Manitoba Hydro Book of Documents #2

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TAB 1

Principles of Public Utility Rates

by JAMES C. BONBRIGHT

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THE PHILOSOPHY OF MARGINAL-COST PRICING

With only minor exaggeration, this entire book may be viewed as an attempt to play variations on a main theme first expressly set forth in Chapter III, "The Role of Public Utility Rates." This theme runs to the effect that utility rates, like other prices, are designed to perform multiple functions as instruments of economic control. To a high degree, these functions can be performed in harmony; necessarily so, indeed, since they are partly complementary. But the harmony is far from complete, for the most efficient performance of any one function would require the acceptance of a system of rates not also best designed to perform any of the others. In consequence, one of the most frustrating problems of rate theory and of practical rate making is that of suggesting and applying principles of workable compromise.

Among these conflicts of rate-making objectives, one of the most serious is that between the usually accepted principle that the rates of any public utility, in the aggregate, should cover its total costs of service, including fixed charges or a "fair return," and the also widely approved principle that specific rates should be based on the costs of specific amounts and types of service. For reasons stated in Chapter XVI, these two goals of rate-making policy are incompatible except under a somewhat rare coincidence in corporate operation and finance. In the absence of such a coincidence, any attempt to attain them both completely would be as hopeless as would be an attempt to draw a square circle.

How has rate-making practice undertaken to face this dilemma? In the main, except when circumstances have made the gap be-

tween the two objectives too wide to jump, it has done so by a somewhat qualified grant of priority to the first goal—that of a level of rates adequate for financial self-sufficiency. Even here, cost-of-service criteria of specific rates and rate relationships have received "due consideration." But these criteria have been relegated to a subordinate position, yielding precedence to the total-cost standard partly through overt deviations of a value-of-service nature, partly through loose "interpretations" of cost of service in terms of ill-defined and arbitrary "fully distributed" costs rather than in terms of differential or incremental or marginal costs.

Accepting, at least for the purpose of discussion, the traditional priority of the full-cost-coverage goal of rate-making policy, the four preceding chapters have considered methods of rate differentiation designed to permit the attainment of this goal with the least harmful departures from the principle of specific cost pricing. These methods include the limited but substantial resort to price discrimination. But while, under most conditions, their skillful application may bring about a reasonable degree of harmony between the two above-noted criteria of a sound rate structure, the results are bound to be far from ideal. Indeed, in some situations, including those now faced by the American railroads and, possibly, by the natural-gas industry, the results may become almost intolerable.

Impressed with both the theoretical and practical difficulties of any attempt to secure a sound structure of individual rates subject to the constraint that rates as a whole must cover costs as a whole, one important group of modern economists has proposed to seek riddance from this constraint. Let all rates be set at marginal costs. But if the resulting revenues should fall short of meeting total financial requirements, let the deficiency be made good by a tax-financed subsidy. On the other hand, if the total revenues should prove excessive, as they may well do if current unit costs of additional plant are far in excess of the unit costs of the existing plant, let at least a large part of the excess be recaptured by the community or by the nation through special taxation or else through outright public ownership.

What these economists here propose is a narrowing of the role of public utility rates as instruments of economic control. Relieved of any obligation to supply whatever funds may be required in order to maintain the credit of the enterprise as a going concern, rates can now be designed as single-purpose, precision instruments by which to control the demands of consumers for services of different kinds and in different amounts.[1] Even here, to be sure, rates will play an ancillary role in helping to finance the enterprise. But they need no longer be tailored with this subsidiary function in mind, since their deficiencies in this respect can be made good by another powerful instrument of economic control—that of taxation.

We may restate this proposed limitation of the role of public utility rates by saying that these rates should be called upon to perform only those functions which they will perform when designed as if their sole purpose were to control the effective demand for the services. But an even more restricted role is contemplated by those more thoroughgoing marginalists whose view will be set forth in the next section. For, in their concern to use utility rates as devices by which to secure the optimum utilization of an *existing* utility plant, however excessive or deficient may be its present capacity in relation to the potential demand for its services, they would apply a *short-run* measure of marginal costs—a measure which may seriously detract from the usefulness of rates in the determination of the demand for and supply of utility services over extended periods of time.

Before turning to the basic philosophy of marginal-cost pricing, we may comment briefly on its recent history.[2] The underlying idea is by no means new and is derived from the well-known principles of competitive-price determination developed in England by Alfred Marshall and other "neoclassical" economists of the late nineteenth century.[3] Under perfect competition as de-

[1] A French authority on marginal-cost pricing writes: "Vu sous ce jour, le prix n'a pas pour objet de rémunérer les dépenses du producteur au nom d'un quelconque principe d'équité, mais de motiver les décisions à venir des consommateurs de telle manière que celles-ci ne causent pas dans l'économie de dépenses irrationelles." M. Boiteux, "La Tarification des demandes en pointe: Application de la théorie de la vente au coût marginal," 58 *Revue générale d'électricité* 321–339 at 323 (1949).

[2] This history down to 1950 is well presented by Nancy Ruggles, "The Welfare Basis of the Marginal Cost Pricing Principle," 17 *Review of Economic Studies* 29–46 (1949–1950); "Recent Developments in the Theory of Marginal Cost Pricing," *ibid* 107–126.

[3] But Hotelling, in an article cited in footnote 6 below, gives to a French engineer, Jules Dupuis, the primary credit for developing the principle in its application to

fined by these economists, the prices of all products "tend" to come into equality with their average unit costs of production, in that such an equality is one of the conditions of static equilibrium. But these prices also "tend" to equal marginal costs, both of short-run and of long-run varieties. There is no inconsistency among these multiple conditions of equilibrium as long as the products in question are produced at unit costs that either stay constant despite a change in the rates of output, or else increase with increases in output.[4] But if any product should be produced under a condition of *decreasing* unit costs, the maintenance of perfect competition is impossible.

Public utilities belong to a group of industries which are supposed to operate under the latter condition, at least in the typical case—a fact often cited as accounting for the need for their regulation as a substitute for competition. But the very condition which rules out actual competition also rules out any attempt to secure by regulation *all* of the good attributes of competitive prices including those of an equilibrium position in which prices are simultaneously equal to a whole variety of costs including average total costs, short-run marginal costs, and long-run marginal costs.

As already indicated, public opinion, insofar as it has been made aware of the very existence of the dilemma between a full-cost principle of competitive pricing and a marginal-cost principle, has tended to accept the former principle and to reject the latter. Indeed, until well into the twentieth century, the wisdom of this choice was not seriously challenged, head on, by the professional economists, most of whom accepted for public utility services, as for commodities in general, the traditional precept,

public works: "De la mesure de l'utilité des travaux publics," *Annales des ponts et chaussées*, 2nd Series, Vol. 8, 1884. An English translation appears in No. 2 *International Economic Papers* 83–110 (1952).

[4] One might suppose that, if a firm is producing under conditions of increasing unit cost, marginal costs will *exceed* average costs. And so they may if the average costs are an average of total costs defined and measured as a regulating commission would do for purposes of determining corporate revenue requirements under a fair-return standard of rate making. But under the theory of a competitive price, the total costs of production are defined as the costs to an enterpriser who must buy or rent all of his factors of production, including land sites, water rights, rights to use the public streets, etc., in a current, competitive market. In consequence, any excess earnings which might otherwise go to the enterpriser because of an ability to sell his product at a marginal cost in excess of average cost are obligingly gobbled up by landlords and by other recipients of rents or quasi rents.

"Let the beneficiaries bear the burden." Objections to this standard of financial self-sufficiency, while not completely ignored, were met with proposals for "practical" solutions, such as that for a type of rate base which hopefully would bring the average total costs of public utility services within a tolerable range of long-run marginal costs; [5] or such as that for the adroit use of rate discrimination designed to bring down toward marginal costs the charges for those classes and quantities of service for which the demand is *unusually* responsive to changes in price.

In 1937, however, this cautious—some writers would even say timid—attitude of the academic economists was sharply challenged by Professor Harold Hotelling, then at Columbia University, in one of the most brilliantly written articles in the history of utility rate theory.[6] In a sense, the economic philosophy of this article was orthodox in that it accepted a competitive-price rather than a "social-value" standard of rate making. But in another sense it was heretical, in that it regarded the marginal-cost attribute of a competitive price as more important for the purpose at hand than the average-cost attribute. This unconventional preference was based largely on the belief that the price system is almost uniquely qualified to perform the function of resource allocation or consumer rationing with maximum efficiency, whereas, in a regulated monopoly operating under conditions of decreasing cost with increasing output, it is not well qualified to perform the other functions of a competitive price (those other functions set forth in Chapter III, on the role of public utility rates) except in an auxiliary manner.

Both in this country and in Europe, Hotelling's thesis soon attained fame among the academic economists and led to a substantial flow of monographs and articles, some supporting his position and some defending the traditional principles of "full-cost" pricing.[7] The number of his *unqualified* supporters has been

[5] See p. 230, n. 7, *supra*, referring to an early debate between Professor Harry Gunnison Brown and myself on the relative merits of an original-cost or a reproduction-cost rate base.

[6] "The General Welfare in Relation to Problems of Taxation and of Railway and Utility Rates," 6 *Econometrica* 242–269 (1938). See also his later note, replying to Professor Ragnar Frisch, on "The Relation of Prices to Marginal Costs in an Optimum System," 7 *ibid.* 151–160 (1939). Hotelling had presented his main thesis at a meeting of the Econometric Society in December, 1933, though I believe not with his newer mathematical proof of its validity.

[7] See the articles and books noted by Nancy Ruggles in her previously cited re-

very small. But this fact by no means belies the significance of his contribution to the theory of public utility rates. For he has substantially influenced the development of this theory, even on the part of those writers who still insist that "rates as a whole should cover costs as a whole."

It is a most disturbing commentary on the lack of communication in America between writers on the economic theory of public utility rates and persons engaged in the actual practice of rate making or rate regulation that few of these latter persons are familiar with, or interested in, the philosophy of marginal-cost pricing. Partly in the hope of bringing this philosophy to the attention of the practitioners, I close this book with the following elementary exposition and appraisal.

SHORT-RUN MARGINAL-COST RATE MAKING

For reasons already stated in Chapter XVII, the significance of the distinction between marginal-cost and average-cost pricing is far greater when the former alternative is taken to mean pricing based on *short-run* marginal cost than when it is taken to mean pricing based on a persistent or chronic or *long-run* marginal cost. While the broad distinction is significant even under the latter interpretation, it is revolutionary only under the former. We shall therefore first consider the case for marginal-cost pricing in its former, uncompromising sense—the sense accepted by Hotelling. A technical treatment of its rationale would be an elaborate procedure, involving mathematical analysis based on a host of simplifying assumptions. But a general idea of the argument in its favor is easily presented—all the more so here since it is implicit in the more familiar acceptance of "out-of-pocket cost," the popular version of marginal cost, as a measure of *minimum* rates.

By way of illustration, let us borrow Hotelling's example of a very simple type of public utility plant, that of a toll bridge for motor vehicles. The bridge, let us say, is owned and operated by a public authority, which has financed its construction by the sale

view (footnote 2) of the literature. Compare, e.g., the defense of full-cost pricing by Professor R. H. Coase with the qualified support of marginalism by Professor William S. Vickrey: Coase, "The Marginal Cost Controversy," 13 N.S. *Economica* 169 (1946); Vickrey, "Some Objections to Marginal-Cost Pricing," 56 *Journal of Political Economy* 218 (1948). For a significant book on the subject by a socialist economist, see Burnham P. Beckwith, *Marginal-Cost, Price-Output Control* (New York, 1955).

of revenue bonds. In line with the traditional principle that public utility rates must cover total costs, the toll must be set at the minimum deemed necessary to pay the annual maintenance costs of the bridge plus fixed charges, which are here composed of interest charges plus amortization. Ignoring for simplicity the limited possibilities of differential tolls, let us assume that the required toll is $1 per crossing. This toll reflects the average total cost of the service.

Now let us note the economic harm done by this orthodox attempt to base utility rates on the financial principle that "every tub should stand on its own bottom." Assume, first, that the bridge has a capacity at least sufficient to accommodate all traffic forthcoming on a toll-free basis. On this assumption, the levy of the $1 toll is economically unsound, since its deterrent effect will prevent the bridge from being put to its fullest feasible use. Indeed, on the only slightly inaccurate assumption that even the maintenance costs of the bridge will not be affected by the amount of use, the imposition of any toll whatever is unsound.[8] All of the costs being "sunk costs," they should have been paid for, directly or indirectly, entirely by taxation, just as are city streets and sidewalks.

But what about the situation that will probably arise, sooner or later, when the bridge traffic, especially if stimulated by freedom from tolls, threatens to become too congested for safe handling by the present bridge? When this time arrives, a toll should be imposed. But the amount of the toll should be in no way determined or limited by the authority's financial needs. Instead, it should be made high enough to preclude serious traffic congestion by limiting the use of the bridge to those persons who are ready to pay the potential "market-clearing" price for this use. In an extreme situation in which an unexpected or unprovided-for growth in potential demand for river crossings makes the present capacity of the bridge grossly inadequate, a toll as high as, say, $10 might well be required. This toll should be removed completely if and when a later enlargement or duplication of the bridge again makes the capacity redundant.

[8] This statement requires qualification since it makes the simplifying assumption that, up to some definite point of "serious traffic congestion," the quality of the bridge-crossing service remains unaffected by the traffic. In fact, however, this quality, as measured by speed, comfort, and safety, will deteriorate gradually with increases in traffic, since each additional driver will get in the way of other drivers. As long as the bridge remains toll free, every user therefore imposes a cost upon other users which he is not required to defray. This means that the marginal *social* cost of bridge service then exceeds the cost imposed upon any one user. In theory, there should be a toll sufficient to deter use of the bridge by anyone to whom the value of the service is not sufficient to warrant the extra traffic congestion which he imposes on other users. See a much cited discussion of this point by Professor Frank W. Knight, taking issue with a position previously held by Professor Pigou: "Some Fallacies in the Interpretation of Social Cost," 38 *Quarterly Journal of Economics* 582–606 (1924), reprinted in Knight, *The Ethics of Competition* (New York, 1936). The subject is very important in the field of highway-transportation economics and, as will be noted later, has an important bearing on rate-making policies for local transit. See Martin Beckmann, C. B. McGuire, and Christopher B. Winsten, *Studies in the Economics of Transportation*, a series of studies for the Cowles Commission (New Haven, Conn., 1956). Telephony presents a situation reverse from that here mentioned in that the addition of another telephone subscriber may *add* to the "value" of the service enjoyed by the other users.

But would not the imposition of this market-clearing toll violate the very principle of marginal-cost pricing which Hotelling has advanced as a general substitute for pricing based on average total cost? The answer is no, although the definition of "marginal cost" must here be extended so as to give it a relevant meaning without sacrifice of its economic significance. For, if the bridge traffic has now reached its uppermost limit, the marginal social cost of permitting any one vehicle to use the bridge is measured by the value of the opportunity of use that must be denied to the highest excluded bidder. This bidder is the potential user who is barely deterred by the obstacle of the $10 toll. In other words, the relevant marginal cost, instead of being a production cost, is here an exclusion cost as measured by the marginal value of the service.

Later writers have elaborated on Hotelling's bridge illustration by noting the "economic distortion" that may result from the imposition of different tolls on different bridges or highways designed to meet separate tests of financial self-sufficiency, project by project.[9] Where optional routes are available for trucks and passenger cars, the resulting mixture of high-toll, low-toll, and no-toll routes is almost sure to lead to serious economic wastes, because it motivates the road users to base their choices on relative money costs that do not reflect relative social costs.

But the toll-bridge illustration is merely a simple example of the asserted advantages of marginal-cost pricing over full-cost pricing applicable to all public utilities—applicable, in short, to a

[9] Particularly William S. Vickrey, "Some Implications of Marginal Cost Pricing for Public Utilities," 45 *American Economic Review, Proceedings* 605–620 (1955). Professor Vickrey has become the leading American authority on marginal-cost pricing in its application to public utilities.

vitally important group of noncompetitive industries with respect to which the gap between the two types of pricing is especially wide and especially menacing. To be sure, marginal costs even of a short-run variety are less likely to be merely trivial for these other utilities than for toll bridges. Moreover, opportunities for rate discrimination as a means of full-cost recovery are likely to be much better. But the general principle still applies. And, as to the use of discrimination as a device by which to jump the gap between average-cost and marginal-cost standards, Hotelling cites some unhappy consequences of the attempts by railroads to make these jumps as failing to justify any complacency toward this device for the attainment of essentially inconsistent advantages.

In recent years, many railroad properties, including rights of way, tracks, and passenger terminals, have become redundant as a result of the growth of competing forms of transportation, combined with technological progress in signalling, etc., with respect to main line hauls. This redundancy, moreover, may last for a long time—some of it as long as the structures remain standing. Meanwhile, attempts to put the existing properties to their best available use are seriously handicapped by the largely hopeless attempts of the railroads to secure a "fair return" thereon and by the pressure upon the Interstate Commerce Commission to sanction rates designed to yield such a return.[10] Professor Hotelling's proposal would meet this situation by a general reduction of railroad rates to short-run marginal costs. This reduction would apply to entire railroad rate levels instead of being confined to a discriminatory and distortionate reduction of those particular rates that must be reduced in order to meet the immediate and direct competition of the road and water carriers. Any resulting fair claims by railroad investors for restitution for this retroactive change in rate-making policy would be cared for, presumably, by a government-financed indemnity.

[10] The seriousness of the handicap can be appreciated when one recognizes that, if a railroad or utility company were entitled to annual changes in rate levels designed to yield a stable "fair rate of return" on the net investment in, or so-called value of, its property, year after year, it would need to raise rates during years of depression and lower them during years of prosperity—a viciously cyclical procedure. Indeed, the Interstate Commerce Commission actually gave the railroads permission to make emergency rate-level increases in the depression period of the 1930s. Marvin L. Fair and Ernest W. Williams, Jr., *Economics of Transportation*, rev. ed. (New York, 1959), p. 576.

CRITIQUE OF PROPOSAL TO FIX RATES AT SHORT-RUN MARGINAL COSTS

Reserving for a later section a discussion of the much milder proposal to base rates on marginal costs of a long-run character, let us now consider critically the merits of the far more drastic proposal to base rates on short-run marginal costs.[11] Already some of the more serious objections have been noted in Chapter XVII, which discusses the relative merits of the two major types of marginal costs as measures of *minimum* rates.

First, let us recall that, with most public utilities, the really significant choice is not a simple choice between *marginal* cost and *average* cost as the basis of rate making. To be sure, the assumption that the rate maker faces this dire dilemma is not too far from reality in the toll-bridge example, since here the practical opportunities for rate differentiation are severely limited. Hence the bridge example presents an unusually forcible case for the adoption of marginal-cost pricing or, at least, for the abandonment of any attempt to make each particular bridge rest on its own financial foundations. But with railroads and most other utilities, there exists a wide variety of plausible rate structures, including those which resort to multi-part rate making, block rate making, and various forms of discriminatory pricing. Most of the rate structures now in effect are subject to material improvement with advances in the technique of rate design but without abandoning the total-cost principle. While none of them can be expected to have *all* of the consumer-rationing advantages of unqualified marginal-cost pricing, neither can they be assumed to result in economic losses of the order of magnitude of those suggested by an attempt to make a particular toll bridge financially self-sufficient through a uniform charge of so many cents or dollars per vehicle per crossing. Unfortunately, however, the measures of the relative gains and losses of marginal-cost pricing versus any given type of discriminatory, full-

[11] For one of the most well-balanced critical appraisals of marginal-cost pricing, both of the short-run and the long-run varieties, see Robert W. Harbeson, "A Critique of Marginal Cost Pricing," 31 *Land Economics* 54–74 (1955). Harbeson comments on one criticism not discussed in this brief chapter: that the supporters of marginal-cost pricing for regulated monopolies ignore the supposed failure of unregulated prices to come into accord with marginal costs under the most widely prevailing types of competition, namely, "imperfect" or "monopolistic" competition.

cost pricing that are suggested by economic theory are impossible to apply in terms of present factual knowledge.

Secondly, we must consider whether or not the almost undeniably superior efficiency of short-run marginal-cost pricing as a means of securing the optimum utilization of a plant of temporarily redundant capacity [12] warrants the surrender or impairment of all of the other important functions of utility rates, even the function of aiding in the control of the demand for and supply of utility services in the longer run. By and large, the major influence exercised on consumer demand for utility services by any current rates of charge for these services is an influence based on the expectation that these rates indicate, at least in a general way, the rates that will remain in effect over a considerable period of time. For it is the anticipated, fairly long-run costs of service which a potential consumer wisely takes into account when he faces a decision whether to commute from New Jersey to New York despite the daily payment of tolls on the George Washington Bridge; or whether to equip his home with an electric range or with electric space heating; or whether to locate his aluminum plant on the St. Lawrence River rather than in the state of Washington. Once having become dependent on the services required for the operation of expensive complementary equipment, the consumer's responsiveness to temporary changes in rates of charge will probably be very limited. In short, the price elasticity of demand for utility services can be expected to be much greater in the fairly long run than in any very short period of time. But if utility rates were to be made as volatile as would be required by the mandate of conformity to short-run marginal costs, they would deprive consumers of those expectations of "reasonable continuity" of rates and of rate relationships on

[12] Even this claim of superiority must be conceded only on the assumption that the better-than-nothing use of temporarily excess capacity will not materially interfere with possible emergency use. Instant readiness to serve may well be the best use of idle capacity. Professor Eli W. Clemens had this point in mind in doubting the wisdom of proposed attempts by electric utilities to encourage three-shift factory loads by the concession of very low rates for off-peak industrial service. 23 *Southern Economic Journal* 91–93 (1956). Resort to three shifts, he recalled, was one of the major ways by which the country avoided a menacing power shortage during the Second World War. "One day's loss of lives," he added, "constitutes quite a lot of marginal disutility." To the same effect, see Emery Troxel, "Reserve Plant Capacity of Public Utilities," 26 *Land Economics* 145–161 (1950), quoting at p. 150 from a significant book by the South African economist, Professor W. H. Hutt, entitled *The Theory of Idle Resources* (London, 1939).

which they must rely in order to make rational advance preparations for the use of service.

Thirdly, and closely related to the objection just mentioned, there is the probability that short-run marginal-cost rate making would deprive utility managements of an almost essential guide to intelligent decisions as to the needs for plant expansion. Under prevailing systems of rate making, managements base their estimates of future service requirements on a projection of past growth trends in the consumption of different classes of service. Their provisional assumptions that these same trends will persist in the future are premised on the expectation, not necessarily that rates will stay fixed, but at least that they will remain in fairly stable relationship to the prices of other products. But if current rates were to rise and fall with changes in current marginal costs, the resulting unpredictability of future demands might seriously handicap managements in timing their programs of construction.[13]

In his defense of short-run marginal-cost pricing, Professor Hotelling argued that the construction and expansion of public utility plants and of other public works are seriously retarded by the traditional and fallacious assumption that the economic justification of a proposed project depends on a finding that it can be made to yield revenues at least sufficient to cover its total operating and capital costs. This assumption, he declared, ignores the failure of the anticipated revenues to reflect those benefits that will accrue to consumers in the form of "consumers' surplus"—benefits measured by the excess in the highest prices that consumers would be willing to pay for different amounts of service rather than go without, over the prices that they will be required to pay under any feasible system of more or less uniform prices. While this point certainly suggests a complicating factor in a cost-benefit analysis of a large public-works project, it is not a convincing argument for the gen-

[13] But my colleague Professor Vickrey, who has kindly read this chapter in manuscript, disagrees sharply. "Far from making the timing of construction more difficult," he writes, "fluctuating rates would provide an instrument whereby demand could be adjusted to supply, so that the consequences of an unexpectedly large surge in demand, or failure of supply due, say, to drought, would be much less disastrous. Therefore a much smaller margin of excess demand to protect against these contingencies would be necessary. At the other end of the scale, excess capacity provided by overoptimistic planning would be utilized more fully so that mistakes in this direction would be less wasteful also. Compare Ontario Hydro in the depression." I have cited the Ontario Hydro experience in an earlier chapter, p. 335, *supra*.

eral abandonment of a financial self-sufficiency test of utility plant expansion. For, if consumers' surplus is to be included in a calculation of the benefits derivable from any proposed expansion, then it must also be included on the cost side of the cost-benefit balance sheet, in the estimate of the "opportunity costs" of public utility plant construction—costs which may include the withholding of economic resources from the construction of plants designed to produce other products, the sale of which would also yield a consumers' surplus.[14]

In the fourth place, we must consider the question whether the claimed advantages of short-run marginal-cost pricing as a means of improving utility rate structures, even if substantial, would still be great enough to warrant the required resort to tax-financed subsidies. The most popular objection to subsidies is based on the declared unfairness of a system of rates which requires non-consuming taxpayers to subsidize the beneficiaries. But quite aside from any such considerations of income-distributive justice, there are serious political objections to wholesale extensions of public subsidies: namely, that legislative grants of subsidies come so largely through the efforts of pressure groups and of regional interests which are under little impulse to weigh the benefits to themselves against the costs to other people. Even so, of course, many subsidized public projects will be justified, since many of them will have great social value even though their benefits are not of the type that can be made vendible except, perhaps, to a limited degree. But a general proposal to bring the country's railroad and other public utility systems into this category for the sake of the possible benefits of short-run marginal-cost pricing seems to me too portentous politically to deserve favorable consideration.

Finally, and apart from any general objections to a scheme of rate making which taxes nonbeneficiaries for the benefit of the beneficiaries, there is another reason for a refusal to impose upon

[14] The traditional cost-benefit analyses of public-works projects by the U.S. Corps of Army Engineers and the other government agencies include no allowances for consumers' and producers' surpluses as such, although they take account of the same phenomena in their estimates of indirect benefits. A pioneering study of public-project evaluation by Otto Eckstein seems to support the conclusion that, on the whole, the traditional analyses follow techniques tending to result in over-optimistic conclusions as to the ratios of benefits to costs. *Water-Resource Development* (Cambridge, Mass., 1958). See also John V. Krutilla and Otto Eckstein, *Multiple Purpose River Development* (Baltimore, 1958).

the country's existing tax system a part of the burden now borne with only moderate efficiency by its price system. This reason is that the only forms of taxation still available to carry the extra load are of a highly imperfect nature, with the result that the additional taxes might have more serious repressive or distorting effects on the nation's economy than full-cost-recovery rate making has on the outputs and prices of utility services. In his article in 1938, Hotelling recognized this danger and proposed to meet it by the use of certain taxes arguably not subject to shifting, such as taxes on land-site values, inheritance taxes, and income taxes. But in view of the critical subsequent rise in the nation's tax burdens, any hope of finding additional sources of public subsidies in the form of yet unused taxes that are "neutral" in their effect on the allocation of the country's economic resources seems extremely remote. Certainly neither the corporate nor the individual income tax could any longer be regarded as such a source. The most promising alternative might well be the resort to a widely spread excise tax, such as a sales tax, the use of which would permit the reduction of the wide gaps between the rates and the marginal costs of utility services in exchange for a slight increase in the narrower gaps between the prices and the marginal-production costs of commodities and services throughout a much larger sector of the economy.[15]

THE ALTERNATIVE STANDARD OF LONG-RUN MARGINAL COSTS

One may summarize the foregoing criticisms of the proposal to base utility rates on short-run marginal costs by saying that, in giving sole consideration to one very limited though important function of prices, that of securing the optimum utilization of whatever plant capacity exists at a particular time, it would sur-

[15] The sales tax or some similar, widely applied, excise tax, once so largely opposed by economists in view of its regressive character, has regained status among many economists, who recognize the serious distortion effects of the current high income taxes and of other taxes of a designedly progressive nature. But in view of the nation's need to devote far more of its resources to nonvendible products of high social value, such as in public education, health service, and recreation—a need so persuasively argued by Professor John Kenneth Galbraith in his *The Affluent Society* (Boston, 1958), one may doubt the wisdom of resort to excise taxes in order to subsidize the production of vendible public utility services. Indeed, the mere cost of administering such taxes might offset whatever value they might otherwise have in securing a better allocation of resources.

render other functions of even greater importance including, particularly, that of the long-run control of the demand for and supply of utility services. Mainly for this reason, I take it, the proposal has won little support even from those economists who are most impressed with the shortcomings of full-cost standards of rate making.

But another version of the marginal-cost principle has enlisted more sympathetic interest among academic economists: the principle of rate making based on long-run marginal costs. As yet, at least, even this far milder version has made no appeal to the legislatures or rate-making practitioners of this country or of England. But on the European continent it has made some headway among the administrators of the nationalized railroads and utilities.[16] And in France the principle has already been put into partial application, particularly by the electric power system (Électricité de France).[17]

The basic distinction between short-run and long-run marginal cost has been discussed at length in Chapter XVII and need not be restated here. Advocates of either type of cost as a measure of reasonable rates accept, as the primary objective of rate-making policy, an optimum-allocation or consumer-rationing objective even if its realization calls for the surrender of the traditional principle of financial self-sufficiency. But the long-run marginalists emphasize the need for a relatively stable and continuous level or trend of rates, in the belief that the rates which have the most important effects on the demand for and provisions for utility services are rates that may be expected to persist over a considerable period of

[16] See *The Theory of Marginal Cost and Electricity Rates*, published by the Organization for European Economic Co-operation (Paris, 1958).

