takes service at the transmission level and therefore should be considered as a third class of transmission customer. The Municipals recommended that the three transmission level customers should each have a revenue to cost ratio of unity. Failing that, they recommended that the ratio for the Wholesale class should not exceed 1.015, which is the revenue to cost ratio that the Municipals had calculated for Disco.

Disco submitted that the Disco class, as proposed by the Municipals, is purely hypothetical and does not exist. Disco stated that the mix of customers served by Disco is not similar to the mix of customers served under the Wholesale class.

The Board considers that the revenue to cost ratio for each customer class served by Disco should be examined separately. We are of the view that a long term target range of .95 to 1.05 for the revenue to cost ratio for each class is reasonable. The Board recognizes that rate impact considerations will require that some classes be moved gradually to or within this range. There is also a need to develop more data to ensure that any rate changes are and will remain appropriate. We note that certain customer classes have revenue to cost ratios that remain outside the .95 to 1.05 range and are disappointed that NB Power did not make more progress in this area in the time since 1992. Although some modifications have occurred, the issue of sending the appropriate price signals has not been dealt with in any significant way. As one counsel remarked,

"It reminds one of the story about the utility executive who, upon deciding to commit suicide, threw himself in front of a glacier."

The Board considers it appropriate that specific decisions on adjustments to the revenue to cost ratios for individual customer classes be deferred until the revenue requirement review at which time the current and proposed ratios, using the methodology approved in this ruling, will be available.

Requirement for Additional Information

The following are areas where Disco has been directed to do studies and to report the results.

Classification of distribution costs

Usage characteristics of residential class customers

Usage characteristics of GS I and GS II customers

Interruptible rate option for all rate classes

Maximum amount of interruptible/surplus energy that a customer can purchase

The Board considers that this additional information will be of value in allocating costs and designing appropriate rates. Involving interested parties in the design of the research to be done by Disco would ensure that critical items are not missed, result in better information, allow Disco to combine items where appropriate and expedite the eventual review of the information.

We therefore order Disco to provide an opportunity, by March 31, 2006, for interested parties to discuss the nature of the research to be undertaken.

Load Forecast for 2006/07

Parties have agreed with the Board's proposal that a detailed review, of the methodology used by Disco to prepare load forecasts, will be conducted subsequent to the revenue requirement hearing.

The Board approves the load forecast for 2006/07 as provided by Disco.

Public Intervenor's Request for Board Orders

The Public Intervenor requested that the Board issue seven specific orders, the details of which are provided at pages 2469-2471 of the transcript. Disco expressed considerable concern over the orders.

The Board considers that the content of each of these orders has been addressed above and that no further comment is necessary.

Delivered at Saint John New Brunswick the 21st day of December, 2005.

Partial Dissent by Commissioner Sollows

I concur with my fellow Commissioners in the orders and rulings presented above, with two exceptions. Both exceptions are based on facts revealed by my examination of Disco's billing data. These data were in evidence during the proceeding, but no participant provided an analysis of them to highlight the implications and facilitate their use in this hearing. Had I not made my own analysis of the data, which I was able to do because of my professional background, I expect that I would have agreed with my colleagues on all matters.

I understand and appreciate that my colleagues cannot properly base their decision on insights gained from my analysis. Neither do I believe that Board member's should normally be able or expected to conduct such analyses. In the normal course of affairs, this Board would have the power of general regulatory oversight over Disco. It would have been able to use this power to ensure that Disco had prepared an analysis of the data prior to the application for a rate increase. This Board does not have general regulatory oversight of Disco and could not, therefore, provide any direction to Disco prior to the rate application being filed.

This matter has not followed the normal course of affairs, and my colleagues and I now confront a different set of facts on which to base our decision. Just as my colleagues cannot properly rely on my insights into Disco's billing data, I feel that I cannot ignore them. Giving due consideration to the evidence in this matter leads me to conclude that:

1. Disco can and should use the existing billing data to sub-divide or rearrange their customer classifications so they provide a better match to cost causation and facilitate rate design, and
2. Disco should not be ordered to develop and file a seasonal rate proposal with their next rate filing.

My reasons are as follows.

Item 1. Customer class sub-division/reclassification.

The evidence presented in the hearing clearly established that Disco's peak load occurs during the winter months. This peak load is generally acknowledged to be a significant determinant of a utility's cost of service; Disco structured the cost allocation study to reflect this premise, and no intervenor took issue with it.

Disco's billing determinant records for the 5 fiscal years ending March, 2005 were also in evidence during the hearing. These consisted of data files organized with one line of data (case) for each bill sent. Each case record contained the energy billed, the number of days the bill represented, the meter reading and invoice dates and a unique customer identification number. Demand data was also included for those customers with such meters.

The data are voluminous, on the order of 20 million billing records, and require analysis to gain useful insight to their implications for cost-allocation and rate design. Neither the applicant nor any intervenors made such an analysis, however, leaving the Board to its own devices in making inferences or drawing conclusions from the data.