[17] See Thomas Marschak, "Capital Budgeting and Pricing in the French Nationalized Industries," 33 *Journal of Business of the University of Chicago* 133–156 (1960). The engineer-economists of these industries—notably Mr. Marcel Boiteux, Vice President in charge of economic studies, Électricité de France—have been in advance of any other writers in their contributions to the principles of rate making based on marginal cost. In addition to the articles cited in footnotes 10 and 21 of Chapter XVIII, footnote 25 of Chapter XIX, and footnote 1 of the present chapter, see Boiteux, "La Vente au coût marginal," *Revue française de l'énergie*, Dec., 1956; "Le Tarif vert d'Électricité de France," *ibid.*, Jan., 1957; "Les Tarifs de la concession d'alimentation générale d'E.D.F.," in a later issue of the *Revue* for 1957. See also Gabriel Dessus, "The General Principles of Rate-Making in Public Utilities," translated, *International Economic Papers*, No. 1, 5–22 (1951); Dessus and Fleurquin, "Les Tarifs de gaz et d'électricité et l'orientation du consommateur," 58 *Revue d'économie politique* 513–546 (1948).

time. Hence, the most important marginal costs for purposes of rate control are the normal or persistent marginal costs rather than the very short-lived marginal costs that may fall almost to zero in some brief period of time, only to rise to several times average total costs soon thereafter. For this purpose, however, "long-run" marginal costs must be given a flexible and frankly indefinite interpretation, since any attempt to fix rates today by reference to cost functions that may not materialize, say, for twenty-five years or more would be utterly foolish. In short, the costs that should be covered by the rates are the marginal costs that are "permanent" in the sense used by a dentist when he refers, optimistically, to a permanent rather than a temporary filling.

Although long-run marginal-cost rate making must rest its claim for acceptance primarily on its asserted superiority from the standpoint of optimum resource allocation, it has an important secondary advantage over the short-run alternative in requiring far less drastic departures from the orthodox requirement of full-cost pricing. As noted in Chapter XVII, this conclusion follows from the very definition of long-run marginal cost—a definition which treats all costs as varying with rates of output, even the so-called fixed costs. Indeed, with utility enterprises that have already attained the major economies of large scale, rates set at long-run marginal costs may be sufficient, or more than sufficient, to yield total revenue requirements. Under these conditions, the proposal to adopt marginal-cost pricing of the type now under review would not conflict with the maintenance of the traditional principle that rates in the aggregate must cover total costs. But down to the present time, both the theory and the practice of utility cost analysis are too primitive and too meager to supply an answer to the question how prevalent such conditions may be.[18]

The very reasons, however, which make the proposal to set utility rates at long-run marginal costs more "practical" than the proposal to adjust rates to short-run changes in marginal costs also constitute reasons for doubting its net advantages over full-cost

[18] In an unpublished study based on Interstate Commerce Commission data for 1936, the results of which he presented at the meeting of the Econometric Society in Montreal, Sept., 1954, Professor William S. Vickrey has estimated that, for American railroads as a whole, long-run marginal costs of freight service may well constitute from 75 to 80 per cent of average total costs. He notes that, as his study was based on cross-section comparisons at different actual densities of traffic, "it represents the extreme long-run end of the spectrum of marginal costs."

pricing as a generally applicable basis of rate control. Its best claim for serious consideration can be made in those situations in which the traditional attempt to make "rates as a whole cover costs as a whole" must be judged hopeless or intolerably wasteful in the light of experience. A verdict of this nature would almost surely apply to the city rapid-transit systems and may well apply to the entire American railroad industry, taken as a whole. The intercity railroads are vainly struggling to earn capital-attracting rates of return against the competition of heavily subsidized alternative forms of transport. Their chances of survival might be better if all of their rates, and not merely the rates for commodities or routes that face direct competition, could be brought down to levels set by standards of marginal costs over an extended period of time.

But one must not assume that marginal-cost rate making, whether short-run or long-run, offers a general solution of all of those rate-making problems raised by the inability of a utility to cover its full costs by the sale of its services. For there are many possible explanations of this inability other than the presence of a gap between marginal costs and average total costs. The local transit systems, for example, face competition from drivers of private cars, each of whom gets in the way of the others by adding to the traffic congestion. Under these conditions, subway fares should probably be set at less than marginal costs if the lower fare will serve to diminish congestion on the surface. A somewhat similar situation prevails on the railroads, which must compete with road and water users whose marginal private costs of using public highways and waterways understate the marginal social costs of maintenance and expansion. For these reasons, as well as for the reason that national-defense considerations may require the maintenance of railway facilities that are excessive for peacetime use, the marginal-cost-pricing philosophy of rate making is subject to important deviations in the direction of "social" principles of rate making.

MARGINAL-COST PRICING AND PUBLIC UTILITY TAXATION

Even though marginal-cost pricing may never win, or deserve to win, such widespread and unqualified acceptance as to supersede

the traditional principle of full-cost coverage for entire rate levels, it may nevertheless have increasing influence of an indirect nature as it gains in familiarity, in theoretical development, and hopefully in the prestige of successful partial application in France and elsewhere in Europe. One possibility—remote, I fear, for the immediate future—is that it may influence utility and railroad taxation in a downward direction. This possibility calls for a comment. But the comment will be brief, since the subject of taxation is far beyond the scope of the present book.

In a study made in the early 1920s,[19] Dr. Herbert D. Simpson of Northwestern University concluded that the history of American railroad and utility taxation could be divided into four stages. The first stage, which was in the development period of the canals, turnpikes, and railroads, was one of "reverse taxation"—of outright governmental subsidy. The second stage was that of complete or partial tax exemption. In this period, which ended around the middle of the nineteenth century, proposals to tax the railroads were regarded as "radical." The third stage was that of attempted uniformity of taxation—a uniformity that proved impossible to achieve because of the difficult problems of utility property-tax assessment. The fourth and final stage was that of special types of utility taxation, many of which discriminated harshly against the utility companies as compared to other taxpayers. Thus, said Dr. Simpson, "the pendulum in this field of taxation has swung from outright subsidy and exemption at one extreme, through the uniformity period, and over to high and discriminatory taxes at the other extreme."

When Dr. Simpson wrote, he believed that the time was ripe for a return to a policy of uniformity, although this uniformity might best be approached by modification of the special utility taxes rather than by the inclusion of utility properties under general-property taxation. And his view may well have reflected the general

[19] Manuscript of lecture on "Taxation of Public Service Companies" published in Herbert B. Dorau, ed., *Materials for the Study of Public Utility Economics* (New York, 1930), pp. 471–490. Professor Harold M. Groves divides utility-tax history into three periods: those of (a) subsidy, ending at the end of the nineteenth century, (b) neutrality, ending with the depression of the 1930s, and (c) "special burdens" from 1930 to date. *Financing Government*, 5th ed. (New York, 1958), p. 336. One tax expert whose name escapes me writes that public utility companies "are taxed, for the most part, as though the regulating commissions do not exist; tax authorities and regulators scarcely seem aware of their conflicting purposes."

trend of American tax philosophy at that time. But there soon took place a tendency to revert to discriminatory taxation. This tendency may have been stimulated by a growing belief that utility rate regulation, handicapped by the Supreme Court's current rulings on a "fair-value" rate base and by the growth of uncontrollable holding companies, was proving impotent to prevent utility companies from earning excessive profits. Taxation was therefore looked upon as a device by which to offset the shortcomings of regulation.

Since the Second World War, this excuse for high utility taxation has lost most of its force. But its place has been taken by the legislative recognition of the utility companies as unusually convenient and stable sources of revenue for hard-pressed government treasuries. Hence, utility services have been subject to special taxes, including excise taxes some of which are charged directly to the consumer, the others being charged to them indirectly through their inclusion as legitimate operating deductions whenever rates are readjusted by public service commissions.

At the present time, the sum total of local, state, and Federal taxes paid by the utility companies amounts to a substantial fraction of their gross revenues. For the private electric companies in the aggregate, this fraction was reported as 21 per cent in 1957 but came to 25 per cent or more for specific companies. For telephone companies the ratio of taxes to operating revenues has been even higher, on the order of 30 per cent. Typically, somewhat more than half of a utility's tax bill is for Federal corporate income taxes. But, under a rule laid down by the Supreme Court in the 1920s,[20] allowance for these taxes is also included in a commission's calculation of a company's total revenue requirements.

Assuming, as it seems plausible to assume, that this complex of utility taxes imposes a proportionately higher tax burden on the prices of utility services than nonutility taxes impose on nonutility commodities and services, there tends to result a misallocation of economic resources—an allocation of inadequate resources to the production of electricity, railroad transportation, etc. And, to the extent to which utility services are produced under conditions of declining unit costs, this discrimination compounds the shortcomings of a rule of rate making which requires a utility company to recover its total costs by charges for its various services. Indeed,

[20] Galveston Electric Co. v. Galveston, 258 U.S. 388, 399 (1922).

the most practical way to avoid or minimize these shortcomings may well be through tax discrimination in the opposite direction.

But important as is the likelihood that, on the whole, utility taxes are higher than they should be, relative to the taxes embodied indirectly in the prices of nonutility commodities and services, even more important is the high probability that these taxes discriminate against the supply of *particular types* of utility services. The most outstanding example of this situation is that in the field of transportation, where the heavily taxed railroads must compete with other, subsidized forms of transportation. As long as this situation of subsidy exists for road, water, and air carriers, sound economic policy dictates a closer approach to symmetry by the grant of complete or partial tax exemption to the railroads.

I close this book by raising one other serious question about utility taxation in its relation to rate-making policy. It concerns the marked differences between the high taxes imposed upon the private electric utilities of this country and the relative freedom from taxes or tax equivalents enjoyed by the electric plants operating under Federal, state, or local ownership. Needless to say, opponents of public ownership bitterly resent this tax differential. But even those who, like the present writer, favor a substantial but limited number of publicly owned electric systems, such as that of the Tennessee Valley Authority, cannot fail to be concerned with a tax situation that makes so difficult any fair comparison between private-plant and public-plant performance.

By all means the most desirable way by which to secure greater comparability of performance would be substantially to reduce, if not to eliminate, private utility taxation. But if the only politically feasible way to secure equalization is to raise the tax burden imposed on the services of the public plants, there then arises a dilemma, and the choice of the less seriously penetrating horn is not easily made.

In earlier years, when the country's great Federal hydroelectric projects were in their development stages, tax exemption of these projects seems to me clearly to have been the wiser choice. Today, when these public projects are now full-fledged going concerns, the issue is far less clear. There still remains one strong argument in favor of continued tax exemption: namely, that the country as a whole may benefit from the presence of a limited number of tax-free plants which can serve as experiment stations in developing and supplying the demand for power by means of promotional rates lower than those with which a tax-burdened enterprise can afford to experiment. The Tennessee Valley Authority's experience in the widespread promotion of a house-heating load may be of this nature. But when public plants receive a high tax advantage, whether for this purpose or any other, they lose much of their value as yardstick plants against which to measure private-plant performance. Moreover, freedom of public plants from the Federal taxation imposed on private utilities gives to public ownership a factitious advantage over private ownership, viewed from the self-interested standpoint of a local community, that must interfere with an unbiased appraisal of the relative merits of the two forms of organization from the standpoint of the nation. My present, tentative, opinion is that the weight of the argument favors attempts to put publicly and privately owned electric power systems more nearly on a par, tax-wise, by a combination of a heavier public tax load and a lighter private tax load. But this is not a book on public utility taxation or on public ownership, and the questions raised here demand thoroughgoing separate studies.

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TAB 2

Principles of Public Utility Rates

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PART FOUR

THE RATE STRUCTURE

In the introduction to Part Three we distinguished between the determination of a company's general level of rates, and the determination of specific rates or rate relationships. However, it was emphasized that the distinction between rate-level and rate-structure is one of convenience rather than of analytical logic. In the words of the late Chief Justice Stone (1942, p. 575, 584), speaking for the Supreme Court in *Federal Power Commission v. Natural Gas Pipeline Company*,

> The establishment of a rate for a regulated industry often involves two steps of different character, one of which may appropriately precede the other. The first is the adjustment of a general revenue level to the demands of a fair return. The second is the adjustment of a rate schedule conforming to that level, so as to eliminate discriminations and unfairness from its details.

Thus, the chapters of Part Three were concerned with rate-level determination under the standard of a fair return. Now we turn to a discussion of the far more complex problems involved in establishing an appropriate rate-structure.

The complexity of the rate structure is due partly to the mass of technical detail; this includes the rapidly advancing, but still constraining, technology of metering that is involved in the design and administration of workable rate schedules for different types of utility enterprises. It is also due to the inability of the ratemaker to predict the effects of changes in rates on the demand for service and hence on costs of supply — due, in short, to incomplete and/or unreliable information about demand functions and cost functions. Finally, and this is the ponderable theoretical difficulty, it is due to the necessity, faced alike by public utility managements and by regulating agencies, of taking into account numerous conflicting standards of fairness and functional efficiency in the choice of a rate structure.

In view of the complexity of subject matter, the present study will not undertake descriptions of the typical rate structures of the different types of public utilities. The reader unfamiliar with these structures is therefore referred to studies like those of Garfield and Lovejoy (1964), *Gas Rate Fundamentals* (1978), and Phillips (1984, Chapters 10 and 11). A reader unfamiliar with the structure of public utility rates as presented at a more elementary level may find our discussion of general principles hopelessly abstract. Even in its treatment of principles, these chapters should be regarded only as essays on the nature of the more controversial, largely unresolved, problems rather than exhaustive surveys of the voluminous literature on this subject. But they all have one theme in common: that the most formidable obstacles to further progress in the theory of public utility rates are those raised by conflicting goals of ratemaking policy. In this part we address two essential questions: (1) what specific rates will yield a fair return; and (2) what rates and rate relationships should be chosen when a company's earning power is so high that any one of a variety of tariffs could be made to yield adequate over-all revenues? The answers to these questions require the adoption of a set of objectives and the development of criteria by which to judge a sound rate structure.

This is one of the primary purposes of Chapter 16. While recent events in some areas of economics, including the field of indirect regulation (i.e., antitrust), may lead one to believe that economists have a monolithic dedication to one standard — viz., economic efficiency — this is decidedly not the orientation of this study. While economists have been characterized as having a "passionate irrationality for dispassionate rationality", this does not preclude our recognition of appropriate quasi-economic and noneconomic factors in actual ratemaking.

However, for the most part, we do assume an unqualified priority to the fair-return standard of reasonable rate levels, despite the fact — noted in Chapter 10 — that no such priority is necessarily accorded by legal doctrine or ratemaking practice. That is to say, we assume that the rates of any given utility enterprise, taken as a whole, must be designed, in so far as possible, to cover costs as a whole, including a fair return on capital investment. Moreover, we assume the availability of a wide range of alternative rate structures, any one of which could be made to yield the allowed fair return on whatever capital investment is required in order to supply the services that are demanded. This assumption, which implies that the utility enterprise in question enjoys a substantial degree of market power, permits us to center attention on a choice among rate structures, any one of which would be equally fair to investors and equally effective in maintaining corporate credit. Except for incidental references, we shall rule out all of those social principles of ratemaking, discussed in Chapter 8, which may justify the sale of some utility services at less than even marginal costs.

Without doubt, the most widely accepted measure of reasonable public utility rates and rate relationships is cost of service. Thus, we adopt the objectives that were first specified in Chapter 5 as the basis for developing a sound rate structure. However, deviations from a cost-of-service standard may be necessary under a variety of conditions that are often found in practice. In Chapter 16 we list ten attributes of a sound rate structure. Some of these are related directly to the objectives, whereas others may be regarded as deviations from a strict cost standard. Three of the attributes relate to the provision of adequate and stable revenues and rates; five others are based on cost considerations, and the remaining two deal with practicality and acceptability. However, these attributes are unqualified to serve as a basis for sound ratemaking policy because of their conflicting nature and the fact that there are no priorities among them.

In Chapter 17 we introduce the vitally important subject of marginal cost. This term, or one of its approximate synonyms such as incremental cost, is itself a highly ambiguous term, with the result that proposals to base rates on marginal costs mean different things to different people. The most important ambiguity is that suggested by the distinction between short-run and long-run marginal costs. This distinction is of some importance, for most of the differences between incremental and average costs of public utility services are those which apply only when incremental costs are taken to be of a short-run variety. Nonetheless we contend that the difference between cost and noncost standards and between marginal cost and nonmarginal cost standards are more significant than the differences between long-run and short-run marginal costs.

One of the first tasks in Chapter 17 is therefore to discuss the distinctions between these two types of marginal cost. Most of these distinctions would apply, with modifications, to short-run versus long-run incremental costs in general and not alone to costs of increments so small that they are called "marginal." Some economists have gone so far as to propose the acceptance of marginal-cost-based rates even when, in consequence, the resulting revenues will fail to cover total costs and must therefore be supplemented by a tax-financed subsidy. The merits of this unorthodox proposal are discussed briefly in Chapter 18.

However, even under the traditional principle that "rates as a whole should cover costs as a whole," marginal cost should play an important role in the design of rates and rate relationships. In fact, it may play a dual role: first, in setting a lower limit below which no rates will be fixed, not even in order to promote the use of service which could not otherwise find a buyer; and secondly, in serving as a basis for relative rates, subject to deviations of a value-of-service or Ramsey pricing nature. These two uses of marginal cost estimates are developed in Chapters 17, 18 and elaborated in Chapter 20.

The more traditional alternative to modified marginal cost pricing is that of a fully distributed cost methodology. Under this method rate structures are derived in a two-step process known as cost allocation and rate design. The former involves an assignment of revenue responsibility — the revenue allocation — under the assumption that rates should be based solely on costs. The second step is an apportionment intended to determine the pattern of each rate class.

What significance should be attached to these fully distributed costs as guides for rate determination? Public utility managements and public service commissions have often denied or doubted the value of comprehensive total-cost apportionments even as useful guides to rate design. This adverse or skeptical attitude may well be justified, but one should not condemn the procedure too hastily, for it is not devoid of at least a *plausible* rationale. What, then, is this rationale? This is the primary question discussed in Chapter 19.

Chapter 20 deals with the emotionally-charged issue of discrimination. Certain types of discrimination are expressly outlawed without qualification by statute, regardless of the prevailing *Weltanschauung*. But the law does not forbid all forms of discrimination, and commissions may tolerate forms or degrees of discriminatory ratemaking that they might otherwise forbid in order for a company to maintain sound corporate credit. However, there is a good deal of confusion about exactly what constitutes discrimination as defined by economists and noneconomists. So one of the tasks is to define what constitutes discrimination, due or undue. A central point we emphasize is that discrimination is a cost-related concept. It is cost related in the sense that differences in rates are discriminatory only to the extent that they deviate from marginal costs. Moreover, arguments can be made in support of discriminatory rates based on "Ramsey" rules because, under certain conditions to be specified in Chapter 20, they can be used to enhance welfare. We also explore briefly the relatively new and untested area of axiomatic cost pricing in this chapter.

CHAPTER 16

CRITERIA OF A SOUND RATE STRUCTURE

The design of electric rates has recently emerged from the closet of regulatory neglect to a new prominence. (Cudahy and Malko, 1976, p. 47.)

INTRODUCTION

Public utility counsel have sometimes argued that once a company's total revenue requirements have been determined by a commission, the choice of a pattern of rates that will yield the allowed revenues should be left to the discretion of management, which will then be in an impartial position to make a fair apportionment of burdens among its different classes of ratepayers. This is only a half-truth because, among other reasons, a utility company is concerned not just to secure rates that will presently yield the approved fair rate of return, but to develop a pattern of rates that will promote growth of earnings and that will protect these earnings against adverse business conditions. The better the utility management, the greater are these concerns.

Historically, state public service commissions have given more attention to rate relationships than to rate levels. Their primary concern with specific rates was to provide favorable treatment to residential customers. However, the energy price increases of the 1970s and the increasingly competitive environment in all the utility industries during the 1980s has resulted in even more active intervention by organized residential consumer groups and very large industrial customers, with greater concern with specific rates on the part of the regulatory commissions. A plausible reason for the reluctance on the part of a commission to override the rate-pattern policies of a utility company is the one suggested many years ago by Watkins (1921, p. 37), in expressing regret that few American commissions had contributed substantially to the development of principles of electric-rate design. "This situation," he wrote, "is perhaps partly due to doubt as to the possession of adequate powers, but more fundamentally to the diffidence of commissioners when confronted with a subject so complex, both theoretically and practically, as that of electric rates." The commissions that have given the most attention to rate-structure principles are the stronger commissions, such as those of California, New York, Wisconsin and others, which have the aid of relatively large expert staffs.

Essential Questions in Rate Design

Even if the determination of revenue requirements under a fair-return standard were taken as the master rule of ratemaking, there would still remain two essential questions:

(1) what specific rates will yield a fair return, and

(2) what rates and rate relationships should be chosen when a company's earning power is so high that any one of a variety of tariffs could be made to yield adequate overall revenues?

We turn now to principles of ratemaking designed to throw light on these two questions, but particularly on the latter. By what basic standards, for example, shall regulation pass judgment on a system of electric-utility rates which allows liberal discounts for incremental blocks of energy; or which levies higher charges, per kilowatt-hour, on residential than industrial ratepayers; or which concedes lower rates for off-peak consumption than for consumption at peak-time hours or seasons? And what are the merits of the contentions that natural gas should be priced higher for customers who receive gas on a firm, as opposed to an interruptible, basis? With the telephone utilities, does public policy justify the practice of the industry in setting higher rates for service offered in larger urban communities than for comparable service in small, often rural, communities even when these differentials are not based on differences in cost of service? These are mere random samples of the many practical issues falling under the subject of rate structure. Let us examine one of these in more detail.

Historically, rates for local telephone service have been based on a value of service standard. In particular, the rates for service in rural areas are generally less than the rates in the urban areas. The reason for this was that it was believed the service in the urban areas was more valuable since the subscribers had a larger number of people in their local calling area. This application of value-of-service pricing totally disregards the fact it is more costly to provide telephone service in the rural areas than in urban areas. In Nebraska, for example, in 1988 the local rate for Northwestern Bell in Omaha was $15.68 per month (including local usage and taxes) and the cost for just the local loop was $14.30. Home Telephone, a small company serving a rural Nebraska community, charged $4.50 per month (including local usage and taxes), but the monthly cost for just the loop was $23. In order to make each company solvent, long distance rates were averaged which allowed rural companies to offer service below cost. The result of this was that companies in the rural areas were subsidized by ratepayers in the urban areas through long distance rates.

However, when the move to competition in the industry began, policymakers recognized the incompatibility of competition and cross subsidization. In Docket 78-72, the Federal Communications Commission (FCC) began the move towards cost-based pricing and to phase out cross subsidies. However, since rural companies were faced with large rate increases the FCC established a plan designed to protect these companies. Under this plan, the FCC established the Universal Service Fund, allowing high cost companies to assign part of their costs to toll service and thereby partially continue the subsidy from urban areas.

Complexity of the Issues

In this chapter we mostly emphasize a normative theory about what should be done as opposed to positive theory about how the world is. One of the paramount normative issues is rate structure. Rate-structure problems are far more complex than problems of a fair return, even though the latter are by no means elementary; and they are even less amenable to solution by reference to definite principles or rules of ratemaking. In part, the complexity is due to the mass of technical detail, including the technology of metering, involved in the design and administration of workable rate schedules for different types of utility enterprises. In part it is due to the inability of the ratemaker to predict the effects of rate changes on demand and hence on costs of supply — due, in short, to ignorance of demand functions and cost functions. But in part — and this is the theoretical difficulty — it is due to the necessity, faced alike by public utility managements and by regulating agencies, of taking into account numerous conflicting standards of fairness and functional efficiency in the choice of a rate structure. The nature of some of these conflicts will be revealed as this discussion proceeds. But, by way of illustration, we may note the conflict between the desirable attribute of simplicity and the otherwise desirable attribute of close conformity to the principle of service at cost. Here, as with other clashes among various desiderata of ratemaking policy, the wise choice must be that of wise compromise; and in reaching this compromise, the practical rate expert would look in vain to any general theory of public utility rates for a scientific method of reaching the socially optimum solution. An economically rational approach would involve comparing the benefits with the costs, but this is not always easy or even feasible. For instance, measuring the intangible costs of time-of-use metering cannot be readily assessed. Needless to say, no one has supplied a formula by which to draw the line between too much and too little simplicity.

A recurring theme of this book is that there are conflicts among the competing objectives of ratemaking that are difficult to resolve, thus making the climb to the peak of Mount Pareto slippery. While our preference as economists is to make greater use of the criterion of service at cost as the standard by which alternative rate structures are compared, we realize that to expect this bias of others would be hopelessly naïve. We do believe, however, that the ratemaker should utilize the cost standard as a benchmark, with assessments of the efficiency advantages (or disadvantages) of particular rate structures playing a subsidiary role; social and fairness standards also may be appropriate within the limits of authority that a regulating body may be able to exercise. As the French thinker Blaise Pascal noted: "We know the truth not only by reason, but also by the heart."

CRITERIA OF A DESIRABLE RATE STRUCTURE

Throughout this study we have stressed the point that, while the ultimate purpose of rate theory is that of suggesting criteria of reasonable rates and rate relationships, an intelligent choice of these depends primarily on the accepted *objectives* of ratemaking policy and secondarily on the need to minimize undesirable side effects of rates otherwise best designed to attain these objectives. However, no rational discussion of the relative merits of cost of service and value of service, for example, as standards of desirable rates or rate relationships is possible without reference to the question of what desirable results the ratemaker hopes to secure, and what undesirable results are to be minimized, by a choice between or mixture of the two standards. This was recognized explicitly in the Electric Utility Rate Design Study sponsored by the National Association of Regulatory Utility Commissioners (NARUC) and undertaken by the Electric Power Research Institute (EPRI) (See Malko, Smith and Uhler, 1981, p. 1-6). Not only this: the very *meaning* to be attached to ambiguous, proposed standards such as those of "cost" and "value" — an ambiguity not completely removed by the addition of familiar adjuncts, such as out-of-pocket costs, or marginal costs, or average costs — must be determined in the light of the purposes to be served by the public utility rates as instruments of economic policy. This is a commonplace; but it is a commonplace which, so far from being taken for granted, needs repeated emphasis.

In this section we first outline a set of attributes to be sought in the development of a sound rate structure. While we know that regulation will not guarantee good economic performance, we should at least like it to arrest or curb egregiously bad performance. For instance, regulation should allow a fair rate of return, but not guarantee or protect a regulatee against mismanagement or adverse business conditions. Sound rate relationships are essential to the attainment of these desirable ends, but criteria are required to judge whether, and to what extent, these objectives have been attained. In our attempt to put the competing criteria into an explicit form we recognize that we are violating the sage advice of Charlie Brown that: "No problem is so big that it can't be run away from."

Attributes of a Sound Rate Structure

What are the attributes to be sought in the development of a sound rate structure? Many different answers have been suggested in the technical economics literature and in the reported opinions by courts and commissions. A number of writers have summarized their answers in the form of a list of desirable attributes of a rate structure, comparable to the canons of taxation found in Adam Smith's *Wealth of Nations* (1937 — originally 1776) and subsequent treatises on public finance. In very general terms (see e.g., Federal Energy Regulatory Commission, Order No. 436, October 9, 1985) optimal rates: should provide clear, efficient, effective, informative, and cost-effective market signals about the present and the future cost of service to buyers and sellers, (which requires that prices track costs); should embody strong incentives for optimal present and future cost and service quality configuations; should give buyers and sellers optimal flexibility in selecting sellers and buyers respectively; should allow utilities to serve as agents of progress; should maintain or improve distributive equity, and should allow for the attainment and maintenance of a flexible (non *ad hoc*) regulatory framework with a modicum of necessary delay and obfuscation (and even a willingness of a commission to dissolve itself under the appropriate competitive or contestable conditions!). But this is a pretty general menu, and more specific direction is needed when applying them to an empirical world. As someone once said, "the real world is only a special case of the theoretical world, and not a very interesting one at that." But many practical-minded people would disagree, so let us push on to greater specificity.

The list that follows is fairly typical, although we have derived it from a variety of sources, instead of relying on any one presentation. Of the ten proposed attributes enumerated in this section, the first three relate to the provision of adequate stable and predictable revenues and rates; the next five are based on cost, efficiency, and equity considerations, and the remaining two deal with matters of practicality and acceptability. However, the sequence in which the ten attributes are presented is not meant to suggest any order of importance. Moreover, there is, perforce, some inconsistency and redundancy in any such listing. We are simply trying to identify the desirable characteristics of utility performance that regulators should seek to compel through edict.

Revenue-related Attributes:

1. Effectiveness in yielding total revenue requirements under the fair-return standard without any socially undesirable expansion of the rate base or socially undesirable level of product quality and safety.

2. Revenue stability and predictability, with a minimum of unexpected changes seriously adverse to utility companies.

3. Stability and predictability of the rates themselves, with a minimum of unexpected changes seriously adverse to ratepayers and with a sense of historical continuity. (Compare "The best tax is an old tax.")

Cost-related Attributes:

4. Static efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:

   (a) in the control of the total amounts of service supplied by the company;

   (b) in the control of the relative uses of alternative types of service by ratepayers (on-peak versus off-peak service or higher quality versus lower quality service).

5. Reflection of all of the present and future private and social costs and benefits occasioned by a service's provision (i.e., all internalities and externalities).

6. Fairness of the specific rates in the apportionment of total costs of service among the different ratepayers so as to avoid arbitrariness and capriciousness and to attain equity in three

dimensions: (1) *horizontal* (i.e., equals treated equally); (2) *vertical* (i.e., unequals treated unequally); and (3) *anonymous* (i.e., no ratepayer's demands can be diverted away uneconomically from an incumbent by a potential entrant).

7. Avoidance of undue discrimination in rate relationships so as to be, if possible, compensatory (i.e., subsidy free with no intercustomer burdens).

8. Dynamic efficiency in promoting innovation and responding economically to changing demand and supply patterns.

Practical-related Attributes:

9. The related, practical attributes of simplicity, certainty, convenience of payment, economy in collection, understandability, public acceptability, and feasibility of application.

10. Freedom from controversies as to proper interpretation.

Lists of this nature are useful in reminding the ratemaker of considerations that might otherwise be neglected, and also useful in suggesting important reasons why problems of practical rate design do not yield readily to scientific principles of optimum pricing. But they are unqualified to serve as a base on which to build these principles because of their ambiguities (how, for example, does one define "undue discrimination"?), their overlapping character, their inconsistencies, and their failure to offer any basis for establishing priorities in the event of a conflict. For such a basis, we must start with a simpler and more fundamental classification of ratemaking functions and objectives.

Some of these attributes in the aforementioned list are based directly on the primary functions of public utility rates first presented in Chapter 4, and the related objectives to be sought in the establishment of a cost-based standard of ratemaking (Chapter 5). These objectives provided the basis for development of the criteria of a fair return (Chapter 10). These same objectives, derived from the four primary functions, can now be used to specify the criteria of a sound rate structure discussed in the following section.

The Primary Criteria Are Based on the Objectives of Regulation

General principles of public utility rates and rate differentials are necessarily based on simplified assumptions both as to the objectives of ratemaking policy and as to the factual circumstances under which these objectives are sought to be attained. Attempts to make these stated principles subserve all special objectives and cover all specific conditions would be hopeless. Writers on the theory of rates are therefore at liberty to base their analyses on the acceptance of those objectives which are of wide application and the attainment of which may be aided by whatever tests or measures of sound rate structure the analyses suggest.

Among these objectives, the following three may be called primary, not only because of their widespread acceptance, but also because most of the more detailed objectives discussed in the literature are ancillary thereto: (1) the revenue-requirement, production-motivation, or financial-need objective; (2) the optimum-use, demand control, or consumer-rationing objective; and (3) the compensatory income transfer function or fair-cost-apportionment objective. Based on these objectives we propose the following three primary criteria by which to judge the soundness and desirability of a rate structure for public utility enterprises. As outlined below, these objectives are related closely to five of the ten attributes specified above.

Criterion 1 - Capital Attraction

(Attribute 1): based on the revenue-requirement objective, with due regard to potential problems of socially undesirable levels of rate base, product quality, and safety; it takes the form of a fair-return standard with respect to private utility companies;

Criterion 2 - Consumer Rationing

(Attributes 4 and 5): based on the consumer-rationing objective, under which the rates are designed to discourage the wasteful use of public utility services while promoting all use that is economically justified in view of the relationships between the private and social costs incurred and benefits received;

Criterion 3 - Fairness to Ratepayers

(Attributes 6 and 7): fair-cost-apportionment objective, which invokes the principle that the burden of meeting total revenue requirements must be distributed *fairly* and without arbitrariness, capriciousness, and inequities among the beneficiaries of the service and so as, if possible, to avoid undue discrimination.

The objectives specified above correspond to three of the four primary functions of utility rates set forth in Chapter 4. The efficiency-incentive function, or that of encouraging managerial efficiency, is omitted because of its more direct bearing on the desirable criteria for a fair rate of return. Some writers, especially the older ones, e.g., Wallace (1941, pp. 475-478) would add a fifth objective: that of benefitting specific classes of ratepayers, such as customers of sub-standard income or a depressed industry. This objective comes under the heading of social principles of ratemaking as we have used the term in Chapter 8.

In actual rate cases, these three objectives of reasonable rates and rate relationships, and particularly the last two, are by no means always sharply distinguished. But the distinction may be illustrated by the imagined example of a request, submitted to a regulating commission by a group of ratepayers, that an electric (gas or tele-communications) company be ordered forthwith to abandon its present, somewhat elaborate, schedule of class rates, block rates, and two-part or three-part tariffs in favor of a uniform kilowatt-hour (therm or message minute) rate for all customers throughout its franchise territory. Almost certainly this proposal would be held subject to the threefold objection:

(a) that no uniform rate, however high, could be made to yield a fair return on the company's invested capital;

(b) that, even if it could do so, rate uniformity despite lack of cost uniformity in the supply of different types of service would impose *unfair* and discriminatory burdens on the consumers of the less costly services; and

(c) that, quite aside form its unfairness, the uniform rate would result in a serious underutilization of plant capacity because it would cut down the demand for services (especially, for off-peak services) that could be supplied at incremental costs materially below average unit costs, while stimulating a wasteful on-peak demand for services that can be supplied only at incremental costs higher than average costs and it does not reflect any differential social costs and benefits in different areas.

Some writers who confine their attention to what they call the "economic" principles of public utility rates have ignored the third criterion of a sound rate structure in their development of their principles of public utility rates on the ground that fairness questions are beyond the competence of professional economists (on the general issue of fairness, see Zajac, 1985, and Baumol, 1986). Instead, they have centered attention on the second criterion, often with special reference to its application under the constraint of a revenue-requirement constraint. But a refusal to recognize fairness issues as relevant to the design of a sound rate structure would so far remove the analysis from the objectives of Chapter 5 and divorce theory from practice that these issues will not be completely ignored in the discussion that follows.

Stability and Predictability of Rates: A Secondary Criterion

Attributes 2 and 3 on stability and predictability have been neglected relative to those associated with the three primary criteria, and deserves further consideration. In ratemaking, the attribute of *predictability*, is more important than *stability* per se. Time-of-use rates, for example, are not stable (in a strict sense), but are predictable and, most would agree, desirable. One could certainly argue that ratepayers should be given the information they need to *predict* rates accurately. However, this does not imply a necessary need to keep rates stable at the expense of otherwise efficient pricing. For instance, in the case of rate base valuation, most jurisdictions opted for the rate stability associated with original costs (also for the popular understanding and administrative practicality) even though this method has an economic cost in terms of ideal resource allocation and use during periods of changing price levels. In that case, the presumably intelligent choice between the merits and demerits of the alternatives led decisionmakers to conclude that the price society pays for this stability is reasonable.

Stability, like freedom, is not free. Utility regulation can and does affect the social cost of risk bearing (Schmalensee, 1979, p. 36-37). The bearers of risks have real costs imposed on them. Economic efficiency calls for the one's best able to bear risk to do so. Ideally, the regulatory process only redistributes and does not increase total risks. Erratic regulation can increase a firm's real costs, including capital costs. Stabilized rates (returns) shift risks from ratepayers (shareholders) to shareholders (ratepayers). Utilities need revenue stability to mitigate the sunk costs of their highly specialized systems that make them prime candidates for expropriation or opportunism. However, as Yandle (1987) puts it: "You can fleece a sheep many times, but you can only skin him once."

A monolithic critic might ask: why place such great importance on revenue and rate stability and predictability when no such constraints operate in the unregulated sector (especially in light of the business cycle)? The answer to this question is provided in great detail in the next two chapters. For the moment, let it suffice to note five major considerations. First, some users have a strong preference for rate stability in planning even if it means some sacrifice in the (higher) level of initial rates. This is especially true of customers who use the utility in the production of other goods and services and who fear that rivals may obtain advantages by acquiring the service more cheaply and reliably elsewhere (Baldwin, 1987, p. 225). Second, there are transaction costs involved in the determination, administration, and publicity of a rate structure; these include advertising, publishing and distributing price lists, issuing new catalogs, etc. Third, since the greater asset-specificity in regulated markets provides more scope for opportunistic behavior, assurances of predictable revenues are appropriate in a regulated industry. Fourth, rate stability and more particularly predictability, are needed to allow the users to secure a rational control of demand. We want to make sure that regulation does not increase, but only redistributes the total and real risk. Therefore, a fourth criterion, although of a somewhat lower rank than the three primary ones discussed earlier, is that of stability and predictability of specific rates and of revenues.

Some Simplifying Assumptions

In the remainder of this Part Four, except for the sections in Chapter 17, the principles governing the development of a sound rate structure will be discussed under the assumption that rates are designed primarily to subserve the four primary objectives of rate-making policy specified earlier. But in order to avoid extreme complexities, the following four explicit assumptions are made, all of which are implicit in much of the literature on public utility rates. Some of these are reiterations of the criteria, whereas others are additional assumptions required for clarity.

In the first place, we shall impute an unqualified priority to the fair-return standard of reasonable rate levels despite the fact, noted in Chapter 10, that no such priority is accorded either by legal doctrine or by ratemaking practice. That is to say, we shall assume that the rates of any given utility enterprise, taken as a whole, must be designed as far as possible to cover costs as a whole including (or plus) a fair return on capital investment.

In the second place, we shall assume the availability of a wide range of alternative rate structures, any one of which could be made to yield the allowed fair return on whatever capital investment is required in order to supply the services demanded. This assumption, which implies that the utility enterprise in question enjoys a substantial degree of monopoly power, permits us to center attention on a choice among rate structures, any one of which would be equally fair to investors and equally effective in maintaining corporate credit.

In the third place, throughout this handbook, we operate under a general presumption that pricing at marginal cost would lead to a revenue shortfall; i.e., the firm operates in the range of declining unit costs. However, there is evidence now to suggest that there are certain aspects of utility operations, such as the generation of electricity, which are in the range of increasing unit costs. Thus, the possibility exists that a company could find itself overall in the increasing cost range. This nontrivial possibility should be kept in mind in discussions of the problem of revenue reconciliation.

And in the fourth place, except for incidental references, we shall rule out all of those social principles of ratemaking, discussed in Chapter 8, which may justify the sale of some utility services at less than even marginal costs. While the rate structure may be used as a tool for redistributing income, economists in general prefer alternative fiscal policies, such as taxation and direct subsidies. This is so primarily because of the limited span over which any single regulatory body may exercise control. Thus, the positive realities impinge on our normative analyses.

IMPORTANCE AND LIMITATIONS OF THE PRINCIPLE OF COST OF SERVICE

Cost-of-service as a Basic Standard

Without doubt the most widely accepted measure of reasonable public utility rates and rate relationships is cost of service. For example, based on their extensive researce associated with the Electric Power Research Institute (EPRI) rate design study, Malko, Smith and Uhler (1981, Chapter 4) conclude that "In general, cost-based rates satisfy the commonly held multidimensional, sometimes conflicting, pricing objectives better than noncost-based rates". In the literature, the cost-of-service measure is generally given a dominant position even by writers who insist upon, or reluctantly concede, the necessity for deviations from cost in the direction of value-of-service principles or of various social objectives of ratemaking. However, Stanley (1984) argues that because of the interdependency among ratepayers of basic service and the deterrence effects of the connection charges — e.g., access to the telephone network — the optimal price would be set *below* marginal cost with subsidization by nonbasic services such as the Yellow Pages, Touch-Tone service, long-distance service, etc. Be that as it may, in actual practice there is usually an obvious, marked to meet separate tests of financial self-sufficiency, project by project. (See especially Vickrey, 1955, who has been one of the leading American authorities on marginal-cost pricing in its application to public utilities.) Where optional routes are available for trucks and automobiles, the resulting mixture of high-toll, low-toll, and no-toll routes is almost sure to lead to serious economic wastes, because it motivates the road users to base their choices on relative money costs that do not reflect relative social costs. This same problem is evident in the determination of electric and natural gas rates in separate proceedings before a regulating commission.

But the toll-bridge illustration is merely a simple example of the asserted advantages of marginal-cost pricing over full-cost pricing applicable to all public utilities — applicable, in short, to a vitally important group of noncompetitive industries with respect to which the gap between the two types of pricing is especially wide. To be sure, marginal costs even of a short-run variety are less likely to be merely trivial for these other utilities than for toll bridges. Moreover, opportunities for rate discrimination, such as with Ramsey pricing, as a means of full-cost recovery are likely to be much better. But the general principle still applies.

And, as to the use of discrimination as a device by which to jump the gap between average-cost and marginal-cost standards, Hotelling cites some unhappy consequences of the attempts by railroads to make these jumps as failing to justify any complacency toward this device for the attainment of essentially inconsistent advantages.

Critique of Proposal to Fix Rates at Short-run Marginal Costs

Reserving for a later section a discussion of the much milder proposal to base rates on marginal costs of a long-run character, let us now consider critically the merits of the far more drastic proposal to base rates on short-run marginal costs. Already some of the more serious objections have been noted in Chapter 17, which discusses the relative merits of the two major types of marginal costs as measures of *minimum* rates. Harbeson (1955) presents a well-balanced critical appraisal of marginal-cost pricing, both of the short-run and the long-run varieties. Harbeson comments on one criticism not yet discussed in this chapter: that the supporters of marginal-cost pricing for regulated monopolies ignore the supposed failure of unregulated prices to come into accord with the marginal costs under the most widely prevailing types of competition, namely, imperfect competition. On the other hand, Andersson and Bohman (1985) note many shortcomings on the concept of long-run marginal costs.

Measurement and Related Problems. First, let us recall that, with most public utilities, the really significant choice is not a simple choice between *marginal* cost and *average* cost as the basis of ratemaking. To be sure, the assumption that the ratemaker faces this dire dilemma is not too far from reality in the toll-bridge example, since here the practical opportunities for rate differentiation are severely limited. Hence the bridge example presents an unusually forcible case for the adoption of marginal-cost pricing or, at least, for the abandonment of any attempt to make each particular bridge rest on its own financial foundations. But with most other utilities there exists a wide variety of plausible rate structures, including those which resort to multi-part ratemaking, block ratemaking, and various forms of discriminatory pricing. Most of the rate structures now in effect are subject to material improvement with advances in the technique of rate design but without abandoning the total-cost principle. While none of them can be expected to have *all* of the consumer-rationing advantages of unqualified marginal-cost pricing, neither can they be assumed to result in economic losses of the order of magnitude of those suggested by an attempt to make a particular toll bridge financially self-sufficient through a uniform charge of so many cents or dollars per vehicle per crossing. Unfortunately, however, the measures of the relative gains and losses of marginal-cost pricing versus any given type of discriminatory, full-cost pricing that are suggested by economic theory are impossible to apply in terms of present factual knowledge. Also remember that the relevant marginal costs must also include the measurement or metering cost which, for example, accounts for for 10-25 percent of the cost of the average measured telephone call, depending on the type of serving equipment (Berryhill and Reinking, 1984).

Importance of Stability of Rates. Secondly, we must consider whether or not the almost undeniably superior efficiency of short-run marginal-cost pricing as a means of securing the optimum utilization of a plant of temporarily redundant capacity warrants the surrender or impairment of all of the other important functions of utility rates, even the function of aiding in the control of the demand for and supply of utility services in the longer run. Even this claim of superiority must be conceded only on the assumption that the better-than-nothing use of temporarily excess capacity will not materially interfere with possible emergency use. Instant readiness to serve may well be the best use of idle capacity. Clemens (1956, pp.92-93) had this point in mind in doubting the wisdom of proposed attempts by electric utilities to encourage three-shift factory loads by the concession of very low rates for off-peak industrial service (1956, pp. 92-93). To the same effect, see Hutt (1939), and Troxel (1950). Resort to three shifts, Clemens recalled, was one of the major ways by which the country avoided a menacing power shortage during the Second World War. "One day's loss of lives," he added, ". . . constitutes quite a lot of marginal disutility."

By and large, the major influence exercised on consumer demand for utility services by any current rates of charge for these services is an influence based on the expectation that these rates indicate, at least in a general way, the rates that will remain in effect over a considerable period of time. For it is the anticipated, fairly long-run costs of service which potential ratepayers wisely take into account when they face a decision whether to commute from Nowhereville to Somewhereville despite the daily payment of tolls on the Goingsomewhere Bridge; or whether to equip their homes with an electric range or with electric air conditioning; or whether to locate their aluminum plants on the Elysium River rather than in the state of Nirvana. Once having become dependent on the services required for the operation of expensive complementary equipment, the consumer's responsiveness to temporary changes in rates of charge will probably be very limited. In short, the own price elasticity of demand for utility services can be expected to be much greater in the fairly long run than in any very short period of time. But if utility rates were to be made as volatile as may be required by the mandate of conformity to short-run marginal costs, they would deprive consumers of those expectations of reasonable continuity of rates and of rate relationships on which they must rely in order to make rational advance preparations for the use of service. But even apart from the frequent rate fluctuations that would be necessary if there were frequent changes in short-run marginal costs that make it difficult to respond intelligently and quickly, there is another limiting factor. "On a mere mechanical level, there is always the cost involved in the determination, publication and administration of a rate structure." (Vickrey, 1955, p. 605). It is mindboggling to think of all the combinations and permutations of marginal-cost pricing that would be forthcoming if all the possibilities involved were considered, i.e., various generating stations, customer load centers, several voltage levels, and, perhaps most important of all, the fact that there are 8,760 hours in a year (Cicchetti 1975). But, once again the rational thing to do is to consider the estimated incremental gains from the stability and predictability of rates against the probable incremental costs of achieving other desirable criteria of a sound rate structure.

TAB 3

Rating Report

The Manitoba Hydro-Electric Board

Ratings

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DBRS
Insight beyond the rating.

Debt	Rating	Trend
Long-Term Obligations	A (high)	Stable
Short-Term Obligations	R-1 (middle)	Stable

Note: These Obligations are based on the status of the Manitoba Hydro-Electric Board as a Crown agent of the Province of Manitoba and the unconditional guarantee provided by the Province on Manitoba Hydro's third-party debt, and thus reflect the Province's debt ratings.

Rating Update

DBRS Limited (DBRS) has updated its report on the Manitoba Hydro-Electric Board (Manitoba Hydro or the Utility). The ratings assigned to the Utility's Long-Term Obligations and Short-Term Obligations are a flow-through of the ratings of the Province of Manitoba (the Province; rated A (high) and R-1 (middle) with Stable trends by DBRS). Pursuant to *The Manitoba Hydro Act*, the Province unconditionally guarantees almost all of Manitoba Hydro's outstanding third-party debt (please see the *DBRS Criteria: Guarantees and Other Forms of Support* methodology for further details). The Province also provides most of the Utility's financing through provincial advances (approximately 99% of total debt as at March 31, 2016). DBRS considers Manitoba Hydro to be self-supporting, as it is able to fund its own operations and service debt obligations.

In early 2016, Manitoba Hydro engaged the Boston Consulting Group to conduct a review of its financial, operating and capital plans, with particular focus on the Bipole III Transmission Reliability Project (Bipole III), the Keeyask Infrastructure and Generating Station Project (the Keeyask Project) and the Manitoba-Minnesota Transmission Project (MMTP). The results, issued in September 2016 (the BCG Report), concluded that although the decision to proceed with the Keeyask Project was imprudent as some major risks were not fully considered, the best path forward was to continue construction on all three projects. The BCG Report noted, however, that total cost overruns of $1 billion could occur along with possible delays to the in-service dates of 12 months for Bipole III and 21 months for the Keeyask Project. The BCG Report also noted the rising leverage at the Utility as a result of the substantial capex; debt-to-capital at Manitoba Hydro had risen to 83% at F2016 and had been expected to peak at 88%, significantly above the target capital structure of 75% debt. A new board appointed at Manitoba Hydro in 2016 intends to limit the deterioration in the Utility's balance sheet. As a result, the Utility has begun reviewing initiatives to help alleviate pressure on its key financial ratios, such as improving operational efficiencies, requesting annual rate increases higher than the previously planned 3.95%, as well as a potential equity injection from the Province. DBRS sees these initiatives, if actualized, as positive to Manitoba Hydro's financial profile, as they will provide some financial flexibility for the Utility, especially in the event of adverse drought conditions or further cost overruns on the projects.

Continued on P. 2

Financial Information

The Manitoba Hydro-Electric Board	For the year ended March 31 [1]				
(CAD millions where applicable)	2016	2015	2014	2013	2012
Total debt in capital structure [2]	83.0%	81.3%	79.4%	78.5%	77.9%
Cash flow/Total debt	5.4%	5.3%	6.4%	6.1%	6.3%
EBIT gross interest coverage (times)	0.91	1.07	0.96	0.89	0.80
Net income before non-recurring items	55	145	178	92	61
Cash flow from operations	791	665	691	589	567

1 2015 to 2016 based on IFRS; 2012 to 2014 based on Canadian GAAP. 2 Adjusted for other comprehensive income.

Issuer Description

The Manitoba Hydro-Electric Board, a wholly owned Crown corporation of the Province of Manitoba, is a vertically integrated electric utility that provides generation, transmission and distribution of electricity to approximately 567,634 customers throughout Manitoba, and natural gas service to approximately 276,858 customers via its subsidiary, Centra Gas Manitoba Inc. The Utility also exports electricity to more than 25 electric utilities through its participation in four wholesale markets in Canada and in the Midwestern United States.

Rating Update (CONTINUED)

DBRS continues to view Manitoba Hydro as self-supporting, as its earnings and cash flows continue to be sufficient to cover its operating expenses and to service its outstanding debt. However, DBRS could consider reclassifying a portion of the Utility's debt to be tax-supported should the financial health of the Utility deteriorate to the point where its expenses cannot be recovered through rates. If this were to occur, it could potentially put downward pressure on the Province's credit rating. Similarly, a large equity injection by the Province that materially increases tax-supported debt could also put downward pressure on the Province's credit profile. At this time, however, DBRS expects the Province's ratings to remain stable.

Rating Considerations

Strengths

1. Debt is a direct obligation of the Province
Manitoba Hydro is an agent of the Crown, and its debt securities, except for $65 million of Manitoba Hydro-Electric Board Bonds (less than 1% of total debt at March 31, 2016), are held or guaranteed by the Province; therefore, the ratings assigned to Manitoba Hydro's obligations are a flow-through of the ratings assigned to the Province.

2. Low-cost hydro-based generation
Low-cost hydroelectric-based generating capacity results in one of the lowest variable cost structures in North America, which has enabled Manitoba Hydro to provide electricity to its domestic customers at one of the lowest rates on the continent. This gives the Utility the flexibility to increase rates in the future, especially in light of the substantially heightened capex requirements.

3. Access to export markets
Manitoba Hydro's interconnections (approximately 43% of installed capacity), with firm export transfer capability of 2,100 megawatts (MW) to the United States, 175 MW to Saskatchewan and 200 MW to Ontario, along with additional non-firm transfer capability, provide the Utility with access to favourable export markets. The interconnections also provide a secure supply of electricity for domestic customers during times of poor hydrology.

Challenges

1. High leverage
Leverage at Manitoba Hydro has been increasing over the past years as a result of the significant capital projects currently being undertaken. As such, the debt-to-capital ratio reached 83% at F2016, above the target capital structure of 75% debt. The Utility had forecast leverage to peak at 88% when the Keeyask Project is brought in service, but with the possibility of cost overruns and delays detailed in the BCG Report for Bipole III and the Keeyask Project, leverage could potentially further increase if mitigants are not enacted. The Utility is currently reviewing potential initiatives, such as requesting higher rate increases or an equity injection from the Province, which could help alleviate pressure on its key financial ratios.

2. High level of planned capex
The Utility is currently undergoing a period of substantial capex, with major projects that include Bipole III (total capex of approximately $4.65 billion) and the Keeyask Project (total capex of approximately $6.5 billion). As a result, capex for the Utility had been forecast to average approximately $2.4 billion per year before falling to $900 million beginning in F2022. However, the BCG Report notes that total capex for Bipole III could increase to $5 billion, while the Keeyask Project could reach $7.8 billion. As such, average capex for the medium term may continue to climb and further pressure the already high debt levels.

3. Hydrology risk
Given that approximately 92% of Manitoba Hydro's installed generating capacity is hydroelectricity-based, earnings and cash flows are highly sensitive to hydrological conditions. The Utility is also exposed to significant price and volume risk because of its export commitments under the fixed price-to-volume contract, which may require the Utility to procure power supply from import markets if hydrological conditions are unfavourable.

Major Projects (Under Construction and Planned)

Project	Estimated Cost ($ millions)	Planned Construction Start Date	In-Service Target Date
Bipole III Transmission Reliability Project	4,650	2013	2019
Keeyask Infrastructure and Generating Station Projects	6,500	2014	2021
Manitoba-Minnesota Transmission Project	450	2017	mid-2020

- **Bipole III**: This project involves the construction of a 500-kilovolt (kV) high-voltage direct current transmission line, along with new converter stations. Construction began during winter 2013/2014, and the transmission line is expected to be in service for 2018. The BCG Report noted that the cost for the project may increase to approximately $5 billion with the in-service date delayed until mid-2019.
- **Keeyask Project**: This project includes the development of a 695 MW generation station on the Nelson River. Construction began in July 2014; the first generator is expected to be in service for 2019 and the remaining units are expected to be in service by 2021. The BCG Report noted that the cost for the project may increase to approximately $7.8 billion with the in-service date delayed until mid-2021.
- **MMTP**: This proposed project involves the construction of a 500 kV alternating current transmission line from Winnipeg to the Manitoba-Minnesota border, where it will interconnect with the Great Northern Transmission Line (GNTL) to be built by Minnesota Power. The Province authorized Manitoba Hydro to proceed with the project in July 2014, and the Utility filed an Environmental Impact Statement in September 2015, which began the formal regulatory review process. Minnesota Power has received all major regulatory approvals for the GNTL including a Presidential Permit, and expects to start construction early in 2017.

Earnings and Outlook

(CAD millions where applicable)	2016	2015	2014	2013	2012
	For the year ended March 31 [1]				
Total electricity revenues	1,791	1,812	1,861	1,733	1,573
Net gas revenues	172	161	163	147	132
Total revenues	**1,963**	**1,973**	**2,024**	**1,880**	**1,705**
EBITDA	983	990	1,068	991	865
EBIT	595	621	626	568	484
Gross interest expense	654	581	654	636	603
Earning before taxes	45	134	156	79	61
Net income before non-recurring items	55	145	178	92	61
Reported net income	49	136	174	92	61
Return on equity [2]	1.9%	5.0%	6.6%	3.5%	2.4%

1 2015 to 2016 based on IFRS; 2012 to 2014 based on Canadian GAAP. 2 Adjusted for other comprehensive income.

F2016 Summary

- Earnings declined in F2016 as milder winter temperature for the period reduced revenues from both the domestic electric and natural gas segments, while depreciation and interest expense rose from the continued high capex.
  - This was slightly offset by a 3.95% rate increase effective August 1, 2015.

F2017 Outlook

- Manitoba Hydro has forecast earnings in F2017 to remain low, with expected net income of approximately $25 million. While rates increased by 3.36% effective August 1, 2016, this will likely be more than offset by rising depreciation and interest costs.
  - The Utility had requested a rate increase of 3.95% effective April 1, 2016. The delay in implementation and lower approved increase will also have a negative impact on earnings.
- DBRS expects the Utility's profitability to remain challenged over the medium term as the Utility continues to invest significant amounts for Bipole III and the Keeyask Project. However, the new board at Manitoba Hydro appointed earlier in 2016 intends to improve leverage at the Utility back to the target debt-to-capital ratio of 75%.
  - While Manitoba Hydro had planned to file for more moderate annual rate increases of 3.95% until F2029, the Utility is currently considering requesting higher rate increases for the next few years to help improve the leverage ratio. DBRS had noted that rate increases of 3.95% were expected to be insufficient for Manitoba Hydro to recover costs related to major projects for the medium term.
  - Other initiatives include the plan to reduce the workforce (approximately 6,000 employees), largely through attrition and managing vacancies, to help contain operating costs at the Utility.

Financial Profile

(CAD millions where applicable)	For the year ended March 31 1				
	2016	2015	2014	2013	2012
Cash receipts from customers	2,298	2,359	2,176	2,015	1,998
Cash paid to suppliers and employees	(950)	(1,203)	(1,053)	(981)	(1,048)
Interest paid	(580)	(517)	(502)	(489)	(418)
Interest received	23	26	70	44	35
Cash flow from operations	**791**	**665**	**691**	**589**	**567**
Dividends paid	0	0	0	0	0
Capital expenditures	(2,280)	(1,730)	(1,394)	(1,037)	(1,124)
Free cash flow	**(1,489)**	**(1,065)**	**(703)**	**(448)**	**(557)**
Acquisitions & investments	(89)	(105)	(103)	(98)	(90)
Net sinking fund withdrawals/(payments)	114	(3)	206	22	(75)
Net debt change	1,803	1,556	707	565	673
Other	123	(31)	3	(59)	29
Change in cash	**462**	**352**	**110**	**(18)**	**(20)**
Total debt (net sinking fund investments)	14,527	12,566	10,757	9,633	9,010
Cash and equivalents	953	487	142	32	50
Total debt in capital structure 2	83.0%	81.3%	79.4%	78.5%	77.9%
Cash flow/Total debt	5.4%	5.3%	6.4%	6.1%	6.3%
EBIT gross interest coverage (times)	0.91	1.07	0.96	0.89	0.80
Dividend payout ratio	0.0%	0.0%	0.0%	0.0%	0.0%

1 2015 to 2016 based on IFRS; 2012 to 2014 based on Canadian GAAP. 2 Adjusted for other comprehensive income.

F2016 Summary

- Manitoba Hydro's key financial ratios weakened in F2016 largely because of the increase in debt to fund the large capex requirements.
- Cash flow from operations increased in F2016 from higher payable balances related to the capex projects and to the lower cost of gas and purchase gas costs caused by warmer weather.
- Gross capex of $2.4 billion included $872 million for Bipole III and $742 million for the Keeyask Project.
- The significant free cash flow deficit for the fiscal period was funded through advances from the Province.

F2017 Outlook

- Manitoba Hydro's key financial ratios are expected to remain weak for the medium term as it continues its large capex program. While the debt-to-capital ratio had been forecast to peak at 88% in F2022, the Utility is currently reviewing potential initiatives to help improve its financial health.
  - Manitoba Hydro is seeking to identify internal efficiencies to improve operating results.
  - The Utility may request higher annual rate increases than the planned 3.95% in order to improve its earnings and cash flows.
  - A potential equity injection from the Province would also help alleviate pressure on Manitoba Hydro's leverage.
- Manitoba Hydro has forecast capex of approximately $3.5 billion for F2017, including around $1.5 billion for Bipole III and $1.1 billion for the Keeyask Project.
  - The Utility had forecast capex to peak in F2017 and F2018 ($3.1 billion) when Bipole III comes in service. It had also forecast capex to moderate to around $900 million a year following the in-service date of the Keeyask Project in F2021.
  - However, the BCG Report estimates that an additional approximately $1 billion may be needed for the two projects to be completed. As well, the BCG Report also expects delays to the in-service date of the two projects.
- The high level of capex is expected to result in continued negative free cash flows, which will likely be funded through advances from the Province. Without a corresponding increase in equity, either through higher earnings or an equity injection from the Province, the increasing debt load could further weaken Manitoba Hydro's key financial ratios.
  - The Utility does have some financial flexibility, as it has no mandatory dividend payment requirements.