My own examination of the billing data, made using standard analytic techniques, leads me to conclude that Disco's current rate structures and customer classifications do not result in a fair and equitable sharing of the costs of service between Disco's customers. This conclusion is based on an examination of each customer's average January bill – the month in which Disco generally experiences peak demand -- and the ratio of that bill to the same customer's average bills in July and August, the season of minimum loads for Disco. Grouping customers with similar January loads and similar winter-summer load ratios and comparing those groups to Disco's existing classifications reveals two significant facts. These load and load-ratio based groups of customers:

1. Cut across Disco's existing residential, general service, and industrial classes, and
2. Sub-divide Disco's existing classes.

These facts must be weighed along with the substantial body of undisputed evidence that Disco's cost of serving customers varies with the season of use. Taken together, they lead to the conclusion that Disco's existing customer classification works to frustrate the fundamental regulatory objective of setting fair and equitable rates.

This conclusion is not, in itself, a sufficient basis for finding Disco's rates and charges unfair or inequitable. A set of rates could, in theory, overcome this problem by careful design and application. In my view, the burden of proof for such careful design and application properly rests with the applicant.

Unfortunately, the evidentiary record provides scanty evidence for any claim that Disco's proposed rate design overcomes this problem. In fact, Disco subdivided the residential class into customers that it infers use electricity for space heating and those who do not, and found different costs-of-service and revenue/cost ratios for each group. In doing so, Disco implicitly acknowledges that their current rate schedule does not compensate for the shortcomings of their classification method. While Disco's particular choice of sub-groups resulted in revenue/cost ratio differences that it proposes to be acceptable, it offers no evidence that their proposed sub-division is either the only one evident in the class or the best of several that may be evident from an examination of their customer's usage characteristics.

Figure 1 presents one set of subdivisions of the billing data from the fiscal year 2005. Only residential customers were selected for presentation because this issue arose in deliberations pertaining to the desirability of removing certain types of customers from the residential class. As noted above, these sub-divisions were also found to contain general service and industrial customers.

Figure 1 reveals 4 main types of customers:

1. Those with flat load profiles or little variation over the year,
2. Those with summer peaking loads,
3. Customers with winter peaking energy use, and
4. Dual-peaking customers, with relatively greater energy use in both summer and winter.

The 3rd group is clearly also divisible by the degree to which their load varies throughout the year. Some such customers have summer loads that are about 60% of their January consumption; others provide summer loads less than 10% of that value.

Considering the obvious seasonal variation of customer use profiles within the existing classes, the clear evidence that such variation has a significant impact on the cost of service, and the lack of evidence that the current classifications and rate structure can allocate cost to customers on a fair and equitable basis, I would direct Disco to:

1. Subdivide their current customer classes, discriminating between sub-groups of customers using:
    a. January energy consumption, properly adjusted for weather variation from long-term normal conditions and billing period variations; and
    b. The ratio of each customer's January energy consumption to their consumption in the summer;
2. Develop rate designs and/or rate parameters for each such sub-division, such that no sub-division or member of a sub-division experiences a revenue/cost ratio outside the range of 95% to 105%, as determined by cost allocations based on:

a. The number of customers in each subdivision for allocating customer costs;

b. The January energy load of each customer for allocating demand costs in the absence of demand metering, and the demand-metered load adjusted by a suitable contribution factor where demand meters are installed;

c. The base load energy used, as indicated by the summer month electric energy use as a fraction of Disco's total summer month electric energy load; and

d. The "shoulder" electricity used, this being the electricity derived from other than base-load plants, and as indicated by the difference between their total annual electricity consumption and that which is obtained by multiplying their minimum month's electricity consumption by 12.

3. Examine the effective rate increase for each customer that results from the sub-division of classes and cost allocations described above. Where the resulting rate increase results in rate shock for any customer, the rate design and/or parameters should be adjusted to limit the increase to an acceptable value.

4. Disco should recover any revenue shortfall that results from Item 3. (capping the rate increase at an acceptable value) from the capped customer's sub-class. No revenue recovery should be made from outside a sub-class until each member of the sub-class that is deficient in revenue has reached the rate cap. Revenue recovery, both within a sub-class and between subclasses, should be made on the basis that no customer or class that would properly receive a decrease in rates should be required to contribute to the recovered revenue unless and until every

sub-class and customer that would properly receive a rate increase has had that increase adjusted to the cap. Allocation of recovered revenue between members of a sub-class containing rate-capped customers should be made on the basis each customer's proximity to the cap; *i.e.* revenue recovery should start with the customer closest to and below the rate-cap, result in their being moved to the rate cap, and then proceed to the next closest customer, until the revenue shortfall is eliminated or the entire class is at the rate-cap.

While I remain open to further evidence and argument about the details of these directions, I am convinced such or similar work should form the basis of any rates decided by this Board. Having developed sub-classes as described above for the purposes of examining the billing data, it is clear to me that it is reasonable that Disco be asked to do so in the time available. Further, having used such sub-classes to examine the allocation of revenue under the current residential rate structure, I find that the existing classifications and rates fall outside reasonable bounds for fair and equitable treatment of customers.