Long-Term Debt Maturities and Bank Lines

		For the year ended March 31		
Debt Profile (CAD millions)	%	2016	2015	2014
Advances from the Province	98.8%	14,437	12,485	10,683
Manitoba Hydro Bonds	0.2%	26	76	169
Manitoba Hydro-Electric Board Bonds*	1.0%	145	157	158
	100.0%	**14,608**	**12,718**	**11,010**
Other adjustments		(81)	(38)	(142)
Total		**14,527**	**12,680**	**10,868**

* Includes $65 million of unguaranteed bonds at March 31, 2016.

Debt Maturities

Year	2017	2018	2019	2020	2021	Thereafter	Total
(CAD millions)	326	331	996	345	1,299	11,311	**14,608**
%	2%	2%	7%	2%	9%	78%	**100%**

Summary

- The Province supports Manitoba Hydro by advancing funds or guaranteeing the Utility's long-term debt issuances. Long-term debt at March 31, 2016, consisted of the following:
  - $14,437 million in advances from the Province (all of which have annual sinking fund requirements).
  - $26 million of Manitoba Hydro Bonds.
  - $145 million of Manitoba Hydro-Electric Board Bonds.
- Only $65 million of Manitoba Hydro-Electric Board Bonds, which were issued for mitigation projects, do not carry the provincial guarantee.
- Manitoba Hydro maintains a relatively smooth maturity profile with potential volatility from foreign currency debt, mostly mitigated through natural and cash flow hedges and a moderate level of floating-rate debt (10% of total debt at March 31, 2016), which adds stability to debt servicing costs and minimizes interest rate risk.
- The Utility has bank credit facilities that provide for overdrafts and notes payable of up to $500 million denominated in Canadian and/or U.S. dollars. At March 31, 2016, there were no amounts outstanding. Manitoba Hydro issues short-term promissory notes in its own name for its short-term cash requirements and does not receive short-term funding from the Province. These short-term notes are guaranteed by the Province.

Regulation

Manitoba Hydro is governed by *The Manitoba Hydro Act*, and its electricity and natural gas rates are regulated by the Public Utilities Board (PUB).

Electricity

- Each year, Manitoba Hydro reviews its financial targets with particular focus on its debt-to-equity target capital structure of 75% to 25%. If the Utility deems a rate adjustment necessary to continue progress toward attaining its financial targets, it submits a rate application to the PUB.
- The PUB reviews the rate adjustment application with the objective of allowing Manitoba Hydro to recover its cost of service and achieve its long-term debt-to-equity target. The PUB does not have the mandate to pre-approve capex. The capex planning responsibility resides with Manitoba Hydro and the government of Manitoba.
- Manitoba Hydro submitted its 2015/16 & 2016/17 General Rate Application (GRA) in January 2015, requesting 3.95% rate increases effective April 1, 2015, and April 1, 2016.
  - The PUB advised the Utility that it would not set rates for 2016/17 as part of this application.
  - On July 24, 2015, the PUB finalized the previously approved interim rate increase of 2.75% effective May 1, 2014, and approved a 3.95% increase in rates effective August 1, 2015. In its decision, the PUB indicated that it would consider various options regarding a process to review rates effective for April 1, 2016.
  - For the 2015 rate increase, the PUB directed 1.80% of the revenues associated with the rate increase to be applied to general revenues, and for the remaining 2.15% to be placed in a deferral account to mitigate rate increases when Bipole III comes in service. This was similar to the PUB's direction for rate increases approved in 2013/14 and 2014/15, where a portion of the revenues was also allocated to the Bipole III deferral account.
- On November 18, 2015, the Utility submitted its Supplemental Filing for Interim Rates effective April 1, 2016, requesting a 3.95% general rate increase.
  - In April 2016, the PUB approved an interim rate increase of 3.36% effective August 1, 2016.
  - Manitoba Hydro expects to file its 2016/17 and 2017/18 GRA in early 2017.
- While Manitoba Hydro is the sole retail electricity supplier in Manitoba, under *The Manitoba Hydro Amendment Act* (the Act), other utilities may access the transmission system to reach customers in neighbouring provinces and states.
- The Act also explicitly allows Manitoba Hydro to build new generating capacity for export sales, to offer new energy-related services, to enter into strategic alliances and joint ventures, and to create subsidiaries.
- There are presently no plans to move to full retail competition in the Province.
- Manitoba retail customers currently enjoy rates that are among the lowest in North America as a result of Manitoba Hydro's predominantly hydroelectric generation and efficient resource management.

Natural Gas Distribution

- Manitoba Hydro distributes natural gas through its wholly owned subsidiary, Centra Gas Manitoba Inc. (Centra Gas). In accordance with the rate-setting methodology for natural gas, commodity rates are changed every quarter based on 12-month forward natural gas market prices.
  - The commodity cost of gas is a pass-through with no markup to customers.
  - Non-commodity costs, such as transportation and storage are also passed on.
- The PUB allows Centra Gas to target an annual profit of approximately $3 million, which is fairly modest compared with Manitoba Hydro's consolidated earnings.
- Centra Gas filed its 2015/16 Cost of Gas Application in June 2015, requesting, effective November 1, 2015, the approval of supplemental gas, transportation and distribution rates, including rate riders to dispose of balances in its non-Primary Gas deferral accounts.
  - In October 2015, the PUB approved, on an interim basis, new rates for supplemental gas, transportation and distribution, as well as rate riders to dispose of the balance in the non-Primary Gas deferral accounts.

Watershed Storage Capacity

Manitoba Hydro draws water from five distinct watersheds: Nelson River, Winnipeg River, Saskatchewan River, Churchill River (including the Laurie River) and Burntwood River. This provides the Utility with some geographic diversification, especially during times of low hydrology. The main generation source is the Nelson River, which accounted for approximately 78% of power generated in F2016.

Source of Electrical Energy Generated and Imported

For the year ended March 31, 2016

Nelson River	**78.32%**
Billion kWh generated	**28.1**
Limestone	25.26%
Kettle	24.04%
Long Spruce	20.08%
Kelsey	6.62%
Jenpeg	2.32%
Winnipeg River	**10.45%**
Billion kWh generated	**3.8**
Seven Sisters	3.21%
Great Falls	2.31%
Pine Falls	1.75%
Pointe du Bois	0.80%
Slave Falls	1.15%
McArthur	1.23%
Thermal	**0.16%**
Billion kWh generated	**0.1**
Brandon	0.14%
Selkirk	0.02%

Saskatchewan River	**4.25%**
Billion kWh generated	**1.5**
Grand Rapids	4.25%
Laurie River	**0.10%**
Billion kWh generated	**0.0**
Laurie River #1	0.05%
Laurie River #2	0.05%
Burntwood River	**4.10%**
Billion kWh generated	**1.5**
Wuskwatim	4.10%
Purchases (excl. wind)	**0.24%**
Billion kWh imported	**0.1**
Wind	**2.38%**
Billion kWh	**0.9**

Source: Manitoba Hydro

Favourable characteristics inherent in Manitoba Hydro's watersheds include the following:

- Cold temperatures reduce overall evaporation rates, as many of the reservoirs are frozen over for up to five months of the year.
- A significant portion of the watersheds consists of rock, which has lower seepage rates and higher runoff than predominantly soil-covered watersheds.
- Lake Winnipeg, Cedar Lake and Southern Indian Lake serve as large storage reservoirs. The Utility's water storage capacity is a competitive advantage in trading electricity (buying surplus U.S. power at low off-peak prices and selling its electricity during peak demand periods at higher prices).

In addition to its own generating stations in Manitoba, Manitoba Hydro purchases all electricity from two wind farms in southern Manitoba (St. Joseph and St. Leon). The installed capacity of these facilities is 258.5 MW. The Wuskwatim Generating Station is owned by the Wuskwatim Power Limited Partnership, in which Manitoba Hydro is the majority owner. Manitoba Hydro purchases all the electricity generated from the Wuskwatim Generating Station.

Generating Capacity

Manitoba Hydro's Generating Stations and Capabilities

For the year ended March 31, 2016

Power Station	Location	# of Units	Net Capacity (MW)
Hydroelectric			
Great Falls	Winnipeg River	6	129
Seven Sisters	Winnipeg River	6	165
Pine Falls	Winnipeg River	6	84
McArthur Falls	Winnipeg River	8	56
Pointe du Bois	Winnipeg River	16	75
Slave Falls	Winnipeg River	8	68
Grand Rapids	Saskatchewan River	4	479
Kelsey	Nelson River	7	286
Kettle	Nelson River	12	1,220
Jenpeg	Nelson River	6	115
Long Spruce	Nelson River	10	980
Limestone	Nelson River	10	1,350
Laurie River (2)	Laurie River	3	10
Wuskwatim	Burntwood River	3	211
Total Hydroelectric Generation		**105**	**5,228**
Thermal			
Brandon (coal: 93 MW, gas: 234 MW)		3	327
Selkirk (gas)		2	125
Total Thermal Generation		**5**	**452**
Isolated Diesel Capabilities			
Brochet			3
Lac Brochet			2
Shamattawa			3
Tadoule Lake			2
Total Isolated Diesel Generation			**10**
Total Generation Capacity			**5,690**

Source: Manitoba Hydro

The Manitoba Hydro-Electric Board 1

Balance Sheet (CAD millions)	March 31 2016	2015	2014		March 31 2016	2015	2014
Assets				**Liabilities & Equity**			
Cash & equivalents	953	487	142	S.T. borrowings	0	0	0
Accounts receivable	372	427	520	Accounts payable	723	529	561
Inventories	117	99	81	Current portion L.T.D.	326	377	408
Prepaid expenses & other	43	54	0	Other current liab.	192	190	100
Total Current Assets	**1,485**	**1,067**	**743**	**Total Current Liab.**	**1,241**	**1,096**	**1,069**
Net fixed assets	17,208	15,222	13,627	Long-term debt (net sinking fund investments)	14,201	12,189	10,349
Goodwill & intangibles	301	290	281	Sinking fund investments	0	114	111
Investments & others	786	988	988	Other L.T. liab.	2,146	1,989	1,225
				Shareholders' equity	2,192	2,179	2,885
Total Assets	**19,780**	**17,567**	**15,639**	**Total Liab. & SE**	**19,780**	**17,567**	**15,639**

1 2015 to 2016 based on IFRS; 2014 based on Canadian GAAP.

Balance Sheet & Liquidity & Capital Ratios	For the year ended March 31 1 2016	2015	2014	2013	2012
Current ratio	1.20	0.97	0.70	0.48	0.65
Total debt in capital structure	86.9%	85.2%	78.9%	76.6%	75.8%
Total debt in capital structure 2	83.0%	81.3%	79.4%	78.5%	77.9%
Cash flow/Total debt	5.4%	5.3%	6.4%	6.1%	6.3%
(Cash flow-dividends)/Capex	0.35	0.38	0.50	0.57	0.50
Dividend payout ratio	0.0%	0.0%	0.0%	0.0%	0.0%
Coverage Ratios (times)					
EBIT gross interest coverage	0.91	1.07	0.96	0.89	0.80
EBITDA gross interest coverage	1.50	1.70	1.63	1.56	1.43
Fixed-charge coverage	0.91	1.07	0.96	0.89	0.80
Profitability Ratios					
Purchased power/Electricty revenues	6.5%	7.1%	8.6%	7.7%	9.3%
Operating margin	30.3%	31.5%	30.9%	30.2%	28.4%
Net margin	2.8%	7.3%	8.8%	4.9%	3.6%
Return on equity 2	1.9%	5.0%	6.6%	3.5%	2.4%

1 2015 to 2016 based on IFRS; 2012 to 2014 based on Canadian GAAP. 2 Adjusted for other comprehensive income.

Rating History

	Current	2015	2014	2013	2012	2011
Long-Term Obligations	A (high)	A (high)	A (high)	A (high)	A (high)	A (high)
Short-Term Obligations	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)

Note: These Obligations are based on the status of the Manitoba Hydro-Electric Board as a Crown agent of the Province of Manitoba and the unconditional guarantee provided by the Province on Manitoba Hydro's third-party debt, and thus reflect the Province's debt ratings.

Previous Action

- Confirmed, September 12, 2016.

Related Research

- *DBRS Confirms Province of Manitoba at A (high) and R-1 (middle)*, September 12, 2016.
- *Manitoba, Province of: Rating Report*, September 12, 2016.

Short-Term Promissory Notes Programme

- $500 million.

Previous Report

- Manitoba Hydro-Electric Board, The: Rating Report, November 26, 2015.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on **www.dbrs.com**.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

Rating Report

Province of Manitoba

DBRS

Insight beyond the rating.

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Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A (high)	Confirmed	Stable
Long-Term Debt*	A (high)	Confirmed	Stable
Short-Term Debt*	R-1 (middle)	Confirmed	Stable

* Includes guaranteed long-term and short-term debt obligations issued by the Manitoba-Hydro Electric Board.

Rating Update

DBRS Limited (DBRS) has confirmed the Issuer Rating and the Long-Term Debt and Short-Term Debt ratings of the Province of Manitoba (Manitoba or the Province) at A (high), A (high) and R-1 (middle), respectively. All trends are Stable. The Province's credit profile continues to be supported by a stable, resilient and growing economy and a debt burden that remains commensurate with the ratings. Notwithstanding this stability, the Province's operating results have failed to improve in recent years, and without a concerted effort to reduce operating deficits and slow debt accumulation, the flexibility within the existing ratings may be eroded.

Preliminary results for 2015–16 indicate that the deficit widened significantly to $1.0 billion from a budgeted deficit of $422 million. On a DBRS-adjusted basis, which recognizes capital expenditures as incurred as opposed to as amortized, this equates to a deficit of $2.0 billion, or 2.8% of gross domestic product (GDP). As a result, DBRS-adjusted debt is estimated to have risen to $27.6 billion, or 42.0% of GDP, as of March 31, 2016.

The economic outlook for 2016 remains largely similar to previous years. The Province expects reasonably strong growth in both 2016 and 2017, though forecasts have weakened slightly since the time of the budget. The private sector consensus tracked by DBRS suggests growth of 2.2% and 2.1% in 2016 and 2017, respectively. Continued gains in manufacturing and export-oriented industries are expected to offset weakness in residential and non-residential investment.

Despite consistent economic growth in recent years, the Province has posted increasingly large operating deficits. The newly elected PC Government tabled a budget within six weeks of election night. As such, the budget focuses on the current year and the expenditure plan is consistent with that of prior years. The budget projects a deficit of $911 million, or $1.75 billion on a DBRS-adjusted basis (2.6% of GDP). Initial indications from the new government suggest a reluctance to raise taxes or make sharp and immediate spending reductions. The focus appears to be on continuing to invest in strategic infrastructure and slowing expenditure growth without significantly affecting front-line services. With this, the government has indicated that it is unlikely to balance the budget until its second term in office (i.e., it could take up to eight years). DBRS estimates the debt burden will rise to $30.1 billion, or 44.1% of GDP, by the end of 2016–17 and expects it could climb further in subsequent years, though the trajectory is uncertain in the absence of a more detailed multi-year fiscal plan.

A negative rating action is not expected in the near term, but could occur if operating results deteriorate significantly and the outlook for debt burden increases sharply. A positive rating action, while unlikely, would require a material improvement in operating results and a substantial reduction in the debt burden.

Financial Information

	For the year ended March 31				
(all financial figures DBRS adjusted)	2016-17B	2015-16F	2014-15	2013-14	2012-13
Debt/GDP 1	44.1%	42.0%	38.8%	37.3%	36.0%
Surplus (deficit)/GDP	(2.6%)	(2.8%)	(2.1%)	(2.1%)	(2.2%)
Federal transfers/total revenue	27.0%	26.0%	25.9%	27.2%	29.2%
Interest costs/total revenue	5.5%	5.4%	5.4%	5.4%	5.6%
Real GDP growth rate 2	2.4%	2.2%	2.3%	2.4%	3.0%

1 Tax-supported debt + unfunded pension liabilities. 2 GDP on a calendar year basis as forecast in the provincial budget.
B = Budget. F = Forecast.

Issuer Description

Manitoba is located in Central Canada and ranks fifth among Canadian provinces by population and sixth in terms of GDP. The Province is home to significant renewable energy resources, with almost all electricity generated from water.

Rating Considerations

Strengths

1. Diversified and resilient economy

Manitoba has one of the most resilient and diversified economies in the country. The Province has a mix of industries, including agriculture, mining, manufacturing, financial services and transportation, with no undue reliance on a particular industry. The Province has a relatively stable labour force characterized by low unemployment, and relatively strong population and labour force growth. The Province's interprovincial and international exports are relatively diversified in both composition and destination. With this broad diversification, the Province's economy tends to post stable growth and exhibit lower volatility than the economies of most other provinces.

2. Prudent debt management

Manitoba's debt burden has risen sharply in recent years, reaching 42% of GDP at March 31, 2016. Notwithstanding the increases, the debt burden remains commensurate with the ratings, and the Province's approach to debt management is prudent. The Province maintains a relatively smooth debt maturity profile, no unhedged foreign currency exposure and only a moderate level of floating-rate exposure. The Province also has good market access with well-established domestic and international borrowing programs.

3. Abundant low-cost hydroelectricity

Manitoba benefits from an abundance of low-cost hydroelectricity. The Province has among the lowest rates in North America, which gives Manitoba a distinct advantage when competing for new business investment in some industries.

Challenges

1. Substantial deficit

The Province has a large deficit and few substantial revenue options available to it. As such, the Province will likely face significant challenges over the medium term to return to balance without affecting front-line services.

2. Reliance on federal transfers

Federal transfers, including equalization, account for about one-quarter of provincial revenue. Outside of Atlantic Canada, Manitoba is the most reliant province on federal transfers, which exposes it to some risk of federal policy changes, though DBRS notes that material changes to the major transfer programs tend to be gradual and well communicated. Moreover, DBRS also notes that Manitoba's share of the equalization program has fallen in recent years, which reflects an improvement in the Province's fiscal capacity relative to the other provinces.

3. Below-average income and GDP per capita

Manitoba boasts a well-diversified economy and a healthy labour market, though the Province continues to have lower average incomes, which limits the ability of the Province to significantly increase own-source revenue. DBRS notes that the Province's economy has grown moderately in recent years, and this includes relatively strong growth in per-capital GDP.

2016–17 Budget

Exhibit #1: Surplus (deficit)/GDP

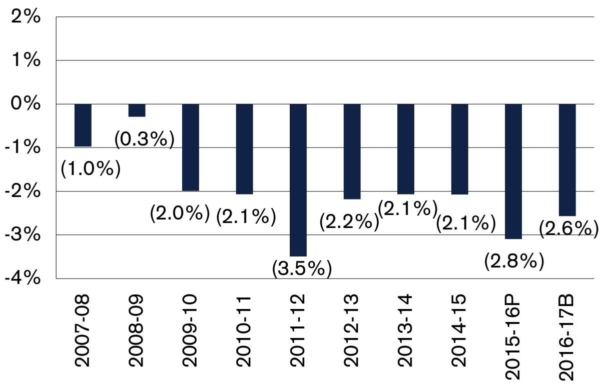
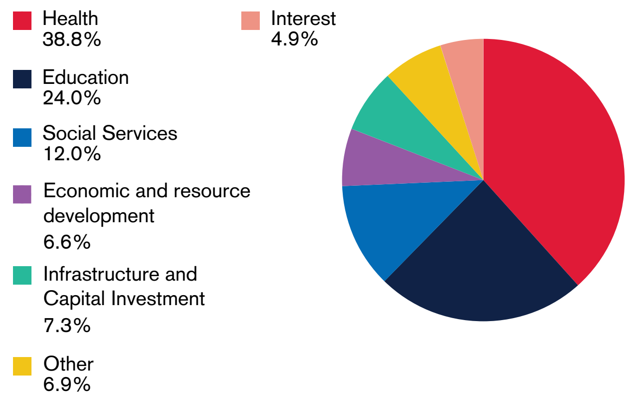


Exhibit #2: 2016-17 DBRS-Adjusted Expenditures



The newly elected Progressive Conservative government, led by Brian Pallister, introduced its first budget six weeks after being elected. The budget does not provide a multi-year outlook, but it does provide some insight into the government's longer-term fiscal and social policy objectives. Among its policy objectives, the budget speaks to restoring fiscal balance and discipline, limiting spending growth in core government, reviewing existing programs and continuing to invest in strategic infrastructure. A more substantive budget with a multi-year fiscal plan is expected in spring 2017.

The Province has projected a deficit of $911 million for 2016–17, which includes $150 million in unspecified revenue increases or expenditure savings. While it is a modest improvement over the prior year's preliminary result, it is one of the largest budget deficits for the Province and represents a significant challenge for the new government. On a DBRS-adjusted basis, the budget deficit equates to a $1.75 billion shortfall, or 2.6% of GDP.

Total DBRS-adjusted revenue is forecast to rise by 3.1% with moderate growth in tax revenue (+2.7%) and strong growth in federal transfers (+7.3%), which will offset some modest weakness in other own source revenue (-0.9%). Most of the revenue growth is attributable to underlying economic strength, though the government did begin to implement campaign promises with the partial indexation of the personal income tax system and the introduction of income testing for the Seniors' School Tax Rebate. Timing differences will provide a modest increase to revenue in 2016–17, but once fully implemented, the full-year net impact will be marginal.

Total DBRS-adjusted expenditures are budgeted to rise 1.1%, which includes a provision for $150 million in in-year savings. The budget includes fairly significant increases for health (+4.0%), education (+2.5%), social services (+4.6%) and justice (+3.1%). Much of the spending growth is being driven by both volume and cost pressures, though the Province has offset growth in these high pressure areas with significant reductions elsewhere in government, including economic development, general government and capital. As the spending plan has not significantly changed from previous years, it is likely that more substantive changes could be expected in the next budget, though the messaging from the elected government suggests a reluctance to significantly alter front-line services. The government has implemented an expenditure management process that could limit in-year spending increases and put a greater emphasis on doing more with less. While the potential savings may be limited, the new process does substantiate some of the shift in tone under the new government.

Capital investment remains significant but lower than in the prior year. The government will continue to invest in strategic infrastructure investments (e.g., roads, infrastructure, health care, education, etc.) and has committed to no less than $1 billion annually.

Outlook

The first budget was prepared quickly after the election and thus the spending plan was largely unchanged from previous years. DBRS expects the spring 2017 budget to provide greater clarity on the government's fiscal policy direction. The new government has emphasized its intention to restore the Province's finances but has indicated that it will be up to eight years before the budget is balanced. This reflects, in part, the limited revenue options available to the Province and the government's reluctance to adversely modify front-line services. As such, the strategy appears to be a slow grind back to balance, with the government seeking opportunities to slow expenditure growth, rationalize government services whenever possible.

To support this effort, the Province has initiated an enhanced expenditure management process and fiscal performance reviews. The expenditure management process requires greater oversight and approvals, and if sustained, could achieve modest savings through attrition and the avoidance of unnecessary

2016–17 Budget (CONTINUED)

expenses. The potentially more significant exercise appears to be the fiscal performance reviews, which are being conducted by a consultancy with the stated aim of improving the efficiency, efficacy and economy of government services. The challenge, however, is the constrained timeline required to complete thorough reviews, assess the findings, and implement the changes ahead of the next budget. While changes to tax systems or grants/transfers can be made relatively quickly, substantive changes to program areas generally require considerable lead time.

It is early in the new government's mandate, and while initial indications suggest the government is prepared to begin the process of fiscal consolidation, the challenge is considerable and the timeline is long. Without considerable upfront efforts to reduce near-term deficits, the Province's credit profile is likely to deteriorate further as a result of additional debt accumulation. While the Province's credit profile does have flexibility to accommodate ongoing deficits and the resulting growth in the debt burden in the near term, that flexibility is not unlimited. Without clear and credible action to demonstrate the government's resolve and to shift the outlook for debt growth, the credit rating could come under pressure over the medium term.

2015–16 Preliminary Results

Preliminary results for 2015–16 indicate that the budget deficit deteriorated significantly to $1.0 billion from the planned $422 million deficit. On a DBRS-adjusted basis, this equates to a $2.0 billion shortfall, or 2.8% of GDP. Total revenue rose marginally over the prior year but missed budget expectations primarily because of weaker-than-expected growth in tax revenue. Federal transfers rose slightly year over year; increases in Canada Health and Social transfers offset declines in equalization. Manitoba's equalization entitlement has been falling in recent years with the Province's improving fiscal capacity. On a per capita basis, Manitoba's entitlement has fallen to $1,344 from $1,591 over the last five years.

The deterioration in the operating result was largely driven by the significant increase in in-year spending. Budget projections suggested relatively little growth in DBRS-adjusted expenditures, but expenditures are projected to have been $700 million higher than planned, which contributed to relatively high year-over-year expenditure growth (+4.6%). The variance to budget was driven by health care and capital investment. Health-care spending was $162 million higher than planned as a result of price and volume pressures, while gross capital investment was about $144 million higher than planned. Other areas of government generally experienced more modest pressures or provided in-year savings.

Debt Profile

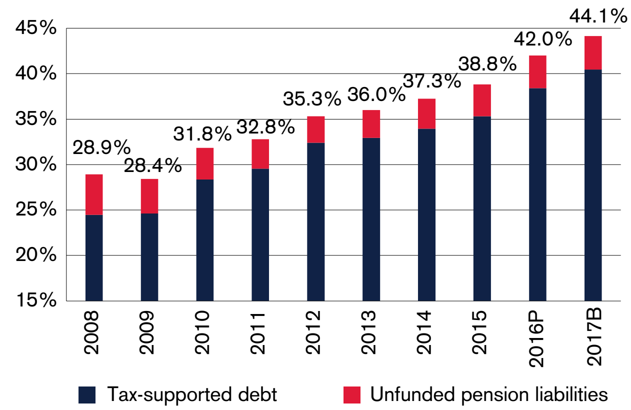
The Province's debt burden has continued to rise moderately with ongoing operating deficits and significant capital investment. DBRS estimates the Province's DBRS-adjusted debt burden, defined as tax-supported debt plus unfunded pension liabilities, to have risen by $2.8 billion in 2015–16 and reached 42.0% of GDP. This is about $1.5 billion, or 2.2% of GDP, higher than was anticipated at the time of DBRS's last review. The increase in the debt burden reflects both growth in outstanding debt and a negative revision to GDP.

The Province maintains a prudent debt structure with no unhedged foreign currency exposure and only moderate floating-rate exposure (18%) at March 31, 2016. The debt maturity profile remains relatively smooth with no substantial refinancing needs in any given year. Moreover, the Province has good market access with establish domestic and international borrowing programs.

The Province's unfunded pension liabilities are considerable and have continued to rise in recent years. At March 31, 2016, the unfunded pension liabilities totalled $2.3 billion, or 3.6% of GDP. The civil service superannuation plan and the teachers' pension plan account for the majority of the unfunded pension obligations. Contribution rates have increased in recent years, and indexing has been made conditional, though the unfunded liabilities have continued to rise in the absence of more substantial changes to plan design or funding.

The Province issues debt in its own name on behalf of the Manitoba Hydro, the provincial utility, and guarantees much of the utility's existing legacy debt. Notwithstanding the taxpayer-backed guarantee, both Manitoba Hydro and the Government of Manitoba expect the cost of this debt to be recovered through electricity rates. Manitoba Hydro is currently undertaking a significant capital program to increase capacity and reliability of its generation and transmission base. This is leading to a significant increase in debt, and because rate increases are being phased in gradually, leverage and coverage ratios are deteriorating. While the utility's financials are expected to deteriorate further over the medium term, leverage and coverage ratios will improve thereafter, and indications suggest that the rate increases will enable the utility to sustainably service its debt without direct subsidies from the Province. Moreover, the utility maintains considerable flexibility given its exceptionally low rates.

Exhibit #3: DBRS-Adjusted Debt-to-GDP



DBRS continues to classify Manitoba Hydro's debt as self-supported and excludes it from DBRS' estimate of tax-supported debt. DBRS would consider reclassifying a portion of Manitoba Hydro's debt as tax-supported if the outlook were such that the utility appears unable to service its debt with cash flow from operations for a sustained period of time.

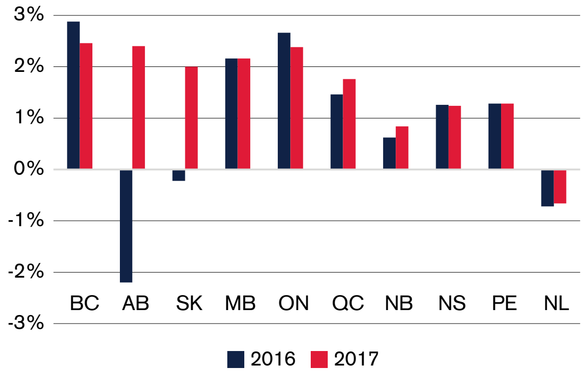
Outlook

In 2016–17, DBRS-adjusted debt is expected to rise by $2.5 billion to $30.1 billion on account of the budgetary deficit, capital requirements and rising unfunded pension liabilities. With the increase, the debt burden will rise to 44.1% of GDP, its highest level since the mid-1990s. The new government has stated its intention to stabilize the debt burden. In the absence of a more detailed fiscal plan and the long timeline for returning to balance, DBRS expects the debt burden to continue to rise over the medium term, though the trajectory and peak remain uncertain at this time.

The Province's gross borrowing requirement for 2016–17 is estimated to be $6.5 billion, of which the Province has already completed $2.4 billion. The Province typically targets 30% of its issuance outside of Canada, but has been borrowing more heavily in international markets this year.