While I understand and appreciate that Disco can, and will, achieve a better sub-division of classes and allocation of costs when it has the results of a suitable load research program, and agree that they should be ordered to do such research, I find sufficient evidence in the record of the hearing to justify ordering immediate action to adjust classifications and rate designs that are clearly unfair to many customers and provide inappropriate price signals to electricity users.

Item 2. Order to develop seasonal rates.

I also disagree with my colleagues' order that Disco prepare and submit a proposal for a seasonal rate at the time of their next application. My review of the billing data suggests that Disco should forego the development of any seasonal rate structure until is it determined that such or like sub-division of customer classes as described above cannot meet the goals of fairness and equity and simultaneously provide suitable pricing signals to customers. Any such determination should be made by this Board, and Disco should be required to make a comprehensive examination of available rate and tariff structures, including energy metering with demand subscription, non-coincident and coincident demand metering, time-of-use metering, and real-time rates before proposing any seasonal rate. Any seasonal rate proposed by Disco should apply to all customers exhibiting similar seasonal variation in their loads.

Dated at Saint John, New Brunswick this 21st. day of December, 2005.

Ken Sollows,
Commissioner

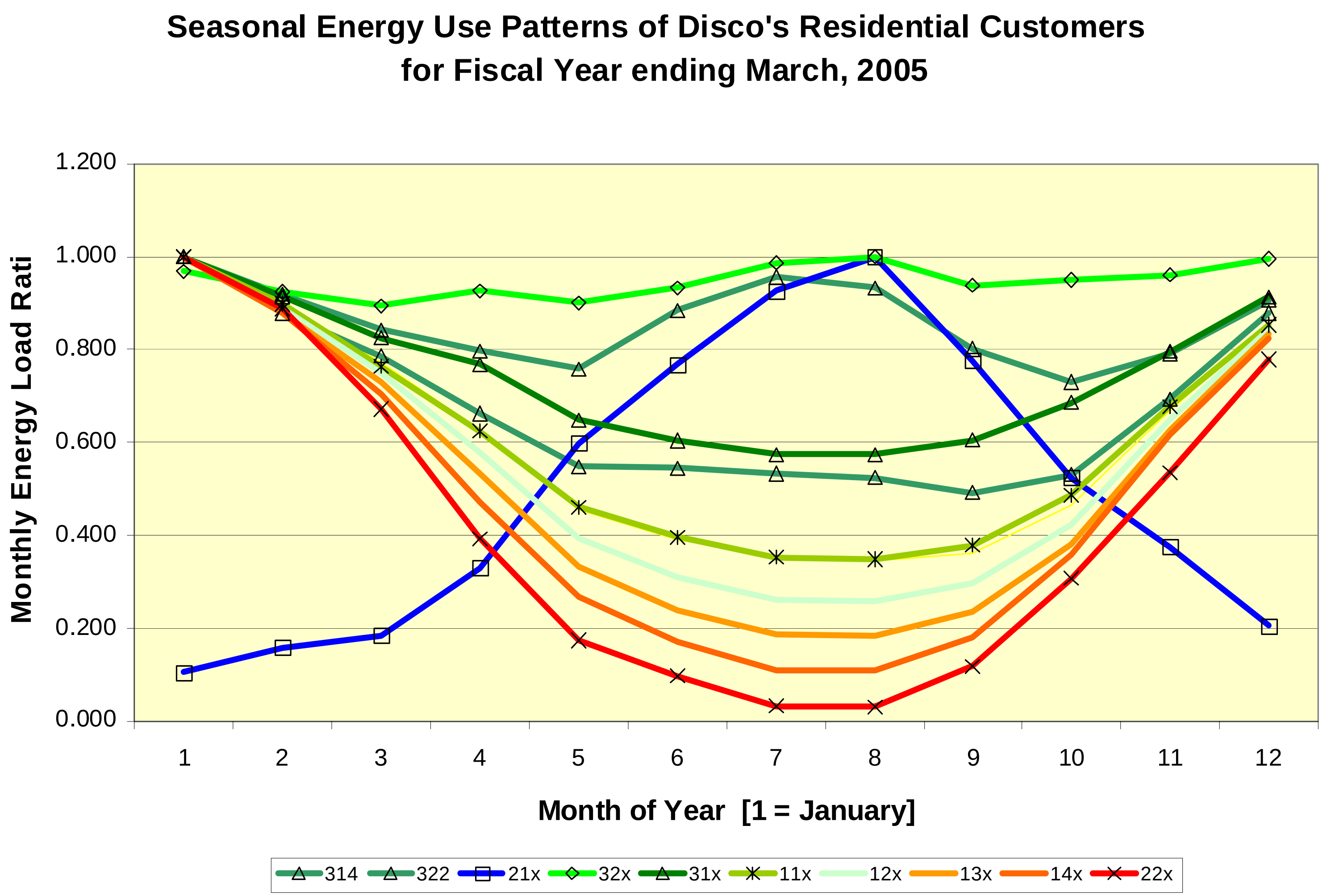

Figure 1 Residential customer seasonal electricity use patterns for fiscal year ending March, 2005