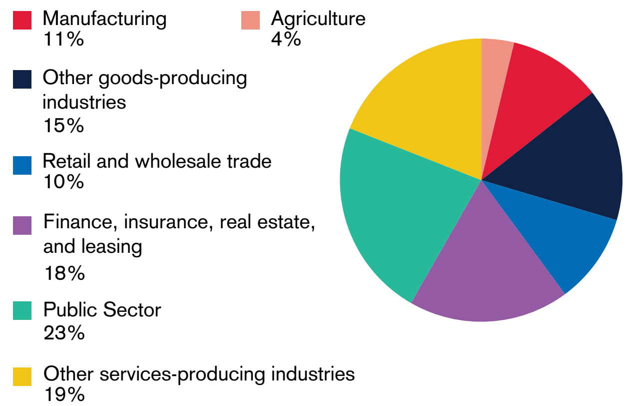
Economy

Exhibit #4: Real GDP Growth Outlook



Source: Major Canadian banks' economic forecasts at the time of this report.

Exhibit #5: 2015 Real GDP Breakdown



Source: Statistics Canada, CANSIM 379-0028.

Preliminary estimates from Statistics Canada indicate that Manitoba's economy grew by 2.3% in 2015, with fairly strong growth across both the goods and services producing sectors. The results were somewhat mixed among industries: Strong growth in construction, agriculture, transportation and warehousing, and financial services offset weakness in mining, oil and gas, and the public sector. Manitoba's economy is relatively stable given its broad diversification.

Overall manufacturing and exports showed mixed results, with agricultural exports (food and equipment) showing some weakness given the strength of the prior-year crop and weaker exports to some markets. Notwithstanding this softness, exports in the transportation, electronics, metals and energy industries did post reasonable growth, in part supported by an improving U.S. economy and a weaker Canadian dollar.

The labour market continued to perform well with a modest increase in unemployment, reflecting stronger growth in the labour market. Both the labour market (+1.8%) and employment (+1.5%) grew moderately, with employment gains largely driven by the private sector. Overall growth in the labour market continues to reflect strong underlying population trends. Manitoba continues to benefit from strong population growth driven by natural increase and international migration. Moreover, weakness in commodity-producing provinces has reduced interprovincial outflows. Altogether, Manitoba expects reasonably strong population growth to continue over the medium term.

Relatively strong household formation has supported strong gains in the housing market in recent years. This led to overbuilding in the years leading up to 2015, which weighed on residential construction in 2015. Despite the excess housing stock, housing market fundamentals have held up well, as the excess inventory is being absorbed. Non-residential investment more than offset weakness in the housing market, as a number of major projects were underway in 2015 (e.g., Canadian Museum for Human Rights, Stadium, Hydroelectric projects, and infrastructure).

Outlook

At the time the budget was presented, the Province projected real economic growth of 2.2% in 2016 and 2.4% in 2017. This is consistent with growth in recent years and the private sector expectations at the time of the budget. The economic outlook has since weakened marginally, though the Province and private sector forecasters continue to expect growth of at least 2.0% in this year and next. Overall, the economic outlook is stable with continued gains in export-oriented industries supporting moderate growth. The Province will continue to see moderately strong population growth, as international migration remains strong and interprovincial outmigration remains subdued, which will support further growth in the labour market. The economic forecast has relatively little upside potential given the completion of a number of major construction projects recently, though there is some downside risk to the outlook with the modestly slower growth outlook for the U.S. economy and a potentially weaker harvest as a result of the wetter-than-normal growing season. Notwithstanding the downside risks, the economic outlook for the Province continues to exhibit significant stability and resilience.

Economy (CONTINUED)

Economic Statistics

	For the year ended December 31						
	2017 P	2016 P	2015	2014	2013	2012	2011
Nominal GDP ($ millions)	71,313	68,308	65,807	64,077	61,897	59,781	56,197
Nominal GDP growth	4.4%	3.8%	2.7%	3.5%	3.5%	6.4%	5.4%
Real GDP growth	2.4%	2.2%	1.6%	2.3%	2.4%	3.0%	2.5%
Population (thousands)	1,323	1,309	1,293	1,280	1,265	1,250	1,234
Population growth	1.1%	1.2%	1.0%	1.2%	1.2%	1.4%	1.0%
Employment (thousands)	646	639	636	627	626	622	612
Unemployment rate	5.5%	5.8%	5.6%	5.4%	5.4%	5.3%	5.5%
Housing starts (units)	5,700	5,350	5,501	6,220	7,465	7,242	6,083
Retail sales ($ millions)	19,823	19,377	18,297	18,034	17,297	16,652	16,443
Inflation rate (CPI)	2.2%	1.8%	1.2%	1.9%	2.2%	1.6%	3.0%
Primary household income per capita ($)	34,141	33,675	33,509	32,210	31,687	30,822	29,605

Sources: Statistics Canada (actuals); Manitoba Finance and DBRS estimates; CMHC (housing projections). P= Projected.

Budget Summary

	Projected		Budget			
($ millions)	2016-17	2015-16	2015-16	2014-15	2013-14	2012-13
Revenue	15,190	14,729	14,912	14,691	14,152	13,540
Program expenditure	16,110	15,794	15,270	15,227	14,672	14,080
Program surplus (deficit)	**(920)**	**(1,065)**	**(358)**	**(536)**	**(520)**	**(540)**
Interest expense	834	790	790	794	759	765
DBRS-Adjusted Surplus (Deficit)	**(1,754)**	**(1,855)**	**(1,149)**	**(1,330)**	**(1,279)**	**(1,305)**
DBRS adjustments:						
Capital expenditures less amortization 1	843	844	727	877	757	745
Surplus (deficit), as reported	**(911)**	**(1,011)**	**(422)**	**(453)**	**(522)**	**(560)**
Tax-supported debt + unfunded pension liabilities	30,143	27,635	26,169	24,872	23,057	21,515
Gross borrowing requirements (all entities)	6,500	6,309	4,725	5,357	4,528	3,493
Gross capital expenditure	1,517	1,702	1,331	1,534	1,333	1,273

1 DBRS adjusts reported figures to recognize capital expenditures as incurred rather than as amortized, to improve interprovincial comparability.

Selected Financial Indicators (DBRS-Adjusted)

	2016-17	2015-16	2015-16	2014-15	2013-14	2012-13
Debt/GDP 1	44.1%	42.0%	39.8%	38.8%	37.3%	36.0%
Surplus (deficit)/GDP	(2.6%)	(2.8%)	(1.7%)	(2.1%)	(2.1%)	(2.2%)
Surplus (deficit)/total revenue	(11.6%)	(12.6%)	(7.7%)	(9.1%)	(9.0%)	(9.6%)
Interest costs/total revenue	5.5%	5.4%	5.3%	5.4%	5.4%	5.6%
Total tax revenues/total revenue	52.7%	52.9%	53.5%	51.6%	50.7%	49.2%
Federal transfers/total revenue	27.0%	26.0%	26.0%	25.9%	27.2%	29.2%
Program expenditures/total revenue	106.1%	107.2%	102.4%	103.6%	103.7%	104.0%
Health expenditures/total expenditures	38.3%	37.3%	37.9%	37.3%	37.0%	36.7%
Program expenditure growth	0.8%	3.7%	0.3%	3.8%	4.2%	(5.1%)
Total expenditure growth	1.1%	3.5%	0.2%	3.8%	3.9%	(4.8%)
Total revenue growth	3.1%	0.3%	1.5%	3.8%	4.5%	(0.6%)

1 DBRS-adjusted debt: tax-supported debt + unfunded pension liabilities.

Political Background Information

Party in Power:	Progressive Conservative Party	**Legislature Seats:**	40 of 57
Premier:	Brian Pallister	**Election required by:**	October 2020

DBRS-Adjusted Statement of Operations

($ millions)

	Projected		Budget			
	2016-17	**2015-16**	**2015-16**	**2014-15**	**2013-14**	**2012-13**
Revenue						
Personal income tax	3,339	3,261	3,262	3,117	2,978	2,846
Retail sales tax	2,328	2,261	2,292	2,205	2,028	1,767
Corporate taxes	1,123	1,093	1,220	1,105	1,024	965
Fuel taxes	331	327	346	335	329	332
Tobacco taxes	256	256	252	256	272	252
Education property tax	533	500	493	461	434	380
Other taxes	93	95	108	101	105	124
Total tax revenue	**8,003**	**7,794**	**7,973**	**7,578**	**7,169**	**6,667**
Manitoba Liquor and Lotteries Corporation	586	583	582	597	554	558
Manitoba Hydro	42	49	125	114	174	92
Natural resource levies	152	169	172	169	176	168
Fees, permits, licences & other	2,299	2,306	2,178	2,425	2,237	2,102
Total Own-Source Revenue	**11,082**	**10,901**	**11,031**	**10,883**	**10,310**	**9,587**
Equalization payments	1,736	1,738	1,738	1,750	1,799	1,872
Canada health & social transfer	1,786	1,697	1,698	1,621	1,524	1,487
Other federal transfers	586	393	445	438	519	594
Total Federal Transfers	**4,108**	**3,828**	**3,881**	**3,809**	**3,842**	**3,953**
DBRS-Adjusted Revenue	**15,190**	**14,729**	**14,912**	**14,691**	**14,152**	**13,540**
Expenditures						
Health	6,497	6,250	6,088	5,979.9	5,706	5,454
Education and training	4,061	3,962	3,983	3,638.5	3,562	3,339
Social services	2,036	1,946	1,891	1,119.6	1,074	1,035
Justice	603	585	581	532.7	534	500
Infrastructure and transportation	389	269	373	544.3	501	540
Economic and resource development	1,115	1,168	1,109	1,997	1,914	1,883
Other general government	716	770	668	538	624	584
Capital expenditures less amortization 1	843	844	727	877.0	757	745
Targeted in-year savings	(150)	-	(150)	-	-	-
DBRS-Adjusted Program Expenditures	**16,110**	**15,794**	**15,270**	**15,227**	**14,672**	**14,080**
Net interest expense 2	834	790	790	794	759	765
DBRS-Adjusted Expenditures	**16,944**	**16,584**	**16,060**	**16,021**	**15,431**	**14,845**
DBRS-Adjusted Surplus (Deficit)	**(1,754)**	**(1,855)**	**(1,149)**	**(1,330)**	**(1,279)**	**(1,305)**
DBRS adjustments:						
Capital expenditures less amortization 1	843	844	727	877	757	745
Surplus (deficit), as reported	**(911)**	**(1,011)**	**(422)**	**(453)**	**(522)**	**(560)**

1 DBRS adjusts reported figures to recognize capital expenditures as incurred rather than as amortized, to improve interprovincial comparability.
2 Interest expense is net of sinking funds.

Province of Manitoba

Statement of Financial Position

($ millions)	2017B	2016P	2015
Assets			
Cash and cash equivalents	5,693	7,863	6,728
Amounts receivable	4,259	4,405	6,466
Loans & advances 1	32,172	32,712	30,703
Equity in gov't enterprises	3,829	3,692	3,415
Net tangible capital assets	18,023	17,217	15,796
Other assets	49	188	151
Total Assets	**64,025**	**66,077**	**63,259**

	2017B	2016P	2015
Liabilities			
A/P and accrued charges	4,200	4,204	4,204
Debt 1	45,547	39,874	35,742
Unfunded pension liability	2,513	2,354	2,245
Total Liabilities	**52,260**	**46,432**	**42,191**
Accumulated Deficit	**(9,685)**	**(8,812)**	**(7,923)**

Net Public Sector Debt

	As at March 31							
($ millions)	2017B	2016P	2015	2014	2013	2012	2011	2010
Net general purpose debt 2	19,714	18,499	16,784	15,730	14,851	13,956	11,907	10,949
Crown corporation & gov't agencies	3,710	3,309	2,827	2,511	2,246	1,926	1,641	1,478
Schools and universities	610	620	610	590	538	495	461	432
Health facilities	2,473	1,730	1,338	1,262	1,149	1,094	1,015	949
Municipalities 3	1,123	1,123	1,068	926	903	735	723	602
Net Tax-Supported Debt	**27,630**	**25,281**	**22,627**	**21,019**	**19,687**	**18,206**	**15,747**	**14,410**
Self-supporting debt:								
Manitoba Hydro 2	17,848	14,544	12,540	10,838	9,609	8,999	8,362	7,730
Total net public sector debt	**45,478**	**39,825**	**35,167**	**31,857**	**29,296**	**27,205**	**24,109**	**22,140**
Unfunded Pension Liabilities 4	2,513	2,354	2,245	2,038	1,828	1,634	1,731	1,768
DBRS-Adjusted Debt 5	**30,143**	**27,635**	**24,872**	**23,057**	**21,515**	**19,840**	**17,478**	**16,178**
Per Capita (CAD)								
Tax-supp. debt + unf. pension liabilities	23,029	21,366	19,427	18,222	17,206	16,082	14,316	13,386
Total public sector debt	34,745	30,791	27,469	25,176	23,429	22,051	19,747	18,319
As a % of GDP								
Tax-supp. debt + unf. pension liabilities	44.1%	42.0%	38.8%	37.3%	36.0%	35.3%	32.8%	31.8%
Total public sector debt	66.6%	60.5%	54.9%	51.5%	49.0%	48.4%	45.2%	43.6%
Debt Breakdown by Currency 6								
CAD pay	n/a	100%	100%	100%	100%	100%	100%	100%
Non-CAD pay	n/a	0%	0%	0%	0%	0%	0%	0%
Fixed/Floating Rate Debt Breakdown 6								
Fixed rate	n/a	82%	78%	79%	77%	80%	76%	82%
Floating rate	n/a	18%	22%	21%	23%	20%	24%	18%

1 Includes the assets and liabilities related to debt of Manitoba Hydro and Manitoba Lotteries Corporation. 2 Excludes pre-financing. 3 Not guaranteed by the Province.
4 Excludes pension liabilities for self-supporting Crown corporations. 5 DBRS-adjusted debt is defined as tax-supported debt plus unfunded pension liabilities (excluding those of self-support Crown corporations. 6 Net of hedges (if any). Floating-rate debt is defined as debt that matures or is reprised within 12 months.

Unfunded Pension Liabilities (Tax-Supported)

($ millions)	Valuation Date	Mar. 31, 2016
Civil service 1	Dec. 2015	2,813
Teachers 2	Jan. 2012	3,589
Other plans (incl. MLAs, judges, other)	Various	1,912
Total liabilities		**8,314**
Pension assets		5,960
Total Unfunded Pension Liabilities		**2,354**

1 Civil service pension plan includes amounts for indexation and unamortized pension adjustment. 2 Teachers' pension plan includes amount for indexation.

Gross Debt Maturity Schedule

($ millions)	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22 to 2025-26	2026-27 +	Total
Public Sector Debt ($ millions)	4,307	2,497	2,727	2,405	3,527	8,165	15,988	39,615
Public Sector Debt (%)	10.9%	6.3%	6.9%	6.1%	8.9%	20.6%	40.4%	100.0%

Rating History

	Current	2014	2013	2012	2011	2010
Issuer Rating	A (high)	A (high)	A (high)	A (high)	NR	NR
Long-Term Debt	A (high)	A (high)	A (high)	A (high)	A (high)	A (high)
Short-Term Debt	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)	R-1 (middle)

Previous Action

- Confirmed, August 17, 2015.

Related Research

- *Rating Canadian Provincial Governments,* May 25, 2016.
- *DBRS Criteria: Guarantees and Other Forms of Support,* February 9, 2016.
- *Manitoba Hydro-Electric Board: Rating Report,* August 17, 2015.

Treasury Bill Limit

- $1.95 billion.

Previous Report

- Province of Manitoba: Rating Report, August 17, 2015.

Notes:
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on **www.dbrs.com**.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

TAB 4

Excerpts - Moody’s Credit Opinion – MHEB, dated November 28, 2017. Exhibit MH-61

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LOW RATES IN A STABLE ECONOMIC ENVIRONMENT

Manitoba Hydro operates in a stable regulatory framework with steady yearly rate increases. It had an interim rate increase of 3.36% effective from August 1, 2017 that will flow into the Bipole III deferral account. While rates increases are nominally set on a cost-of-service basis rate increases in recent years have clearly not kept up with costs as evidenced by ongoing weak financial metrics. The MPUB independently oversees the rate setting process and has a supportive environment for cost recovery. Residents in Manitoba continue to pay rates that are among the lowest in North America. Revenues from exports to the US and other Canadian provinces accounts for over 20% of electric revenue, alleviating pressure to increase rates and contributing to the current low rates in the Province.

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FINANCIAL TARGETS TO BE CHALLENGED BY HIGHER CAPEX

As part of its debt management strategy, Manitoba Hydro targets certain financial metrics such as an interest coverage ratio greater than 1.8x and equity-to-capitalization greater than 25%. However, both targets are not expected to be met for an extended period of time due to the large generation and transmission projects currently underway such as Keeyask and Bipole III and limited rate increases. For example on a last twelve month basis Moody's adjusted EBITDA to interest expense was 1.3x and debt to book capitalization was 88%. These financial metrics are among the weakest, if not the weakest, of any of Manitoba Hydro's peers, including vertically

integrated provincially owned crown corporations in Canada. Total capital expenditures are forecasted to be around $12.2 billion, or on average $2.4 billion per year from FY2018 to FY2022.

The weakening financial profile restricts financial flexibility and adds risk in case of unexpected events such as low water levels, cost overruns and construction delays given the nature of a hydroelectric plant's long construction cycle prior to the start of operations and cash flow. Offsetting these risks, we view Manitoba Hydro as benefiting from access to funding from the Province and seeking rate increases and curtailing capital spending to continue as a self-supporting corporation.

TAB 5

Decarbonization through electrification is critical to achieving climate change targets. Manitoba and Canada have benefitted from our early investments in clean energy. We are well positioned to provide reliable, clean energy to other jurisdictions as they too begin to shift away from fossil fuels towards prosperous low-carbon economies.

Manitoba already exports clean energy across the border to Minnesota and Wisconsin, reducing emissions in those states. Exporting our clean energy to our neighbouring province Saskatchewan via a new western electricity grid would reduce fossil fuel energy use in that province and help Canada achieve its overall emissions reduction targets. In January 2016, Manitoba Hydro and SaskPower agreed to a 20-year, 100 MW power sales agreement, which could lead to annual reductions of approximately 200,000 to 400,000 tonnes of carbon dioxide in displaced Saskatchewan electricity emissions. Federal financial support for a new and even larger transmission line could result in annual emissions reductions of about three megatonnes of carbon dioxide in Saskatchewan by using clean Manitoba hydro electricity.

Decarbonization refers to the current trend to shift energy use from fossil or carbon-based fuels to clean energy sources.

Efficiency Manitoba

Manitoba's clean energy advantage puts us solidly on the path to a prosperous, low-carbon economy. But there are also advantages to using our energy resources more wisely and efficiently right now.

Manitoba winters are cold and many Manitobans rely on carbon-emitting natural gas furnaces to stay warm. Annually, Manitoba consumes around 1.6 billion cubic metres of natural gas, which translates to approximately 3,000 kilotonnes of carbon dioxide. Manitoba has introduced legislation to create a new energy-saving demand-side management agency known as Efficiency Manitoba. This new stand-alone agency will help households and businesses reduce their energy consumption and save money on their electricity bills. That means lower energy and Hydro bills and more jobs.

By reducing electricity and natural gas consumption through targeted programming, Efficiency Manitoba will realize legislated targets of an 11.25 per cent reduction in domestic natural gas demand and a 22.5 per cent reduction in domestic electricity demand over a 15-year period. The natural gas savings would translate into GHG emissions reductions of approximately 2,700 kilotonnes over a 15-year period. It will be up and running in 2018.

Demand-side management refers to energy conservation and efficiency activities designed to reduce the demand for energy and electricity as well as using more green heat.

Green Heating

Heat is often the single largest reason we use energy in our society. In Manitoba, building and water heating consumes roughly one third of energy use and represents the majority of emissions attributed to the operation of buildings.

TAB 6

about the time that's available to this panel before it recesses for an extended period of time.

I'd like to get the evidence in from your witness before the end of the day tomorrow. And at the pace we're going, I'm concerned that we won't get that done. I wonder if, over the lunch hour, in terms of -- of -- my concern is making sure that we get disputed issues on the table and discussed. And -- and so far, we have -- we have not done that.

And so I'm worried, in terms of how we get to that and get that completed before the end of the day. And we can go back and discuss, sort of, basic principles, which I think will surface in -- in some of the -- the areas that are being challenged by -- by MIPUG, in terms of the rate application, as a byproduct of -- of a discussion of the disputed matters.

So -- so to the first question: Can we -- can we complete this discussion of -- of rate-setting principles before we break for lunch in a relatively short period of time? And then second -- the other question is: Do you object to -- to the approach I'm suggesting with respect to addressing the -- the disputed areas of the Application?

MR. ANTOINE HACAULT: My expectation,

members of the Board, is that we will finish Mr. Bowman's direct testimony prior to 4:30. I -- I would have thought it's -- we had an initial motion this morning; I think we would have been well into his other evidence by now. But my full expectation is that -- I was looking through the notes. We're about halfway through the presentation. There's been quite a few questions. So that we'd spent about an hour and a half this morning on the presentation, and I would expect another hour and a half to two (2) hours would complete the presentation,

THE CHAIRPERSON: Given that, why don't we adjourn now for -- for lunch and -- and resume the proceedings -- sorry, why don't we recess now and resume our proceedings at 1 o'clock? Thank you.

--- Upon recessing at 12:03 p.m.
--- Upon resuming at 1:01 p.m.

THE CHAIRPERSON: Good afternoon. We're ready to resume the proceedings. Mr. Hacault...?

MR. ANTOINE HACAULT: Thank you, Mr. Chair.

CONTINUED BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: Mr. Bowman, could you address the -- the in -- issue of interest rate risk and setting up reserves?

MR. PATRICK BOWMAN: Yes. Good afternoon. The notes that I have on this relate to the fact that, building where we were this morning, the premise of trying to set the rates for a utility such as this is to find the -- the level that can be sustainable generally over time so that things that are cyclical, like droughts and floods, or some of those other things that are -- that can affect it on a short-term or a medium-term basis, don't lead to rate shocks.

Interest rate risk is a -- is a little bit different. It's a little bit different partially because most of the debt at any given time is locked in. And it's a little bit different because it's not necessarily quite the same cyclical mean-reverting nature as water flows.

But if -- if interest rates make a move -- move up, for example -- for a period of time that leads to hydro refinancing debt at a higher level, you know, on a normal operating basis, then it's a perfectly reasonable set of circumstances that lead to rates moving up.

It's -- it's not necessarily the -- the

kind of feature that you'd worry about trying to set aside some reserves to protect against, because it's exactly the kind of feature that is a recoverable cost for the utility and is a -- is a reasonable basis for -- for rate changes, whether that's up -- upward or downward movements.

MR. RAYMOND LAFOND: I -- I'd like to make a comment on that. If, for instance, a new project like Wuskwatim wa -- was financed at 6 percent for thirty (30) years, come thirty (30) years' time, the interest rates are 16 percent for -- to renew it for twenty (20) years.

That would be a real interest -- that would be a real rate shock because interest rates -- or interest -- finance expense make up two thirds (2/3s) of the cost?

MR. PATRICK BOWMAN: Yes, I agree. I'd sort of make two (2) corollaries to it. One (1) is I'm not sure anyone would -- well, let me go back a step. First, I think you'd want to be looking at the -- as Hydro does, at a portfolio of debt and maybe not necessarily the -- the debt associated with one (1) -- with one (1) project.

And -- and even if you were dealing with either a portfolio or -- or even a subset of the

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portfolio, you -- for those reasons, you'd -- you'd still want to have a sensible treasury type of policy about exposure to rates by using different -- different maturity dates so that you're not necessarily having a whole bunch of debt turning over at the same date. That -- that certainly gives you an acute risk if that -- if that does occur.

And that's why, with my comments I said on a normal basis, if interest rates move up any given year, you're going to be refinancing some of your debt. That will drive your costs up somewhat. You come back. You work your way through higher rates. And that is the way the system's meant to work.

When it comes to very lar -- ma -- very major projects, it definitely is a different situation. And -- and when you look in those risk tables that we provided in the MIPUG book of documents about interest rates risk now it's magnitudes higher than it was two (2) or three (3) years ago, because the horizon is now picking up the major projects.

But that's not -- that's not necessarily a risk that's inherent in -- in the -- what I call the status quo IFF or the basic operations of Hydro. That -- that's a risk that definitely fits more in the -- the bucket of the sort of NFAAT type of issues and that

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really needs serious thought.

You gave the example earlier of the project in -- in Mayo and why it was able to come in on time and on budget. Well, one (1) of the reasons we were able to make that happen was because of schedule management. The -- the project was smaller. It was -- it didn't involve new water conveyance system -- or new water retaining systems. There was already a dam there. We added a penstock and turbine and expanded the capacity of it by 10 megawatts.

And the project was being assessed in 2007. The decision was made to proceed with the project to an advancement schedule in the middle of 2008, which is when some -- most of the cost esta -- estimating was done. We filed for environmental approvals in early 2009. They had shovels in the ground by 2010. And the project was in service at the very end -- Christmas 2011.

So one of the ways you manage risk on a project, or you manage cost escalation, is you keep your -- your schedule contained. And -- and it's --

MR. RAYMOND LAFOND: I -- I understand that, but I'm trying to see a relationship with interest rates.

MR. PATRICK BOWMAN: Well, I'm saying

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the same is true for interest rates. The -- the -- if you're sitting, having a -- if you're sitting --

MR. RAYMOND LAFOND: No, but on interest rates, you -- you said there were no reserves required. My knowledge in the banking industry, they require equity for the purposes of absorbing, amongst other things, interest rates escalations, which can be fairly serious on a project that's so capital intensive, because that's the major portion of it.

MR. PATRICK BOWMAN: Right. So let me go back a step, because I would -- I would put this in -- in two (2) categories, and I think they each have a bit of a different story to them.

So under a normal operations category, a base case IFF where you're -- you are building what you need to, you're doing a least-cost capital plan, and you're assessing rates in a test year over a few years, your interest rate risk is not immense because most of your debt is fixed at long term. It only turns over slowly.

And -- and for your banker looking at your statements, you're different as a regulated utility who can raise the rates than you are as a company who can't raise its rates, who's -- who's fixed in the market.

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So if you're -- if you're financing, take a pick -- Home Depot and you're loaning them money, then you want to see that --

MR. RAYMOND LAFOND: Yeah, I -- I think I understand all this.

MR. PATRICK BOWMAN: Yeah.

MR. RAYMOND LAFOND: I'm just -- I'm just questioning the premise of why no retained earnings would be -- need to be accumulated to a certain extent to cover off finance risks?

MR. PATRICK BOWMAN: Sorry. It's possible I'm -- I'm misunderstanding the question, because I was -- it -- there's a -- there's a set of interest rate risks that relate to the ongoing normal IFF, and there's a set --

MR. RAYMOND LAFOND: Well, maybe I did --

MR. PATRICK BOWMAN: -- of interest rate risks that were --

MR. RAYMOND LAFOND: Maybe I did not understand your premise. I think I heard that we needed to accumulate retained earnings for the purposes of -- of avoiding major rate changes or vol -- volatile rates due to droughts, but that that was not needed for interest rates.

And I'm saying: Why would not a certain level of retained earnings be required to soften up the blows of interest rates incre -- increasing substantially in the near future?

MR. PATRICK BOWMAN: Well, some -- some level of reserves could soften, but it's not serving a function like a drought, to offset something that's good some years and bad others. The interest rates are already softened and absorbed into Hydro's system because they do long-term borrowing, because they only turn over so much debt in the absence of the major projects, because they only do -- turn over so much debt every year, and because they use a long-term debt portfolio and most of their interest rates are fixed.

That would tend to mean that when your interest rate starts to move, your -- your cost levels shift perhaps in a fairly significant way, but over time, and -- and your cost transition to a different level, a higher level. And your rates can move over that same time to transition.

I'm saying that -- making a distinction between that and something like -- like droughts where you can have --

MR. RAYMOND LAFOND: Okay. I understand the droughts. But we -- we heard earlier

this week that the policy of Manitoba Hydro is to maintain 15 to 30 percent of their debt portfolio in variable rates; in other words, demand rates. So if rates go up by 3 percent, 30 percent of the portfolio goes up by 3 percent.

Am I correct?

MR. PATRICK BOWMAN: Well, the -- the part I would have focussed on was what they were actually maintaining and whether that's a sensible proportion to maintain. My general experience with -- with these type of -- of utilities is that you would try to maintain as -- you know, a very high percentage in -- in fixed rates. You might keep some percentage in short-term, which is what I understand Manitoba Hydro is looking to do. You know, to -- 15 percent is the number that -- that I've seen recently in variable.

But there's sort of a technical reason for that, which is you actually end up with an overall lower cost of debt by keeping some in short-term, and you can actually reduce your risk of variability from year to year by keeping some in short term because you start to see the effects of rate changes a little bit sooner. So you don't get just walled by big refinancings. You -- you -- you get some of that eased into your system. And -- and as that eases into your

system, that's exactly the kind of reasons why you would come back and say, Our overall cost level has changed, let's change rates now.

I'm making a distinction that that's not a reason why you would come and say, Our cost levels might change in the future, and so let's all get together and decide that -- that ratepayers should now pay a higher level of rates, take money out of the economy, take -- take the impacts of higher rates because -- because interest could go up, and -- and so sort of pre -- pre-fund the interest expense in that year.

Interest expense in that year is a valid component of rates, and -- and it will be -- it could be readily part of a change to rates at that time. Other than perhaps some -- some limited aspects that are for, you know, transition to help avoid the rate shocks.

But it -- it would take -- outside of the major projects, it would take a heck of a short and a heck of a steep interest rate price change to be -- have Hydro coming in here and saying, it's -- We now need to shock our customers.

MR. RAYMOND LAFOND: Okay. Thank you. I've heard.

CONTINUED BY MR. ANTOINE HACAULT:

MR. ANTOINE HACAULT: So, Mr. Bowman, is part of that, that your capital also, on the long-term projects, continues to be spent over a long time period? For example, we're looking at Conawapa late around 2026, and there's already some capital spending. And that capital spending continues on an ongoing basis. That, together with the biannual -- so every two (2) years -- you're looking at the interest costs.

Is that part of what we're considering, as far as a transition to slowly perhaps increase reets -- rates to meet any increased interest rates?

MR. PATRICK BOWMAN: Right. Your -- your goal in setting rates for a cost-of-service-based utility like this would be to strike a level of rates that reflects the underlying costs and that is able to absorb things like cyclical changes and -- and to some extent, absorb the -- the shock of changes when -- when there's material changes in cost levels.

If your costs are up -- and this is the same argument that I was making in the EIIR hearing. If something happens like your -- in that case, if you had your load grow because customer demands went up and you lost some export revenues and you had to hook up new customers here and it wasn't generating the same amount of revenues as your exports, that's a valid component of a changing cost that you'd work to build into rates. If your interest rates went up, that's a valid component of the change in costs of that underlying system that you want to build into rates. And rates should -- should work to strike a new stable level and -- and -- and move their way there. That -- that -- that's perfectly fine.

The downside is saying that we want to - - the alternative, I guess, is to say, No, no, let's work up rates now, let's -- let's head for our retained earnings not at 2 1/2 billion, not at 3 1/2 billion, but, you know, you look in the latter years of the IFF, and it's 5 billion or 6 billion.

And -- and the question has to be, what are -- what are -- what are ratepayers getting for that? Why are they -- why would it make sense for them to be wanting to have that much out of -- of the overall economy, that much out of investment, that much out of investment, that much park -- parked in Manitoba Hydro if it's -- if it's not serving a purpose of helping stabilize rates?

It -- it -- the only other purpose it possibly serves is offsetting a little bit of interest costs. But I think it's -- it probably is far from the

most-efficient way to have Manitobans save is through their -- their retained earnings investment in Manitoba Hydro compared to the alternative uses of that.

MR. RAYMOND LAFOND: And that will be my final comment on interest rates, but it seems to me that if current ratepayers benefit from short-term rates of 15 to 30 percent based on Hydro's policy, the current ratepayer should also pay some of the risk for financing long-term projects with short-term rates instead of very long-term rates, because these are projects -- capital projects that have a hundred life expec -- a hundred-year life expectancy.

That's all I'm -- I was getting at, because if we get the benefit now for low, short term rates, we should probably also put a reserve for the risk of -- of having these low rates versus fixed rates; in other words, benefiting for -- from -- for a 3 or 4 percent rate right now versus paying 6 percent, which is technically the proper type of debt we should have on long-term projects. That was my point.

MR. PATRICK BOWMAN: Yeah, and I think it's a -- it's a very good point. And I -- I accept the premise entirely that if, for some reason, we were to sit here and say, Wow, we're going to -- we're going to take a bunch of short-term debt, beyond what a good

portfolio analysis would show, because -- because the rates are really low.

So let's make sure we nab a bit of that short-term debt a bit more than we could otherwise justify and -- and really pass through some cost savings on to ratepayers, or -- or some benefits into Hydro's system. And -- and we know we're doing it on borrowed time, but -- but let's grab it. Let's do it. That would be a bad -- a -- a --

MR. RAYMOND LAFOND: Yeah, I -- I understand the principle. I'm just wanting to relate it directly to the current policy of 15/30 percent. Like, a bunch of money doesn't tell me anything. I mean, like, it's just the -- the problem between 15 and 30 percent.

Is that something you agree with or -- or you don't? Or are you...?

MR. PATRICK BOWMAN: I -- I would -- I don't spend a lot of my time working in debt portfolios, but in my experience working with -- with utilities that have long-lived assets or financing large projects, the tendency would be to keep very low levels of -- of debts in -- in -- on short-term rates.

Now, fifteen (15) is -- is pretty low. It's not very low. Thirty (30) is -- seems very high,

to me. But I can also understand how somebody who is actually far more versed in a portfolio analysis could come in and make an argument and says, No, no, you're all missing the point; in fact, 30 percent is not only cheaper than the other, but it's also less risky than the other. And they could put together an assessment, and -- and I think we could all look at it.

But -- but thirty (30) is a big number. Thirty (30) is a really big number for that. I -- I'm not -- I have not experienced and I cannot recall an example of where I would have seen a utility dealing with assets like this that would have variable rates up in the 30 percent range. It would be much, much lower and -- and locked in as early as possible.

MR. RAYMOND LAFOND: So I can conclude that Manitoba Hydro following the lower end of the scale of their 15 to 30 percent policy is not an issue for MIPUG?

MR. PATRICK BOWMAN: We -- we've never -- I -- I have never and -- and MIPUG has never argued that they would have any concern with a 15 percent level if it can be justified on the basis of, you know, a good portfolio analysis. I -- I would be sceptical of seeing a -- a -- something that says that -- that 30 percent makes sense, especially -- especially at a current time when you know you're going to be adding a bunch of debt.

In essence, if you're -- if you really are building the plant, if you're really going forward, then... How do I put it? Even though you may not have it financially on your books right now, the debt associated with that, you're starting to rack up the commitments associated with a debt like that. And you have created an interest rate risk and an exposure to variations in interest rates that aren't for the debt you're borrowing; it's for the debt you're about to borrow.

And that would probably be in a proper portfolio analysis, looking over a -- a five (5) to ten (10) year period, a good reason to say, I'm not going to be fifteen (15) to thirty (30); I might be way below that, because -- because I also have to consider this exposure, right.

THE CHAIRPERSON: But I do -- I do want to -- your -- your central thesis, I think, is the fact that Manitoba Hydro is intending to -- to increase its -- its reserves in anticipation of future events. Am - - am I correct in that?

I mean, that's your central argument, isn't it?

MR. PATRICK BOWMAN: Well, the argument is less before the Board in this hearing than it was in -- in the last one. But the argument that I've made is Manitoba Hydro's requires reserves. Call them retained earnings if you want, although as a concept, accounting retained earnings are -- isn't -- isn't perfect as a concept for reserves.

But -- but they required reserves. Those reserves benefit ratepayers. We ought put reserves aside, and we ought assess the need for more or less reserves in the context of how it benefits ratepayers. And benefit is tied to stability of rates. Okay?

I can accept the rationale that has led to the 2 1/2 billion that is there now. I can accept a rationale that says, You may have to reassess those levels as you move forward and add plant.

But I think the 25 percent ratio or the -- or the -- the $6 billion level that's shown in the - - in the IFF, when you get out to the latter years, there's reason to be sceptical that that's actually an amount of reserves that ratepayers will really -- that really will make sense for them to -- to help put aside to their own benefit. And -- and I don't know if it's not to ratepayer benefit, I don't know what other

rationale we have for -- for putting those reserves aside.

THE CHAIRPERSON: At the moment, if we -- if the panel supports the Application that's been made by Manitoba Hydro, they're looking at net income for the two (2) test years of roughly 50, $60 million a year for a corporation that has revenues in the order of over a billion dollars a year.

And that, to me, does not seem to be an attempt to increase reserves, given the size of -- given the size of the Corporation's revenues and given the many moving parts that are -- that impact on Manitoba Hydro's revenues. It doesn't seem to me that that's an attempt to increase their reserves beyond a reasonable level.

But I'd like to hear your point of view on that.

MR. PATRICK BOWMAN: You -- you and I completely agree on that point, Mr. Chairman, and -- and it's one (1) of the reasons why I've said in PUB -- well, the question in PUB-11, I've -- I've put -- put some numbers that we'll -- I think we'll get to. But I've said I'm not taking issue with -- with the reserve levels that are there. But I think if the argument -- I think the argument this Board has to be a bit careful

of is Hydro saying, Things are really bad, because we were targeting to be putting aside 160 or 180 or 200 million a year, and now we're only putting aside 60 a year.

And I think this Board has to assess and say, Is -- is 60 so bad, given what we're facing today? We may have been talking that level. And -- and maybe that was justified and maybe it wasn't. But how does 60 -- putting aside 60 today -- with some variability, but how does putting aside 60 today compare the situation we face today?

And -- and we're going to touch on this in a minute. But it's -- I would su -- submit it's not that bad. It's -- it's building on -- at a mean level. It's continuing to build over a period of -- of an IFF, where lots of other costs are going on, lots of other cost increases and pressures. And -- and it's led to retained earnings that are booked, which, as I said, I -- you have to be a bit careful about what we're focussing on that number. But it's led to retained earnings that are booked that are -- are higher than they've ever been in Hydro's history and that, in relation to many of the risks Hydro faces, are -- are higher as a percentage than -- than they were even two (2) years ago when we sat here.

TAB 7

MOODY'S
INVESTORS SERVICE

RATING METHODOLOGY

US Public Power Electric Utilities With Generation Ownership Exposure

This rating methodology replaces "US Public Power Electric Utilities With Generation Ownership Exposure", last revised on March 1, 2016. We have updated some outdated links and removed certain issuer-specific information.

Table of Contents:

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Summary

This rating methodology explains our approach to assessing credit risk for US Public Power Electric Utilities with Generation Ownership Exposure. This document provides general guidance that helps issuers, investors, and other interested market participants understand how qualitative and quantitative risk characteristics are likely to affect rating outcomes for US public power electric utilities whose credit profile is largely influenced by power generation ownership. This document does not include an exhaustive treatment of all factors that are reflected in our ratings but should enable the reader to understand the qualitative considerations and financial information and ratios that are usually most important for ratings in this sector.

This report includes a detailed scorecard. The scorecard is a reference tool that can be used to approximate credit profiles within the US public power electric utilities with generation ownership exposure sector in most cases. The scorecard provides summarized guidance for the factors that are generally most important in assigning ratings to issuers in the US public power electric utility sector whose credit profile is largely influenced by power generation ownership. However, the scorecard is a summary that does not include every rating consideration. The weights shown for each factor in the scorecard represent an approximation of their importance for rating decisions but actual importance may vary substantially. The scorecard-indicated rating is not expected to match the actual rating of each issuer.

The scorecard contains five factors that are important in our assessment for ratings in the US public power electric utilities with generation ownership exposure sector:

1. Cost Recovery Framework Within Service Territory
2. Willingness and Ability to Recover Costs with Sound Financial Metrics
3. Generation and Power Procurement Risk Exposure
4. Competitiveness
5. Financial Strength and Liquidity

The scoring for factors 1-5 is aggregated to produce a preliminary scorecard-indicated rating that is adjusted upwards or downwards based on our view of scoring for factors 6, 7 and 8. Scoring for factors 6-8 can result in upward or downward notching for issuers that exhibit better or worse than typical positions in these areas.

6. Operational Considerations
7. Debt Structure and Reserves
8. Revenue Stability and Diversity

The combination of factors 1-8 results in the scorecard-indicated rating. An issuer's scoring on a particular scorecard factor or sub-factor often will not match its overall rating.

This rating methodology is not intended to be an exhaustive discussion of all factors that our analysts consider in assigning ratings in this sector. We note that our analysis for ratings in this sector covers factors that are common across all industries such as ownership, management, liquidity, legal structure, governance and country related risks, which are not explained in detail in this document, as well as factors that can be meaningful on an issuer-specific basis. Our ratings consider these and other qualitative considerations that do not lend themselves to a transparent presentation in a scorecard format. The scorecard used for this methodology reflects a decision to favor a relatively simple and transparent presentation rather than a more complex scorecard that would map scorecard-indicated ratings more closely to actual ratings.

Highlights of this report include:

» An overview of the rated universe
» A summary of the rating methodology
» A description of factors that drive rating quality
» Comments on the rating methodology assumptions and limitations, including a discussion of rating considerations that are not included in the scorecard

The Appendix provides the full scorecard.

Due to the prevalence in this sector of financing secured by a senior net revenue pledge (senior revenue bonds), the scorecard in this methodology is calibrated for this rating class, and the rating utilized for comparison to the scorecard-indicated rating is the issuer's senior revenue bond rating. Ratings for individual debt instruments also factor in assessments reflected in notching for seniority level and collateral. The document that provides broad guidance for such notching decisions is our methodology for aligning corporate instrument ratings based on differences in security and priority of claim.[1] All issuers in this sector are owned by government entities in the US, and the scorecard is calibrated to incorporate the benefits of government ownership. As a result, uplift under our rating methodology for Government-Related Issuers does not apply to this sector.[2]

This methodology describes the analytical framework used in determining credit ratings. In some instances, our analysis is also guided by additional publications which describe our approach for analytical considerations that are not specific to any single sector. Examples of such considerations include but are not limited to: the assignment of short-term ratings, the relative ranking of different classes of debt and hybrid

1 Access our methodology for notching corporate instrument ratings based on differences in security and priority of claim by using the link in the Related Research section of this report.

2 Our methodology for rating Government-Related Issuers (GRIs) can be accessed using the link in the Related Research section of this report.

securities, how sovereign credit quality affects non-sovereign issuers, and the assessment of credit support from other entities.[3]

About the Rated Universe

This methodology is applicable to US public power utilities that own significant generation assets or that obtain at least 20% of their capacity/energy from directly owned power generation assets and/or from participation in municipal joint action agencies (JAAs). The issuers rated under this methodology include autonomous US federal, state and local power authorities, and departments of a municipality. The bonds issued by all of these entities are serviced solely from their utility and related operations; they do not represent general obligations of the governments that own or control them. Some of the utilities rated under this methodology are integrated, combining generation with high voltage transmission and lower-voltage distribution systems to sell power directly to end-users. Some issuers rated hereunder do not have distribution systems – they sell the power they generate and/or procure on a wholesale basis to other utilities.

Further characteristics that typify US public power utilities with generation exposure include:

» Near monopoly position in providing an essential service

» Unregulated and independent local rate-setting authority[4]

» Cost structure that is generally lower than investor-owned utilities due to the ability to issue lower cost tax-exempt debt and, for some, the availability under federal statute of federal low cost preference power

» Although not typically subject to income taxes or property taxes, most make payments in lieu of taxes (PILOTs); some also may make payments referred to as General Fund Transfers (GFTs)

» Lack of profit motive or need to generate a return on equity

US public power utilities with generation exposure under the 20% threshold on a sustained basis and those that have only transmission and distribution operations are rated under our US Municipal Utility Revenue Debt methodology.[5] Municipal joint action agencies are entities formed by a group of US municipal utilities (participants) to provide reliable and competitively priced energy or energy related services – typically power, though they may also provide natural gas, electric transmission, or telecommunications services for energy assets. The participating municipal utility systems share an obligation established through a long-term contractual arrangement to cover the JAA's operating, capital, and debt service costs. JAAs are rated under our US Municipal Joint Action Agencies methodology.[6]

Public power electric utilities that either own significant generation assets or obtain at least 20% of their electricity from directly owned power generation assets and/or from JAA participation generally have more fundamental credit risks than other essential purpose enterprises such as public power electric utilities that do not own generation assets. These fundamental risks include exposure to commodity markets, environmental regulation and larger capital requirements to maintain, refurbish or replace generation assets.

The history of US public power utilities with generation exposure generally reflects the essentiality of their service, monopoly positions, and, in most cases, autonomous rate-setting ability. However, US public

[3] The methodologies covering our approach to these cross-sector considerations can be found in the Related Research section of this report.

[4] Certain exceptions may apply.

[5] Our methodology for rating US municipal utility revenue bonds can be accessed using the link in the related research section of this report.

[6] Access our methodology for rating revenue bonds of US municipal Joint Action Agencies (JAA) by using the link in the related research section of this report.

power electric utilities that own generation typically have a higher degree of business complexity and credit risk than other essential municipal services such as electric and gas distribution, water, sewer, and storm water systems. Specifically, generation-owning electric utilities typically have greater operating and capital deployment risks, because they have a more complex asset conversion cycle and are subject to ongoing changes in regulations and commodity price that can affect the relative cost-efficiency of their generating fleets. While there remain many similarities with other essential purpose revenue bonds such as governance, bondholder security provisions and rate-setting flexibility, the challenging operating environment for a generation-owning electric utility is more pronounced. While there are some nuanced differences between direct ownership and JAA participation, in broad terms, a public power electric utility shares in the risks associated with JAA generation, and the scorecard factors are generally the same for these two sub-groups.

JAA participation typically takes one of two forms - a take-or-pay contract or an all requirements take-and-pay contract. Under a typical take-or-pay contract for a particular power plant, the utility is required to pay its share (usually a fixed percentage) of the JAA's total life-cycle costs of owning and operating that plant, even if the plant is not operable and regardless of whether the utility takes the power the plant generates. Termination provisions under take-or-pay contracts are essentially non-existent. Under a typical all requirements take-and-pay contract, the utility agrees to purchase all of its power needs (or a portion thereof) from the JAA and is responsible for a percentage of the JAA's total costs while the contract is in effect. The utility typically has the right to terminate the all requirements take-and-pay contract after a multi-year notice period, and the utility's obligation with respect to the JAA's costs is based on the utility's percentage share of the total power taken by all participants, which can vary over time according to usage patterns or the entry/exit of JAA participants.

Broad industry changes continue to introduce uncertainty to the public power sector, such as deregulation initiatives that have introduced a degree of competition, ongoing environmental policy changes, and supply and demand factors. Electric generation is capital intensive, and US public power electric utilities with generation exposure must make decisions that result in long-term obligations amidst a changing operating environment. There have been no bond defaults and no bankruptcies in the past 50 years among US public power utilities with generation exposure, reflecting the sector's fundamental strengths.

About this Rating Methodology

This report explains the rating methodology for US public power electric utilities with generation ownership exposure in several sections, which are summarized as follows:

1. Identification and Discussion of the Scorecard Factors

The scorecard in this rating methodology focuses on eight rating factors. One of these factors is comprised of sub-factors that provide further detail. Factors 6-8 are used to make notching adjustments for operational considerations, debt structure and reserves, and revenue stability and diversity.

EXHIBIT 1

US Public Power Electric Utilities with Generation Ownership Exposure Methodology Factor Scorecard

Scorecard Factors	Factor Weighting	Sub-Factors	Sub-Factor Weighting
Cost Recovery Framework Within Service Territory	25%		25%
Willingness and Ability to Recover Costs with Sound Financial Metrics	25%		25%
Generation and Power Procurement Risk Exposure	10%		10%
Competitiveness	10%		10%
Financial Strength and Liquidity	30%	Adjusted days liquidity on hand (3-year avg) (days)	10%
		Debt ratio (3-year avg) (%)	10%
		Adjusted Debt Service Coverage OR Fixed Obligation Charge Coverage (3-years avg) (x)	10%
Total	**100%**	**Total**	**100%**
Operational Considerations	(notching adjustment)		
Debt Structure and Reserves	(notching adjustment)		
Revenue Stability and Diversity	(notching adjustment)		

2. Measurement or Estimation of Factors in the Scorecard

We explain our general approach for scoring each scorecard factor or sub-factor and show the weights used in the scorecard. We also provide a rationale for why each of these scorecard components is meaningful as a credit indicator. The information used in assessing the factors and sub-factors is generally found in or calculated from information in utility financial statements, derived from other observations or estimated by our analysts.

Our ratings are forward-looking and reflect our expectations for future financial and operating performance. However, historical results are helpful in understanding patterns and trends of an issuer's performance as well as for peer comparisons. We utilize historical data (in most cases, an average of the last three years of reported results) to illustrate the application of the scorecard. However, the factors and sub-factors in the scorecard can be assessed using various time periods. For example, rating committees may find it analytically useful to examine both historic and expected future performance for periods of one year, several years or more.

The quantitative credit metrics in the scorecard incorporate any Moody's adjustments to the income statement, cash flow statement and balance sheet amounts.

3. Mapping Scorecard Factors to the Rating Categories

After estimating or calculating each factor or sub-factor, the outcomes for each of the factors and sub-factors are mapped to a broad Moody's rating category (Aaa, Aa, A, Baa, Ba, or B).

4. Assumptions, Limitations and Rating Considerations Not Included in the Scorecard

This section discusses limitations in the use of the scorecard to map against actual ratings, some of the additional factors that are not included in the scorecard but can be important in determining ratings, and limitations and assumptions that pertain to the overall rating methodology.

5. Determining the Overall Scorecard-Indicated Rating

To determine the preliminary scorecard-indicated rating before notching considerations, we convert each of the factor and sub-factor scores into a numerical value based upon the scale below.

Sub-factor score to numeric value

Aaa	Aa	A	Baa	Ba	B
1	3	6	9	12	15

The numerical score for each scorecard factor or sub-factor is multiplied by the weight for that factor with the results then summed to produce a composite weighted-factor score. The composite weighted factor score is then mapped back to an alphanumeric rating based on the ranges in the table below.

Scorecard-Indicated Rating	Aggregate Weighted Total Factor Score
Aaa	x < 1.5
Aa1	1.5 ≤ x < 2.5
Aa2	2.5 ≤ x < 3.5
Aa3	3.5 ≤ x < 4.5
A1	4.5 ≤ x < 5.5
A2	5.5 ≤ x < 6.5
A3	6.5 ≤ x < 7.5
Baa1	7.5 ≤ x < 8.5
Baa2	8.5 ≤ x < 9.5
Baa3	9.5 ≤ x < 10.5
Ba1	10.5 ≤ x < 11.5
Ba2	11.5 ≤ x < 12.5
Ba3	12.5 ≤ x < 13.5
B1	13.5 ≤ x < 14.5
B2	14.5 ≤ x < 15.5
B3	15.5 ≤ x < 16.5
Caa1	16.5 ≤ x < 17.5
Caa2	17.5 ≤ x < 18.5
Caa3	18.5 ≤ x < 19.5
Ca	x ≥ 19.5

For example, an issuer with a composite weighted factor score of 11.7 would have a Ba2 preliminary scorecard-indicated rating

Finally, we consider whether the preliminary scorecard-indicated rating score that results from factors 1-5 should be notched upward or downward based on operational considerations, debt structure and reserves, and revenue stability and diversity, in order to arrive at a final scorecard-indicated rating.

6. Appendix

The Appendix provides the full scorecard.

Factor 1: Cost Recovery Framework Within Service Territory (25% Weight)

Why It Matters

The ability to recover prudently-incurred costs in a timely manner is one of the most important credit considerations for US public power electric utilities with generation ownership exposure, as a delay in cost recovery may cause financial stress. Therefore, the monopoly status, rate autonomy and where applicable, predictability and supportiveness of the regulatory framework in which a public power utility operates – as well as the legal and political framework that underpins it - are key credit considerations that differentiate this sector from most corporate sectors. In addition, the strength and diversity of the service territory is important because it can indirectly influence a public power electric utility's cost recovery framework. Larger, more diverse service areas with greater economic wealth are better able than smaller, less diverse areas to support rate increases that may be required as a result of changes in fuel and operating costs, required capital expenditures, or other causes.

In general, the US public power electric utilities with generation ownership exposure rated under this methodology are effectively monopoly providers of essential electric services, which limits competitive threats. With few exceptions, they are not subject to rate regulation, i.e. their revenues are not subject to price controls under the jurisdiction of any state public utility service commission as part of the process to reset them periodically. Price-setting mechanisms are generally structured by management, governing boards and or city councils at their sole discretion to limit volatility wherever possible and therefore tend to be highly predictable. The benefits of monopoly status and rate autonomy are further bolstered for most public utilities by minimum bond security covenants that require current revenues to match current expenses, including payment of debt service. There are some instances where regulation of rates by state public utility service commissions does apply. In these instances, the regulators may also have an effect on capital spending decisions and efficiency targets to reduce operating costs, which can affect the public utility's business position.

How We Assess the Cost Recovery Framework Within Service Territory for the Scorecard

Collectively three components, [1] the strength of monopoly control over a service area, [2] unregulated rate raising ability, and [3] the strength of a public power utility's customer base and service area economy are core characteristics in assessing this factor. In the US, public power electric utilities have maintained a near monopoly role in their service area, limiting competitive threats to their customer base. This monopoly control, in combination with an unregulated rate setting process, provides a greater certainty of the utility's ability to access its revenue requirement from the region served. Among utilities with strong monopolies and autonomous rate-setting, assessment of the customer base and service area economic strength provides differentiation for this factor.

When evaluating the credit characteristics of the utility's service area, we consider population, employment trends, wealth indicators, and local economic diversity and growth projections. For example, we often utilize Moody's Economy.com for an assessment of current and projected economic strength of a particular service area. Weak economic characteristics and limited economic diversity would contribute to a lower score for Factor 1.

We also evaluate the wealth indicators of the population that a utility serves to gauge the ability of customers to pay their electric bills, both currently and in the future, if rates rise. Affluent residential customers generally have a higher tolerance for higher overall rates, since the electric bill is a small part of their disposable income.

We look at the relative mix of residential, commercial and industrial customers when assessing the stability of the customer base. Factor scoring for US public power electric utilities that serve a primarily residential customer base (e.g., more than 50% residential sales) would generally be favorably influenced because of benefits from the more stable load and revenue trends that typify the customer class. Alternatively, a customer base dominated by industrial load, particularly if concentrated in one or just a few industrial customers, would exert negative influence on scoring because public utilities with such a characteristic are more susceptible to economic cycles and demand changes that could affect revenue stability.

US public power electric utilities with generation ownership exposure that are subject to rate regulation typically receive lower scores for Factor 1, because rate regulation can sometimes limit or delay cost recovery. Public power electric utilities predominantly have amortizing debt and a debt service coverage requirement, so regulatory lag or cost disallowance that creates uncertainty could increase default risk. For utilities with regulated rate-setting, the regulatory framework can vary by state and may provide greater or lesser predictability in the certainty and timing of cost recovery depending on its details and the manner in which it is applied by regulators. Some states like Wisconsin and Indiana regulate public power electric utilities, but the regulation tends to be credit supportive, and regulators are required to consider bond covenants in their rulemaking. As reflected in the scorecard, regardless of other considerations in this factor, including service area economic strength and customer concentration, if a public power electric utility falls under typical state regulation (as normally applied to investor owned utilities) our assessment of Factor 1 would typically not exceed a Baa score.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Cost Recovery Framework Within Service Territory	25%	Monopoly with unregulated rate setting and very strong customer base and service area economy	Monopoly with unregulated rate setting and strong customer base and service area credit economy	Monopoly with unregulated rate setting; average customer base and service area economy	Regulation of rates by state; weak customer base / service area economy	Regulation of rates by state with some inconsistency; or very weak customer base or service area economy	Regulation of rates by state is unpredictable; or extremely weak customer base or service area economy

Factor 2: Willingness and Ability to Recover Costs with Sound Financial Metrics (25% Weight)

Why It Matters

Willingness to use the independent and local rate-setting authority guided by sound bond covenants and governance is an extremely important consideration and a heavily weighted rating factor. Unregulated public power utilities may have the ability to raise rates but there can be meaningful differences in their willingness to do so, for a variety of public policy reasons that may have the effect of placing rate-payer concerns ahead of sound financial policy. Regulated public power utilities must have both the willingness to seek rate increases and the ability to obtain the necessary regulatory approvals. In either case, implementing rate increases in a timely fashion in order to maintain sound financial credit strength has been a fundamental credit strength for most issuers in the sector. Credit risk increases in the absence of the stability and certainty that maintenance of a financial buffer provides in mitigating the impact of modest credit stress events. Political risk or (when applicable) lack of regulatory support can result in an unwillingness or inability to establish sufficient rates to maintain sound financial metrics. Without sound rate-setting that is predictable and timely, debt service coverage ratios or liquidity are likely to be compromised. This factor may be a leading indicator of the direction of future financial performance for a US public power electric utility with generation ownership exposure.

Another important aspect is the degree of support, or lack thereof, from a related governmental entity, since most public power electric utilities are owned by local governments. This matters because a city may use its broader governance authority and or financial resources to prevent financial deterioration of the utility, which serves to protect revenue bond holders. Conversely, the government owner can take distributions from the utility, typically in the form of General Fund Transfer (GFTs), that limit the latter's financial flexibility, and the government can pressure the utility to hold down rates or increase capital expenditures in a manner that is detrimental to the maintenance of sound financial metrics.

The ability to automatically adjust rates for changes in fuel or power purchase costs has become a more notable credit factor in the past decade given wide fluctuations in natural gas prices, ongoing hydrology risk, and the volatility of the wholesale power market. Some utilities source a portion of their energy needs in the wholesale market, while others have used profits from wholesale sales to reduce the revenue requirement from retail users.

Rate-setting is a dynamic process that will continue to be tested in the next several years as power supply costs rise due to increased environmental regulation, demand growth remains slow due to the slow economic recovery, and utilities shift to cleaner but sometimes more expensive sources of supply (i.e., to comply with renewable portfolio standards). A forward view of a utility's ability and willingness to set rates to recover all costs has high importance.

How We Assess Willingness and Ability to Recover Costs with Sound Financial Metrics for the Scorecard

In assessing this factor, we evaluate the governing board's rate-setting process for its transparency, timeliness and supportiveness in setting the rates and charges necessary to ensure that costs, including debt service, are fully recovered. This may include considerations regarding the utility's ability to generate targeted revenue based on underlying volume assumptions. Rate mechanisms that mitigate the impact of revenue volatility are viewed positively.

Another key part of our assessment for this factor is length of time it takes to implement new rates and collect the additional revenues. A demonstrated record of ability and willingness to change rates on a timely or pro-active basis as required to recover operating and capital costs, to provide a cushion for debt service coverage, and to maintain sound liquidity are credit positives and would likely lead to scores at the mid-to-higher end of the rating scale for this factor, when that record is expected to continue. In those cases where utilities waiver and delay on actions to adjust rates as necessary to provide timely assurance of cost recovery, we would likely score them lower for this factor than we would for those who are more proactive in adjusting their rates.

Utilities that have an automatic fuel and purchased power cost adjustment mechanism are able to recover these costs on a more timely basis. Such adjustment mechanisms would typically contribute to a higher score for this factor because the mechanisms serve to narrow the potential drain on liquidity and the resulting impact on credit quality and are of particular importance should there be a fuel price spike or a forced outage of a generating unit. A material lag before the utility can recover these costs would likely contribute to a lower score.

When assessing this factor we also consider the relationship of the local government with the electric utility. This will not always be a material consideration, as some utilities have no fiscal relationship with a local government, or the utility may have been established as a separate and independent authority. We consider who governs the utility, who sets its rates, and who issues the revenue bonds for the utility, as well as the degree to which the general government is responsible for supporting the utility in times of financial stress. Higher scores for this factor would be likely under circumstances where the interests of the utility and the government are aligned, and where a highly-rated local government has a strong record of supporting their public power electric utility in times of fiscal stress. Political risks and/or regulatory barriers that impede a utility's willingness to enact rates and charges on a timely basis that are sufficient to maintain the associated financial metrics for a utility's rating category would likely result in a lower score for this factor.

Finally, we focus on GFT policies when assessing this factor because the policies are an example of the relationship between a utility and their local government. The GFT is the transfer of surplus utility revenues from the utility to the city's General Fund. Policy-driven GFTs in very limited or conservative amounts typically contribute to higher scores for this factor, while ad hoc, larger amounts of GFTs not governed by policy typically contribute to a lower score. Established, prudent GFT policies that are accepted by both the utility and the local government add credit strength because they increase the predictability of the amount to be transferred. Alternatively, a policy established after a contentious debate for a transfer amount that represents a substantial portion of the utility's own revenues could have a negative impact, (i.e. if it produces uncompetitive electric rates or leaves limited internal funds available for utility operations, maintenance, and repairs) and contribute to a lower score for this factor.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Willingness and Ability to Recover Costs with Sound Financial Metrics	25%	Excellent rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments less than 10 days; No political intervention in past or extremely high support from related government; Very limited General Fund transfers governed by policy	Strong rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments 10 to 30 days; Limited political intervention in past or high support from related government; Conservative and well-defined General Fund transfers governed by policy	Adequate rate-setting record expected to continue; Rates, fuel, & purchased power cost adjustments 31 to 60 days; Some political intervention in past or average support from related government; Moderate General Fund transfers	Below average rate-setting record; Rates, fuel, & purchased power cost adjustments 61 to 99 days; Persistent political intervention or below average support from related government; Large General Fund transfer not governed by policy	Some history or expectation of insufficient rate-setting; Rates, fuel, & purchased power cost adjustments 100 to 120 days; Highly political climate or very limited support from related government; Sizeable General Fund transfer not governed by policy	Lengthy record of, or expectation for a prolonged period of insufficient rate-setting ; Rates, fuel, & purchased power cost adjustments 120 days or more; Highly contentious political climate or clear lack of support from related government; Very sizeable General Fund transfer not governed by policy

Factor 3: Generation and Power Procurement Risk Exposure (10% Weight)

Why It Matters

Generation and power procurement risks, power supply costs and system reliability have an important influence on a utility's ability to meet its service obligations, the competiveness of current and future rates, and financial metrics over time. Efficiently meeting its current electricity demand and planning effectively for future demand has direct bearing on a utility's leverage, customer satisfaction, rate levels, service reliability, and often on the political support for the utility. Political and regulatory support rooted in customer satisfaction can translate into a greater willingness and ability to establish the rate levels needed to keep the utility in sound financial condition.

Successful resource planning, most often accomplished through fuel source diversity and the maintenance of a sufficient but not excessive reserve margin, is fundamental to the utility's future health given the objective to provide low-cost, safe and reliable power supply to its customers. The continuing challenge of managing environmental regulations related to clean air and renewable standards underscores the importance of this factor. These standards, which can vary by state, have been increasing over time and are often litigated. This typically delays implementation, and may cloud the visibility into the standards that will eventually be enforced.

How We Assess Generation and Power Procurement Risk Exposure for the Scorecard

When assessing generation and power procurement risks, we consider the mix and diversity of a utility's power supply, as well as the cost and reliability. Maintaining a diverse fuel and resource mix increases the utility's flexibility to manage peak demand while limiting the utility's exposure to volatile commodity and energy market prices, disruptions in the delivery of a single fuel source, or increased costs associated with a particular asset, for instance the cost of environmental compliance for a coal plant. Our review of the utility's generation performance record may include indicators such as availability (% of time a generation unit is operational); capacity factor (% of capacity the generation fleet runs); and heat rates (efficiency of a generator to convert fuel into electrical energy). Additional considerations may include the primary terms and conditions of any purchase power agreements in the context of the utility's overall power supply mix, the positioning of the assets on the regional dispatch curve and the associated impact on the all-in cost of power supply, and the main drivers of the overall retail price charged to the end-use customer. Above-market power supply costs could lead to higher retail charges to end-use customers, which would likely contribute to a lower score for this factor.

We consider the utility's main generation sources, whether owned or purchased under contract, since each type (e.g. natural gas, coal, nuclear, hydro) has risks which must be properly managed. Such risks include fuel price (for instance, natural gas prices can demonstrate high seasonal volatility), transportation issues (e.g., availability of rail and barging delivery for coal, availability of peak period pipeline capacity for natural gas), safety regulations (e.g., Nuclear Regulatory Commission (NRC) regulations for nuclear generation facilities), hydrology risks for hydroelectric generating units, and environmental compliance issues for coal-fired generating units.

In evaluating the generation strategy, we consider the utility's flexibility with regard to fuel-switching. Alternate transportation modes/routes and fuel storage may also be meaningful considerations. By maintaining sufficient power resource reserve margin, a utility is better positioned to manage an unexpected forced outage of a large generating facility. Risk exposures that are not adequately mitigated would contribute to a lower score on this factor.

Public power electric utilities with limited diversification or that are heavily reliant on a single type of generation and fuel source typically score lower on this factor. In some cases, such as high reliance on hydro, the risk may be mitigated somewhat by the cost competitiveness of the fuel source, provided there is ready access to alternative sources of generation. Utilities with a high reliance on coal-fired generation are likely to score lower on this factor due to their vulnerability to future EPA regulations, including under the Clean Power Plan.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Generation and Power Procurement Risk Exposure[7]	10%	Very limited exposure to negative repercussions from generation, procurement and commodity price risks; High degree of diversification of generation and/or fuel sources; Single generation asset typically provides less than 20% of power; or up to 20% of energy from coal-fired generation with carbon mitigation strategy	Limited exposure to negative repercussions from generation, procurement and commodity price risks; Some diversification of generation and/or fuel sources; Single generation asset typically provides less than 40% of power; or up to 40% of energy from coal-fired generation with carbon mitigation strategy	Moderate exposure to negative repercussion from generation, procurement and commodity price risks; Some reliance in one type of generation and/or fuel source, but diversified with purchased power sources; Single generation asset may provide up to 55% of power; or up to 55% of energy from coal-fired generation with carbon mitigation strategy	Moderate to high exposure to negative repercussion from generation, procurement and commodity price risks; Reliance on a single type of generation or fuel source, with somewhat limited diversification via purchased power; Single generation asset typically provides up to 75% of power; or up to 70% of energy from coal-fired generation with carbon mitigation strategy	High exposure to negative repercussion from generation, procurement and commodity price risks; Very high concentration in a single type of generation or very high reliance on a single fuel source, with limited diversification via purchased power; Single generation asset typically provides up to 75% of energy from coal-fired generation with carbon mitigation strategy, or up to 50% of energy from coal with no mitigation strategy	Very high exposure to negative repercussion from generation, procurement and commodity price risks; very high concentration in a single type of generation, almost entirely reliant on a single fuel source, with very limited diversification via purchased power; Single generation asset typically provides over 85% of power; or over 85% of energy from coal-fired generation with carbon mitigation strategy, or over 50% of energy from coal-fired generation with no mitigation strategy

Factor 4: Competitiveness (10% Weight)

Why It Matters

Despite the closed retail market for almost all public power electric utilities, an important advantage of the sector is the price competitiveness for retail and/or wholesale customers, especially relative to investor-owned utilities. We would expect increased political and regulatory risks if the utility has uncompetitive rates, leading to a potentially more challenging rate setting environment despite the rate autonomy that is prevalent in the sector. High retail rates cause pressure on the governing board (and regulators when applicable) to delay rate increases or perhaps even lower rates, which could affect the utility's ability to recover costs and weaken debt service coverage. In addition, high rates may discourage economic development and contribute to a stagnant or declining revenue base, which could impact debt service coverage in the long-run. Public power electric utilities with large, energy-intensive customers that contribute significantly to their net income could face pressure if high industrial or commercial retail rates motivate those large customers to relocate. The shuttering/relocation of large users can weigh negatively on the local economy and also place additional upward pressure on electric rates for the utility's remaining customers.

How We Assess Competitiveness for the Scorecard

In assessing this factor, we consider a utility's average system retail rate in the context of its regional peers. In many cases, the state average rate is very relevant, but a competiveness comparison to neighboring utilities may be more important for some issuers. For instance, in some states a single utility may dominate, rendering in-state comparisons less meaningful. For public utilities near major metropolitan areas, the

7 In scoring this factor, generation includes generation from owned assets and via participation in JAAs, unit power agreements and similar arrangements.

important comparison may be to neighboring utilities, especially if there are transmission constraints to in-state utilities that may have a different cost base.

A comparison of retail rates is generally considered in terms of the system average revenue per kilowatt hour (cents/kwh). The average system rate is a useful benchmark that can allow comparisons among regional markets, but it does not distinguish between different customer classes and rate designs. For instance, for some utilities with heavy industrial loads, competitiveness of the industrial rate may be more important than the system average rate, especially if industry is a major driver of employment. For utilities in a contentious political/regulatory environment, residential rates may be most important. For utilities with meaningful wholesale generation, we typically also compare wholesale rates against regional benchmarks to assess the competitive position of that portion of the utility's business, which can be a meaningful consideration, because in most cases the wholesale business is less stable than regulated retail supply.

Our view in this factor is forward-looking, and when relevant we consider future capital spending plans and other cost pressures, such as those for environmental compliance, to assess the likelihood they will create a need for rate increases that pressure the utility's competitive standing.

Generally, those utilities with a stronger competitive starting point compared to the relevant benchmark and that are not facing material cost pressures have more flexibility to withstand competitive challenges and score toward the higher end of the scorecard for this factor. Competitively challenged utilities, whether on a current basis or prospectively would typically score in the mid-to-lower portion of the scorecard for this factor.

Factor	Weight	Aaa	Aa	A	Baa	Ba	B
Competitiveness	10%	Extremely competitive current and expected rates[8] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates more than 25% below state average); and virtually no material prospective cost pressures that could lead to higher rates	Very competitive current and expected rates[8] in the state and/or compared to neighboring utilities on a consistent basis (e.g. average system rates in a range of 7.5% to 25% below state average); very low likelihood of material prospective cost pressures that could lead to higher rates	Competitive current and expected rates[8] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 7.5% below state average to 7.5% above state average); modest likelihood of material prospective cost pressures that could lead to higher rates	Somewhat competitive current and expected rates[8] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 7.5% to 25% above state average); high likelihood of material prospective cost pressures that could lead to higher rates	Uncompetitive current or expected rates[8] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates in a range of 25% to 35% above state average); or high likelihood of imminent, material cost pressures that could lead to higher rates	Extremely uncompetitive current or expected rates[8] in the state and/or compared to neighboring utilities on a consistent basis (e.g., average system rates more than 35% above state average); or currently in a period of persistent cost pressures that are causing material rate increases

8 Retail rates are typically calculated as average revenue per kilowatt hour sold; however, this factor may also be assessed based on competitive positioning of rates in a dominant customer class (residential, commercial, industrial or wholesale).

Factor 5: Financial Strength and Liquidity (30% Weight)

Why it Matters

A utility's ultimate credit profile must incorporate its financial metrics, as any public power utility that is substantially weaker than its peers in terms of liquidity, cash flow generated in relation to debt service, or debt relative to the value of its asset base will generally have a higher probability of default. Public power electric utilities, especially those that own generation, are typically capital intensive with an ongoing need to invest in their assets and have a higher leverage profile than their investor-owned counterparts, which typically necessitates consistent access to debt capital markets to assure adequate sources of funding. A utility's financial strength is key to its maintaining this market access and, in general, its long-term viability. Public power electric utilities with weaker metrics may find that their access to markets decreases rapidly when markets shift or their debt load is viewed as unsustainable.

When examining financial strength, there is no single measure that can predict the likelihood of default. We utilize metrics that are indicators for liquidity resources in relation to operating and maintenance expenses, the capacity of the issuer to service its debt and the size of its debt burden relative to its assets. Comparison to peers is typically useful.

How We Assess Financial Strength and Liquidity for the Scorecard

Adjusted Days Liquidity on Hand Ratio (10% weight)

The formula for Adjusted Days Liquidity on Hand Ratio (days) is as follows:

(Available unrestricted cash and investments + Eligible unused bank lines and capacity under commercial paper programs) x 365 days / (Utility's annual operating and maintenance expenses exclusive of depreciation and amortization expenses and the debt portion of annual payments made to JAAs under take-or-pay contracts)

For the numerator, certain designated reserves (but excluding debt service funds and reserve requirement) that are available when needed by the utility are included in unrestricted cash and investments. The unused portion of eligible bank lines (described below) are included. Capacity under commercial paper programs is included without duplication to unused eligible bank lines. Some utilities have commercial paper programs that are backed by letters of credit, and the unused portion is included when the LC issuing bank is rated P-1.

To be included in this ratio, eligible bank lines must meet all of the following criteria:

» Committed facilities

» Remaining tenor of committed drawdown availability is at least one year

» Absence of impediments to drawdown, including:

  – No material adverse change (MAC) representation requirement for borrowings

  – No material adverse litigation (MAL) representation requirement for borrowings

  – No covenants set at a level reasonably expected to restrict borrowings

» If bilateral, provided by a bank rated P-1

» If syndicated, provided by a group of banks predominantly rated P-1

Bank lines that do not meet the eligibility requirements are not included in calculating the ratio. However, depending on their strength, they may be assessed qualitatively as a credit positive if they constitute incremental liquidity as part of prudent financial policies. While bank lines over a year are included in the ratio, bank line maturities are considered in the broader context of a utility's future cash flow requirements, including capital expenditures, and loan/bond amortizations. Longer dated tenors are more favorable from a credit perspective.

Debt Ratio (10% weight):

(Gross debt – Debt service funds – Interest payable and debt service reserve funds) / (Gross fixed plant assets –Accumulated depreciation on plant + Net working capital)

Net working capital is defined as cash and investments plus receivables expected to be collected minus current liabilities unrelated to debt.

Adjusted Debt Service or Fixed Obligation Charge Coverage Ratio (10% weight)

In order to improve comparability between utilities that have chosen different generation procurement and financing strategies, there are some differences between their coverage ratios. For a public power electric utility that does not have any generation exposure via take-or-pay contracts with JAAs, we use the Adjusted Debt Service Coverage Ratio. For a utility that purchases some portion of its power under a take-or-pay contract with a JAA that has issued debt related to fulfilling that contract, we use the Fixed Obligation Charge Coverage Ratio.

Adjusted Debt Service Coverage Ratio:

(Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFTs) / Aggregate annual debt service

In the numerator, recurring revenue and recurring expenses exclude special, one-time items. Annual cash operating expenses exclude depreciation and amortization expenses. GFTs are general fund transfers.

Most public power utilities transfer a portion of their surplus revenues to a municipal government at an agreed upon level. While the transfers typically come after debt service in the legal flow of funds, in practical terms the transfer is a requirement that in many cases is made on a monthly basis. Therefore, our Adjusted Debt Service Coverage Ratio treats the transfer as akin to an operating expense, which differentiates it from the traditional bond ordinance debt service coverage ratio. We utilize the adjusted debt service coverage ratio in the scorecard because it provides a better overall indicator of a utility's operating results that provides greater comparability among public power electric utilities. In some cases, the bond ordinance coverage ratio may also be important to our analysis.

Fixed Obligation Charge Coverage Ratio:

(Annual recurring revenues plus interest income – Recurring annual cash operating expenses – GFT + Debt service portion of annual payments made to JAAs under take-or-pay contracts) / (Aggregate annual debt service + Debt service portion of annual payments made to JAAs under take-or-pay contracts)

In the numerator, recurring revenue and recurring expenses exclude special, one-time items. Annual cash operating expenses exclude depreciation and amortization expenses. GFTs are general fund transfers.

TAB 8

Énergie NB Power

NB Power's 10-Year Plan

Fiscal Years 2018 to 2027

Prepared: December 2016

NB Power's 10-Year Plan
Fiscal Years 2018 to 2027

Contents

Executive Summary

Under Section 101 of the *Electricity Act*, New Brunswick Power Corporation (NB Power) is required to prepare a strategic, financial and capital investment plan covering the next 10 fiscal years and file such plan with the Energy & Utilities Board (EUB) on an annual basis. This 10-year plan is for informational purposes but is to be taken into consideration during the review of general rate applications and in assessing NB Power's progress and forecasted ability to achieve long-term legislated goals and objectives. The following 10-year plan has been prepared in compliance with the requirements of the *Electricity Act* and covers the period of fiscal years 2017/18 to 2026/27.

The overarching financial goals of NB Power continue to be to reduce debt and create equity to provide NB Power with some flexibility to manage operating and financial risk, to respond to changing markets and technologies, and to better prepare for future investment requirements.

NB Power believes that progress towards achieving the financial goals should be made on an annual basis. It is committed to achieving these goals by continuing to establish a culture and philosophy of continuous improvement, managing costs, identifying new revenue streams and implementing an appropriate rate strategy.

One of the largest uncertainties facing NB Power over the course of the 10-year plan is the future of the Mactaquac Hydro Generating Station (Mactaquac). NB Power has recently announced its recommendation of a life achievement project to maintain Mactaquac to its intended lifespan of approximately 2068. For financial planning purposes, the 10-year plan has been updated to include the lower end of the range of life achievement estimates for the capital expenditures associated with NB Power's recommended option. The life achievement option meets all safety requirements, has the lowest cost estimate when compared to other options under consideration and allows NB Power to take into account changes in costs, technology, electricity demand and customer priorities going forward. In the coming months, NB Power will seek appropriate environmental approvals and follow application and review processes for financial approvals to be defined by the EUB.

In October 2016, a motion was introduced by the federal government to support ratification of the Paris Climate Change Accord (Paris Accord) and in December 2016, the federal government released the *Pan-Canadian Framework on Clean Growth and Climate Change*. This framework calls for carbon charges starting in 2018 that would continue to escalate until 2022 to help Canada meet the Paris Accord. In early December, the Province of New Brunswick also issued a new action plan, *Transitioning to a Low-Carbon Economy*, as part of a made-in-New Brunswick response to climate change that has recommendations on climate change that will impact NB Power. The implications to the 10-year plan resulting from current discussions and indications from the federal and provincial government are still uncertain but will result in increased costs over the course of the 10-year plan period. A range of the estimated increase in fuel and purchased power costs has been calculated based on the federal government's proposed carbon tax structure and a range has been provided to highlight the potential magnitude of the carbon tax structure's impact to net earnings and the potential resulting rate increases. The estimate is subject to variability but is nonetheless indicative of the potential future implications.

A summary of the key financial highlights of the 10-year plan is provided below in Figure 1.

Figure 1: Financial Highlights

Fiscal Year Ending March 31	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
(in millions $)										
Average Rate Increase	2.0%	2.0%	2.0%	2.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Gross Margin	1,016	1,054	1,095	1,089	1,128	1,141	1,169	1,146	1,166	1,136
Net Earnings	67	77	107	107	130	127	144	120	138	124
Return on Equity	13%	14%	16%	14%	15%	12%	13%	9%	10%	8%
Capital Expenditures	339	396	335	269	308	290	268	293	291	706
Net Debt	4,854	4,880	4,848	4,751	4,646	4,526	4,332	4,164	3,973	4,208
% Debt in Capital Structure	90.1%	88.9%	87.1%	85.2%	83.0%	80.7%	78.0%	75.6%	72.8%	72.4%
Potential Carbon Cost Impacts										
Estimate for Annual Cost of Carbon (in millions $)	-	20 - 40	30 - 65	55 - 115	65 - 130	95 - 190	85 - 170	105 - 210	90 - 185	115 - 230
Levelized Rate Change for Carbon (up to)		1.4%	1.4%	1.4%	2.4%	2.4%	2.4%	2.4%	2.4%	2.4%
Total Rate Impact (Average Rate Increase + Estimated Rate Change for Carbon Cost)	2.0%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%	3.4%

The *Electricity Act* calls for NB Power to move towards a minimum debt to equity ratio of 80/20. NB Power's Strategic Plan 2011-2040 identified the opportunity to achieve a capital structure of at least 80 per cent debt and 20 per cent equity by 2021. The current update to the 10-year plan focuses on making steady progress on an annual basis towards achieving this goal. Various operating pressures and increased capital expenditure requirements result in a delay in meeting the internal capital structure target until 2024, while maintaining NB Power's commitment to low and stable rate increases.

Rate increases are modelled throughout the period of the plan to allow for progress to be made in the debt to equity ratio while also reducing absolute debt levels. Should climate change initiatives proceed as proposed, additional rate increases may also be required throughout the 10-year plan. The magnitude of such rate increases will become clearer as further details emerge from the federal and provincial government plans.

As noted, the capital expenditures included for the Mactaquac project are reflective of the life achievement option. There are varying approaches associated with the life achievement option, with different spending amounts and varying timing for the capital expenditures. The 10-year plan includes a provision that is representative of the estimated lower end of the range of costs. The current estimated spending profile of this option has major spending commencing in 2027 with total expenditures of roughly $2.7 billion and spending continuing to 2036. The debt to equity ratio improves beyond the minimum legislated target of 80/20 beginning in 2024. This improved debt to equity ratio will allow for more financial flexibility, including the ability for NB Power to better prepare for the impact and potential variability of the Mactaquac costs and other future uncertainties around the cost of meeting climate change targets.

Additional information on details of the plan and the assumptions contained within can be found in the following sections:

- Appendix C – Statement of Cash Flow & Changes in Net Debt
- Appendix D – Balance Sheet

Corporate Overview

NB Power is a Crown Corporation, an Agent of the Crown and is the largest electric utility in Atlantic Canada. NB Power is responsible for the generation, transmission and distribution of electricity throughout New Brunswick and has five divisions: Customer Service, Generation (conventional), Nuclear, Transmission & System Operator, and Corporate Services.

New Brunswick Energy Marketing Corporation, a wholly-owned subsidiary of NB Power, conducts energy trading activities in markets outside New Brunswick.

As a provincial Crown Corporation, the owner and sole shareholder of NB Power is the Government of New Brunswick. NB Power reports to the Government through the Minister of Energy and Resource Development and the Government's expectations are expressed through legislation, policies and mandate letters.

Additional information on NB Power can be found on the corporate website at www.nbpower.com.

Mandate

NB Power's mandate is set by the *Electricity Act* of New Brunswick. Specifically, section 68 provides direction regarding

- rates charged by NB Power for sale of electricity within the province
- the management and operation of NB Power's resources and facilities for the supply, transmission and distribution of electricity within the province

The *Electricity Act* also establishes that, to the extent practical, rates charged by NB Power for sale of electricity within the Province shall be maintained as low as possible and changes in rates shall be stable and predictable from year-to-year.

In addition, the Minister, by way of a Mandate Letter, has given NB Power the responsibility for delivery of the following

- Maintaining and creating jobs in the resource sector in an economically sustainable fashion
- Working with the other Atlantic Provinces and neighbouring jurisdictions to improve regional cooperation
- Working with the federal government in ongoing investment and energy-related issues
- Meeting debt reduction targets as established in NB Power's 10-year plan
- Protecting and improving our environment

Strategy

NB Power is committed to a vision of sustainable electricity and to be our customers' partner of choice. There are three core values that are essential to the utility's success: Safety - Quality - Innovation.

NB Power's Board of Directors and management developed a long-term strategic plan as a foundation for NB Power's business plans, investment decisions and business initiatives. At the core of the Strategic Plan are three strategic objectives that guide the utility's actions and will enable the achievement of the corporate vision.

Strategy One

Become among the best at what we do

NB Power remains committed to becoming among the top-performing utilities in North America. For NB Power, becoming a top performer means excelling in a number of critical areas including safety, customer service, organizational, reliability, and environment. NB Power is in the process of developing a Corporate Excellence Plan, which will allow the utility to chart a path to becoming top quartile in key areas over time.

Strategy Two

Systematically reduce debt to ensure that NB Power is in a financial position to invest in new generation and transmission infrastructure where necessary to ensure stable rates for New Brunswick.

NB Power has committed to a reduction in debt over the period of the 10-year plan. This reduction in debt will represent a significant improvement to NB Power's capital structure and better align with other top performing crown-owned utilities. Through this debt reduction, NB Power will reduce its risk to rising interest rates and help ensure there is financial flexibility to make necessary investment decisions in the future.

Strategy Three

Invest in technology, educate customers and incent consumption that will reduce and shift demand (RASD) for electricity and ultimately defer or remove the next significant generation investment.

New Brunswick's use of energy is very seasonal and also can swing significantly at certain times of day. The peak load required in the winter is double the average load of the summer and, in any day, the load requirements may shift by as much as 500 MWs (requiring a plant the size of Belledune to be available for an hour or couple of hours of generation need). The swings are largely driven by the use of baseboard electric heat (60 per cent of New Brunswick residents).

Significant advancements in technology, such as smart grid, enable the customer to control and better manage their own energy use. Public awareness of energy consumption, the high costs of providing electricity, and the emergence of sustainable communities and homes, create an opportunity for NB Power to interact differently with its customers.

By executing on these three strategic objectives, NB Power will continue to provide value to the Province of New Brunswick and our customers and position ourselves as a North American leader in innovation in the electricity sector.

Additional information on NB Power's strategic plan can be found on the NB Power website at the following link: https://www.nbpower.com/en/about-us/accountability-reports/strategic-plans/

Integrated Resource Plan

NB Power's Integrated Resource Plan (IRP) is a long-term plan that considers economics, the environment, long-term societal interests and various sensitivities of these features. The most recent IRP was approved by the Shareholder and filed with the EUB in July 2014. A copy of this IRP can be found on the NB Power website at: https://www.nbpower.com/en/about-us/accountability-reports/strategic-plans/

The IRP analysis is part of a continual process that requires periodic load and resource updates as conditions change and evolve over time. The next formal IRP update is scheduled to be submitted to the EUB in 2017.

The development of the IRP required in-depth analysis in three key areas

1. Energy efficiency and demand considerations (also known as RASD) as well as supply considerations
2. Reliability and security of supply
3. Policy and regulatory considerations

The IRP presents the least-cost expansion plan encompassing both supply and demand options to meet forecasted NB Power in-province electricity requirements over a 25-year horizon. The 2014 Integrated Expansion Plan shown in Figure 2 reflects the following:

1. Energy efficiency, demand management and demand reduction is vital to the IRP. The IRP has included an aggressive but cost-effective RASD schedule that assumes a savings of approximately 600 MW and 2 TWh by 2038.

2. To encourage development of locally owned small-scale renewable projects, 75 MW of cost-effective community energy resources are targeted by 2020 to help meet the 40 per cent Renewable Portfolio Standard (RPS) requirement.

3. The current Mactaquac Hydro Generation Station's capacity and energy is assumed to be no longer available after 2030 because of the ongoing effects of Alkali-Aggregation Reaction (AAR) which is causing the concrete in the structures to expand. For the purpose of the IRP exercise, it was assumed that the capacity and energy is replaced, but with no assumption as to the replacement option or costs. [1]

[1] As this IRP was issued in 2014, the analysis supporting the life achievement option had not been completed at the time of its issuance. The next IRP update will be reflective of the specific implications associated with the recommended option for Mactaquac.

4. Millbank and Ste. Rose life extension is the most economic choice for continued peak load requirements in response to their scheduled retirement in 2031.

5. After the addition of new resources to meet the RPS and the Mactaquac replacement option, as well as Millbank and Ste. Rose life extension, no new capacity is needed to meet peak demand until after 2040.

6. Greenhouse gas levels to meet in-province load remain below the 2005 historical level of approximately five million tonnes.

Figure 2: Integrated Expansion Plan

In Service Date	Integrated Plan	Scheduled Retirements
2014	RASD Program Starts Here	
2020	75 MW Community Energy	
2026		Grand Manan (-29 MW)
2027		Bayside PPA (-285 MW)
2030	Mactaquac Replacement	Grandview PPA (-90 MW) Mactaquac (-668 MW)
2031	Millbank/Ste. Rose Life Ext.	Millbank/Ste. Rose (-496 MW)
2032		Twin Rivers PPA (-39 MW)

In summary, the strategic direction recommended over the immediate term in the IRP is

- Initiation of a community energy program to contribute to the RPS
- Continuation of RASD programs with increased development in the long-term
- Continuation of technical work with regards to new generation options that might be viable in New Brunswick, especially options from renewable resources

The assumptions contained within the 10-year plan are consistent with the integrated expansion plan noted above.

Key Assumptions / Sensitivities

The assumptions incorporated into the 10-year financial plan were compiled based on a combination of information obtained from internal resources, market indications and from external consultants or publications. A listing of key assumptions factored into the 10-year plan is provided in Appendix A. A table outlining the sensitivity to costs based on changes to certain key assumptions is also presented in Appendix B.

Mactaquac project sensitivity

As has been noted, the 10-year financial plan is reflective of a life achievement option with respect to Mactaquac. There are however varying approaches that have been assessed that would result in the intended lifespan of Mactaquac being achieved. The approaches vary in the specifics of the work to be completed and differ in total spending requirements and in the timing of when the spending occurs. For financial planning purposes, the lower end of the range of estimated costs has been reflected in the 10-year plan. Figure 3 below provides some sensitivity information to illustrate the changes to the 10-year plan that would occur if the higher end of the range of estimated costs were modelled, assuming the same rate increases. The variance in the capital requirements and revised net income, net debt, and % debt in capital structure amounts have been presented for informational purposes.

Figure 3: Mactaquac Project Sensitivity

Fiscal Year Ending March 31	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
(in millions $)										
Upper range of estimated capital expenditures	11	11	12	4	42	173	184	282	364	300
Capital expenditures included in plan	11	11	12	9	12	15	18	51	58	365
Variance	-	-	-	(6)	30	158	166	231	307	(65)
Revised financial highlights										
Net Earnings	68	77	105	105	132	145	164	122	146	132
Net Debt	4,854	4,881	4,850	4,749	4,673	4,693	4,647	4,709	4,820	4,986
% Debt in Capital Structure	90.1%	88.9%	87.2%	85.3%	83.1%	81.1%	78.7%	77.3%	75.9%	75.0%

Material Risks and Uncertainties

In the normal course of operations, NB Power's net earnings can vary significantly from forecasted results due to changes in factors such as fuel and purchased power prices, foreign exchange rates, interest rates, weather, hydro flows and other various risk items. Information on some of the key factors that could impact actual results from the forecast presented in the 10-year financial plan is provided below.

Point Lepreau Nuclear Generating Station (PLNGS) capacity factor – Fuel and purchased power costs could differ materially if the assumed PLNGS capacity factor is not achieved.

Export contracts – The forecast assumes that NB Power will renew certain existing export contracts as they expire and achieve certain margins on these contracts. Failure to be the successful bidder on these contracts or to renew at forecasted margin levels will impact results.

Market conditions – Volatility in near-term fuel and purchased power prices and the Canadian dollar is largely managed through NB Power's financial hedging program. In the mid to long term, NB Power is subject to changes in commodity prices and exchange rates.

Interest rates – Given NB Power's debt levels, volatility in interest rates can have a significant impact on results as existing debt issues mature and need to be refinanced, as new debt needs to be issued to cover significant capital expenditures, or as short-term debt costs fluctuate based on market movements.

Natural gas supply – Uncertainty exists around the future source of supply and the related pricing of natural gas. The forecast is based on current estimates for the pricing of natural gas. Variations in the actual supply and price could vary from assumptions and result in fluctuations in fuel and purchased power costs.

Economic conditions – If future load growth falls short of the forecast or if there are unanticipated industrial closures this could materially impact forecasted in-province revenue.

Used nuclear fuel management and decommissioning – Liability and funding estimates for used fuel management reflect current engineering estimates. These estimates include cash flows which extend out over 150 years and are therefore subject to change. Revised estimates could impact annual used fuel management and decommissioning costs as well as overall funding requirements.

Hydro generation – The forecast is based on expected long-term average hydro flows. When actual flows are below anticipated levels, other more expensive fuels are used to account for the shortfall, thereby increasing generation costs in province and reducing energy available for export. Conversely, when flows are higher than anticipated, hydro generation reduces the use of expensive fuels and decreases generation costs. In-year hydro flows that differ substantially from long-term average can materially impact fuel and purchased power costs.

Regulatory framework - The *Electricity Act* includes a regulatory framework that results in all of NB Power subject to regulatory oversight by the EUB and requires NB Power to seek approval of its rates annually, regardless of the amount of rate change. The forecasted annual rate increases included in the plan are subject to EUB approval. If the forecasted rate increases, or some portion of which were not approved, then revenue projections could vary materially. A reduction in a rate increase in the earlier years of the plan can adjust results significantly over the period due to the cumulative impact that a rate increase can have in future years.

Mactaquac project - Projected net earnings and debt level projections are subject to change based on the final approval of the recommended option for Mactaquac. Final cost estimates and the timing of expenditures will be reviewed as part of the regulatory process.

System reliability and risks – The forecast is based on specific assumptions around planned plant outages and interconnection opportunities with neighboring utilities. Any unplanned interruption of plant facilities or interconnection points may result in additional costs to NB Power for fuel and purchased power.

Carbon costs – The 10-year plan has illustrated separately a preliminary estimate of the potential cost of carbon legislation. The implementation of climate change actions during the forecast period could materially impact fuel and purchased power costs, export revenues or future capital expenditure requirements.

Revenue Requirement

NB Power's costs are driven by the cost of fuel and purchased power, costs required to run and maintain operation of the utility, capital investments and recovery of regulatory deferral account balances.

NB Power's forecasted revenues, expenses and net earnings for the 10-year period ending in 2027 are presented in Figure 4.

Figure 4: Forecasted Revenue Requirement

Fiscal Year Ending March 31	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
(in millions $)										
Revenues										
Sales of power										
In-province	$ 1,429	$ 1,453	$ 1,481	$ 1,529	$ 1,541	$ 1,555	$ 1,568	$ 1,582	$ 1,596	$ 1,621
Out-of-province	223	229	226	176	181	195	206	213	217	227
Miscellaneous	74	78	80	88	91	99	103	105	107	110
	1,726	1,760	1,788	1,793	1,813	1,849	1,876	1,900	1,919	1,958
Expenses										
Fuel and purchased power	636	629	613	616	595	609	605	649	646	712
Operations, maintenance and administration	496	499	486	478	498	517	530	521	533	522
Depreciation	251	273	285	292	292	298	304	304	305	314
Taxes	44	45	46	47	48	49	50	51	52	53
	1,426	1,445	1,430	1,433	1,433	1,473	1,489	1,524	1,536	1,601
Earnings before undernoted items	300	315	358	360	380	377	388	375	383	357
Finance charges and other income	222	226	238	240	237	237	230	217	205	191
Net changes in regulatory balances	11	12	13	13	13	13	14	38	40	42
Net earnings	**$ 67**	**$ 77**	**$ 107**	**$ 107**	**$ 130**	**$ 127**	**$ 144**	**$ 120**	**$ 138**	**$ 124**

Sales of Power - In-Province

Load in New Brunswick is forecasted to grow minimally during the 10-year period. Normal growth is partially offset by the impact of RASD and efficiency programs. These programs are expected to reduce energy consumption in the Province by approximately 1,043 GWh by 2027.

Annual rate increases of two per cent are modelled annually up to 2021, and one per cent annually thereafter in pursuit of achieving a capital structure of at least 20 per cent equity and to better prepare for the future rate impacts of the Mactaquac project and other future cost uncertainties. Planned rate increases are uncertain pending the final decisions and the impact of applicable cost estimates related to Mactaquac and potential carbon pricing implications (see page 3). Refer to the In-Province Load section for additional information on load growth and rate increases.

Sales of Power - Out-of-Province

NB Power takes advantage of its geographical location and diverse generation mix to sell surplus energy into neighboring jurisdictions such as Prince Edward Island, Nova Scotia, Quebec and New England. Out-of-province sales benefit in-province customers by keeping rates lower than they otherwise would be.

The forecast assumes that all excess capacity is used to export energy when it is economic to do so, that is, when market prices are forecasted to be higher than the cost to supply. An assessment has been made on the expected ability to retain or renew existing export contracts for the forecast period, considering NB Power's historical relationship with parties and any competitive / lack of competitive advantage in the marketplace that NB Power may have. The forecast does not reflect new export contracts or other sales arrangements.

Miscellaneous Revenue

Miscellaneous revenue is comprised mainly of revenue derived from water heater rentals, transmission tariff, connection and surcharge fees, pole attachment fees, third-party work performed for other utilities, customer contributions and forecasted revenue for new products and services. The forecast includes a high-level estimate for an increase in revenue attributed to new products and services offerings. The amount and timing of these revenues are subject to change, depending upon their success and the ultimate timeline and specific offerings to be rolled-out.

Fuel & Purchased Power

Fuel expense reflects the cost of oil, coal, petroleum coke and diesel fuel used in NB Power's thermal stations as well as the cost of uranium used at the PLNGS. NB Power purchases energy and capacity under long-term purchase agreements from wind, hydro, biomass and natural gas generators in the province as well as through market electricity purchases from utilities in neighbouring jurisdictions.

Fuel & purchased power expenses over the forecast period are driven by

- In-province load and export sales volumes
- Changes to forecasted commodity and market prices
- Biennial maintenance outages at PLNGS (post 2019)
- Biennial maintenance outages at Belledune Generating Station

Operations, Maintenance & Administration (OM&A)

OM&A includes labour, materials, hired services, travel, insurance and other costs associated with operating and managing the utility. NB Power is committed to continuous process improvement and cost management. The plan reflects a continued commitment to cost reductions by way of process reviews and efficiencies, regional collaboration, technology improvements and automation.

The OM&A figures between 2018 and 2020 include additional expenditures for reliability improvements at PLNGS. Efficiencies from these expenditures are forecasted to result in a return to a more historical OM&A expense in 2021. Generally, OM&A expense is forecasted to increase annually by inflation, which is forecasted at two per cent. Other year-over-year swings are largely reflective of the implications of the biennial maintenance outage cycle for PLNGS which results in a higher allocation to capital during an outage year.

Depreciation

Depreciation expense is driven by NB Power's investment in assets. The depreciation of assets is based on useful service lives and the straight-line method of depreciation is used for all assets. Depreciation expense also reflects a component of charges to income to account for the future decommissioning of generating stations and the management of used nuclear fuel.

Depreciation expense increases over the forecast period due to ongoing investments in generating stations and in the distribution and transmission infrastructure.

Taxes

NB Power is subject to property tax, utility tax and right of way tax. Taxes are assumed to escalate at modest rates during the forecast period.

Finance Charges and Other Income

NB Power uses a combination of long and short-term debt to finance its operations and all principal and interest is payable to the Province of New Brunswick. NB Power incurs a debt portfolio management fee (0.65 per cent of debt outstanding at the end of the prior fiscal year) that is also payable to the Province of New Brunswick as a result of these borrowing arrangements.

Other components of finance charges offset interest expense and the debt portfolio management fee. These include earnings on investment and sinking funds and interest during construction (IDC), which capitalizes the interest expense related to the funds expended on capital projects not yet in service (work-in-progress).

Finance charges also include an expense that recognizes the time value of money on the estimated expenditures for the decommissioning and used fuel management liabilities. It is generally referred to as an accretion expense and essentially represents an annual interest charge on these forecasted liability balances.

During the forecast period, both long-term and short-term interest rates are expected to increase, resulting in higher interest expense. Accretion charges also increase over time due to the increasing liability balances. These cost increases are offset or partially offset in some years by a reduction in overall debt levels and higher earnings on the investment and sinking funds. In 2027, finance charges also decrease due to an increase in interest capitalized to the Mactaquac project during the construction period.

<u>Net Changes in Regulatory Balances</u>

Regulatory Deferral – Point Lepreau Refurbishment
Pursuant to the *Electricity Act*, certain costs incurred during the PLNGS refurbishment outage were accumulated as a regulatory asset and are being amortized and recovered from customers over the life of the refurbished Station.

Regulatory Deferral – PDVSA[2] Settlement
In August 2007, the EUB approved the implementation of a regulatory deferral account to enable the savings associated with the lawsuit settlement with PDVSA to be provided to customers on a levelized basis over a period of 17 years. The deferral is being amortized over the remaining life of Coleson Cove Generating Station. In 2025, the net changes in regulatory balances amount increases as the benefit allocated to customers resulting from the PDVSA settlement is completed in 2024.

In-Province Load

During the summer of 2016, NB Power completed a 10-year Load Forecast for the 2018 to 2027 period. The key assumptions used in this forecast include:

- Average Gross Domestic Product growth of 1.0 per cent annually based on the Provincial Government's Economic Outlook released in March 2016
- Known major industrial additions and load changes based on account manager input and public announcements
- The addition of approximately 14,500 new year-round residential customers by 2027 based on historical customer growth trends and population projections
- Normal weather (4,650 heating-degree-days) based on a rolling average using the latest 30 years
- Estimates of energy reduction from NB Power's RASD program, including Smart Grid innovations and Energy Efficiency programs
- Penetration of electric space heating, water heating and air conditioning based on NB Power's 2013 Energy Planning Survey of residential customers

Figure 5 shows the total forecasted in-province load and year-over-year growth.

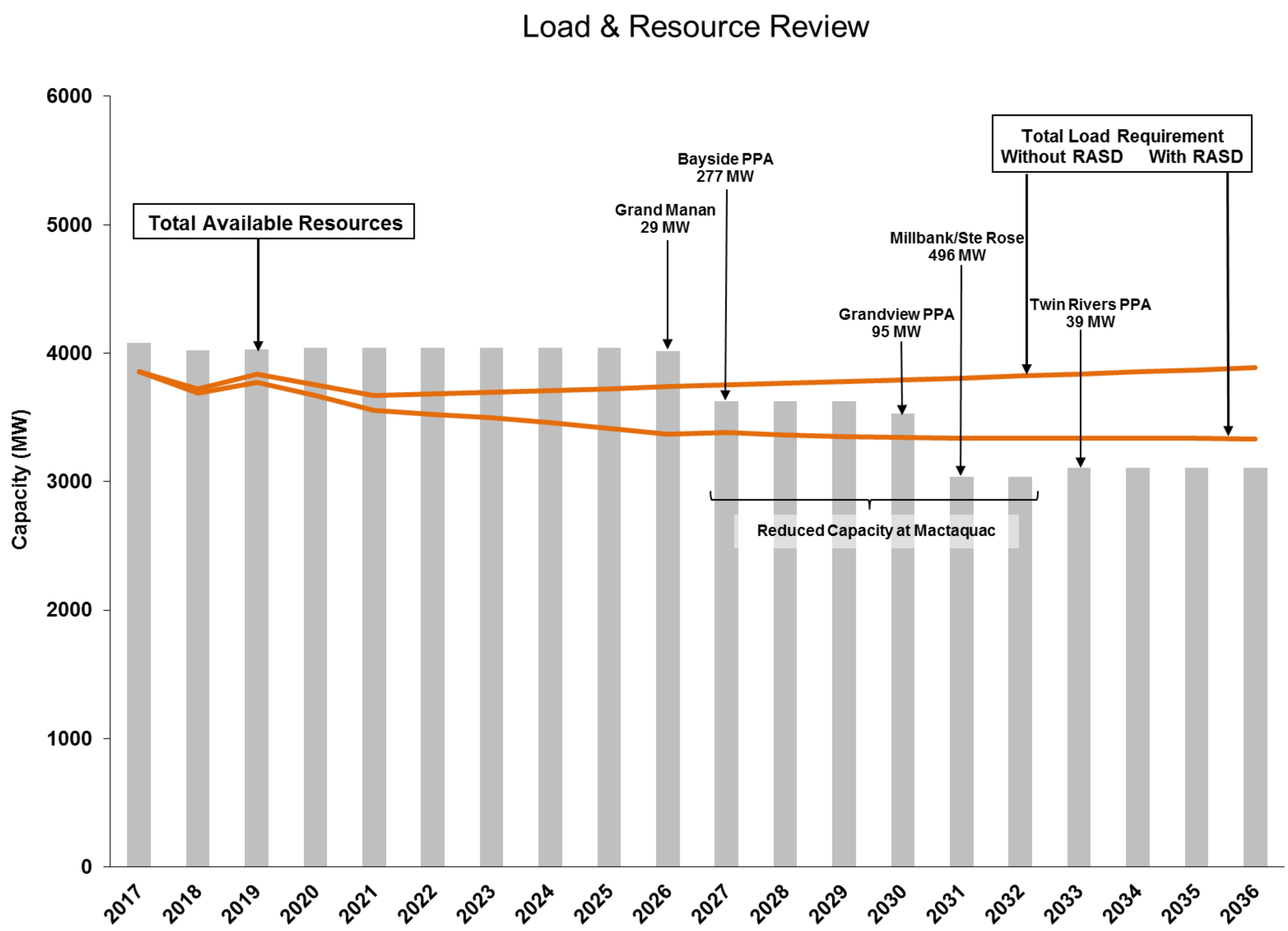
[2] Petróleos de Venezuela, S.A.

Figure 5: Forecasted In-Province Load

Fiscal Year Ending March 31	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
(in GWh)										
Residential	5,282	5,290	5,293	5,289	5,282	5,265	5,245	5,218	5,191	5,208
Industrial	4,295	4,290	4,351	4,617	4,599	4,606	4,594	4,609	4,608	4,651
General service	2,379	2,350	2,330	2,318	2,313	2,313	2,320	2,331	2,343	2,362
Wholesale	1,269	1,264	1,260	1,256	1,255	1,256	1,255	1,256	1,255	1,264
Street lights	44	44	44	45	45	45	45	46	46	46
Sub-total	13,270	13,238	13,278	13,526	13,495	13,485	13,460	13,459	13,443	13,530
Losses	842	841	839	845	844	845	843	842	842	842
Total In-Province Load	**14,112**	**14,079**	**14,118**	**14,371**	**14,339**	**14,329**	**14,303**	**14,301**	**14,284**	**14,372**
Residential	0.4%	0.1%	0.1%	-0.1%	-0.1%	-0.3%	-0.4%	-0.5%	-0.5%	0.3%
Industrial	-1.0%	-0.1%	1.4%	6.1%	-0.4%	0.1%	-0.2%	0.3%	0.0%	0.9%
General service	0.0%	-1.2%	-0.9%	-0.5%	-0.2%	0.0%	0.3%	0.5%	0.5%	0.8%
Wholesale	1.4%	-0.4%	-0.3%	-0.3%	-0.1%	0.1%	0.0%	0.1%	-0.1%	0.7%
Street lights	-2.7%	0.9%	0.5%	0.7%	0.7%	0.4%	0.4%	0.7%	0.2%	0.2%
Total In-Province Load Growth	**0.0%**	**-0.2%**	**0.3%**	**1.9%**	**-0.2%**	**-0.1%**	**-0.2%**	**0.0%**	**-0.1%**	**0.7%**

RASD and efficiency programs are forecasted to reduce energy consumption in the province by 1,043 GWh by 2027. The impact this reduction has on future supply requirements in the IRP is illustrated in Figure 6.

Figure 6: Impact of RASD



In-Province Revenue

The Class Cost Allocation Methodology has been reviewed and approved by the EUB. Future rate increases will vary by customer class to continue to move toward all customer classes being within a revenue to cost ratio of .95 – 1.05 (range of reasonableness). Although future rate increases may be different by rate class, the overall increase will equal the average rate increase (e.g., 2 per cent). Figure 7 shows the average forecasted annual rate increases, excluding the potential impact of carbon costs, and the resulting revenue, based on the sales projections reflected in Figure 5.

Figure 7: Forecasted Annual Rate Increases and In-Province Revenue

Fiscal Year Ending March 31	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Average Rate Increase	**2.0%**	**2.0%**	**2.0%**	**2.0%**	**1.0%**	**1.0%**	**1.0%**	**1.0%**	**1.0%**	**1.0%**
Total In-Province Sales of Power	**$ 1,429**	**$ 1,453**	**$ 1,481**	**$ 1,529**	**$ 1,541**	**$ 1,555**	**$ 1,568**	**$ 1,582**	**$ 1,596**	**$ 1,621**

Capital Plan

The 10-year plan calls for capital expenditures of approximately $3.5 billion over the next 10 years. This total is inclusive of part of the provision for Mactaquac in the range of $560 million. A final decision on the end-of-life option for Mactaquac requires a regulatory review and approval process. NB Power is also planning to invest in technologies and processes to support the RASD strategic initiative over the period of the plan. Additional ongoing investments will also be required to maintain, upgrade and expand the generation, transmission and distribution assets that generate and deliver electricity to the customers throughout the province. A breakdown of forecasted spending is provided in Figure 8.

Figure 8: 10-Year Capital Plan

Fiscal Year Ending March 31	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
(in millions $)										
Mactaquac	$ 11	$ 11	$ 12	$ 9	$ 12	$ 15	$ 18	$ 51	$ 58	$ 365
Reduce and Shift Demand Projects										
RASD - New Capabilities & Energy Related Products & Services	23	28	31	22	17	10	9	3	3	3
RASD - AMI	4	49	32	2	1	1	1	1	1	1
Major Outage / Inspection Expenditures	75	65	41	65	55	47	42	52	45	52
General Capital Expenditures	225	243	219	171	224	217	197	187	185	285
Total Capital Expenditures	**$ 339**	**$ 396**	**$ 335**	**$ 269**	**$ 308**	**$ 290**	**$ 268**	**$ 293**	**$ 291**	**$ 706**

Mactaquac

A major capital project during the 10-year forecast period revolves around the future of Mactaquac. The current expected end of service life for the concrete structures at the Station with the ongoing maintenance program is 2030 based on engineering estimates. The Station produces about 1.6 TWh annually and can produce 672 MW at full capacity.

Since it was constructed in the late 1960’s, the Station has provided New Brunswickers with low cost, reliable, emission free energy. In the 1980’s, it was determined that a condition known as Alkali Aggregate Reaction (AAR) was causing the concrete in the structures to expand. The AAR growth rate has been steady and sustained.

NB Power has evaluated options for addressing the end of service life of the concrete structures as follows:

- Repower by replacing the spillway and powerhouse
- No power and maintain the head pond by replacing the spillway but not the powerhouse
- Remove the spillway, powerhouse and earthen dam

In parallel with this work, NB Power determined the possibility of operating the current concrete facilities beyond 2030, within the footprint of the existing facilities, through a modified intensive maintenance program and replacement of aged equipment. A life achievement option has been proven to be technically feasible and is the option being recommended by NB Power. The recommendation follows three years of expert research and input from First Nations and the public that resulted in several public reports examining the options. An independent third party was engaged to review the decision making process and provided an expert report to the executive and the NB Power Board. This recommendation follows a fact-based decision process balancing environmental, social, technical, and cost considerations.

For modelling purposes, the lower end of the range of estimated costs for the life achievement option was selected as the basis for this 10-year plan. As well as being the least cost option, the spending profile of the life achievement option also results in major spending starting later than originally planned. The major spending for the range of costs modelled in the 10-year plan does not begin until 2027, which is farther out in time than would have been expected or forecasted in previous 10-year plans which modelled a repower option that required higher capital expenditures in the near term. In the coming months, NB Power will seek appropriate environmental approvals with the Province of New Brunswick and follow application and review processes for financial approvals to be defined by the Energy and Utilities Board.

RASD

The RASD program that is reflected in the capital plan is a collection of initiatives and projects that are needed to fulfil the strategic objective to invest in technology, educate customers and incent consumption that will reduce and shift demand for electricity and ultimately defer the next significant generation investment.

RASD can be broken down into three major streams of activities. The first is customer focused conservation and energy efficiency efforts. The second is investments made by NB Power in the infrastructure, information and communication technologies commonly referred to as the "Smart Grid" that will enable products, services, solutions and programs that have the potential to reduce demand and energy requirements. The third stream is improvements to operating processes and core capabilities that will improve the utility's ability to manage current and future infrastructure and ongoing grid operations.

NB Power has entered into a multi-year agreement with Siemens Canada to integrate Smart Grid technology into the province's electrical system. This agreement will allow NB Power to continue to offer its customers low and stable rates by modernizing the provincial electrical system.

NB Power and Siemens have developed a comprehensive Smart Grid deployment program. The program is designed so that all of the activities become building blocks for future value creation. Each section of the program can stand alone, providing some flexibility in the timing of their delivery. NB Power will measure the progress of the RASD program through a number of Key Performance Indicators (KPIs).

By automating and shifting electricity usage to times of day when there is less overall need, NB Power will be able to use lower cost generating assets to meet its requirements and delay the need to build new generating stations in the future. Implementing Smart Grid programs will enable customers to better control and manage their energy usage. Customers will have more choices about how and when they use their electricity in the future through new technologies, including

- Programmable "smart" thermostats that can participate in load shifting programs
- Energy smart appliances and products, such as smart water heaters
- In-home and in-business products and services that enable energy (load) shifting
- Energy information dashboards
- Renewable energy-based products such as solar panels and other forms of distributed energy

New technologies such as Advanced Metering Infrastructure (AMI) will enable NB Power to better understand customers' electricity usage in real time by engaging with customers and supporting them to reduce and shift their electricity patterns. This will provide NB Power with the opportunity to reshape the rising demand on the electricity system into the future.

An AMI is the underlying foundation to our Grid modernization program. The many benefits of AMI include providing the best tools and programs to our customers so they are able to manage their costs/consumption information (demand and energy) effectively and efficiently. NB Power planning and operations will also leverage this functionality for the purpose of providing new customer focused programs and services in the future. Within NB Power's day to day operations AMI will also increase efficiency of meter data collection, billing, and disconnects/reconnects. Power restoration will also be improved as a result of knowing when a customer's power is out and having access to additional information to better pinpoint the cause of the outage which on average could reduce the time to restore. The RASD strategy and the Grid modernization program with AMI is considered in NB Power's long term Integrated Resource Plan.

Major Outage / Inspection Expenditures

Major outage and inspection expenditures reflect the forecasted costs for planned outages and inspections at the nuclear and thermal generating stations. Major outage and inspection expenditures reflect periodic outage assumptions for the Point Lepreau and Belledune generating stations and other various outage costs associated with the remaining thermal facilities.

General Capital Expenditures

NB Power's 10-year capital plan has been strengthened with the corporate wide rollout of standard project management methodology, including a more robust process at the identification phase of a project and continuous improvement in future capital planning. NB Power's Investment Governance Framework includes capital review committees at both the corporate and divisional level. The corporate level committee is responsible for oversight of the corporation's investment governance framework and both it and the divisional committees are responsible for vetting capital requirements within the 10-year plan. The inputs to the 10-year capital plan have strengthened as technology advancements provide information regarding asset and system health, asset criticality, condition assessments and equipment obsolescence not available in the past.

NB Power is forecasting general capital expenditures, on average, of approximately $215 million per year over the next 10 years. All of NB Power's generating stations were built decades ago and require continuous investment to ensure safe and reliable operation. Similarly, continuous investments are required in the transmission and distribution system to ensure reliability, the safety of employees and the public, and to meet customer growth in the province. Annual expenditures on information technology hardware and software, communications equipment, vehicles, tools and equipment are necessary to support day-to-day operations.

In addition to capital investments made to “keep the lights on”, NB Power also considers capital investments that are intended to provide economic benefits, that is, to reduce operating costs, increase revenues or a combination of both. NB Power’s investment governance process evaluates potential projects across the company to determine which projects should be included in the capital plan to meet the requirements of the assets within the available capital and human resources.

There are many types of capital projects and programs but they can largely be categorized as follows

- Asset reliability projects include generation facility, substation, terminal, transmission and distribution system reliability and upgrade projects to address equipment aging, obsolescence and reliability improvements. Also included in this category are vehicle purchases, tools and equipment and property improvements.
- Obligation to serve projects include work in response to customer demands (thousands of smaller dollar work orders), water heater purchases and a portion of planned system improvements that are related to load growth, joint use (i.e., used by other utilities in the province) and road shift projects.
- Safety and regulatory compliance projects include replacement of deteriorated assets which are a potential safety risk and projects that are required to maintain operating licenses, including Point Lepreau Generating Station, or meet regulatory requirements.
- Asset optimization/productivity projects include improvement projects that typically have a short payback period and provide benefits and present value savings to the organization.

Carbon Costs

On October 3, 2016, the Prime Minister introduced a motion to support ratification of the Paris Climate Change Accord and on December 9th, 2016, the federal government released the *Pan-Canadian Framework on Clean Growth and Climate Change*. Among other things, this framework proposes to set a national benchmarking requirement of $10/tonne of CO_2 by 2018, which would rise by $10 each year to $50/tonne in 2022, in order to help Canada meet the Paris Accord. Provinces can choose to meet this requirement either through directly pricing CO_2 (in the form of a tax), or they can adopt cap-and-trade systems, which must meet the same annual emission reductions expected from the benchmark pricing requirements. The framework notes that provinces will have the flexibility in deciding how to implement carbon pricing but the federal government will provide a pricing system for any province that does not adopt one of the two systems by 2018.

The implications of a price on carbon as outlined above could potentially result in significant increases in costs to NB Power. The impact of carbon pricing could affect the financial results of the 10-year plan in a number of ways. The major cost considerations would include items such as:

- an increase in fuel and purchased power costs, both by way of a tax and also an expected increase in electricity market prices
- a decrease in the ability to export, reducing export margins
- increased renewable energy requirements, either through new builds or purchased power agreements
- potential transmission systems reinforcements to ensure reliability and accommodate changes to transmission flows or import levels
- stranded asset costs of fossil fuel plants that may not be able to operate to the end of their planned life

Although revenues from carbon pricing are to remain within the provinces of origin, it is not clear as to how or if those revenues would come back to benefit ratepayers to offset some of the potential cost implications noted above.

Additional analysis and an evaluation of potential mitigating actions are still required but a preliminary estimate of the impact to fuel and purchased power costs was completed based on the carbon charge system outlined above that was proposed by the federal government. A system dispatch was rerun for the 10-year plan period that included a carbon charge on emissions starting at $10 / tonne in 2018 and rising to $50/tonne by 2022 with general escalation thereafter. An increase was also assumed to occur in general market prices for electricity over the period, ranging from $5/MWh to $25/MWh. The amounts vary by year on account of the biennial PLNGS outages but the preliminary analysis identified an increase in annual fuel and purchased power costs of roughly $40 million in 2018, increasing to upwards of $230 million by the end of the 10-year plan. It is possible that some portion of these costs may be able to be reduced through mitigating activities but it is not known as to what costs or capital expenditures would be required to reduce the charges. In any event, carbon pricing has the potential to significantly impact and alter this 10-year plan, the magnitude of which will become clearer as further clarity and details emerge from the federal and provincial governments.

Conclusion

NB Power's future is one that is filled with both challenges and opportunities. By striving to position the utility as a North American leader in innovation in our industry, aggressively controlling costs, and focusing on customer service, safety, reliability and the environment, NB Power will endeavour to achieve its mission, vision and plan objectives.

Challenges exist in balancing the desire for stable and predictable rates while providing safe and reliable energy, investing in the future, and building up an appropriate debt to equity structure. A major decision exists with respect to Mactaquac, one that will not only impact the period of this plan but for many years thereafter. A challenge also exists in adapting to potential carbon pricing structures that are forthcoming. The impact of carbon pricing could significantly alter how NB Power operates its generation fleet and result in changes to future capital expenditures and the rates required to be charged to customers. Greater certainty on the financial outlook of the next 10 years will be achieved once the decision on Mactaquac has been approved and clarity is attained on what actions are to be taken within the Province and in neighboring jurisdictions with respect to carbon.

Appendix A – Key Assumptions

A listing of key assumptions factored into the 10-year financial plan is outlined below in Figure 9.

Figure 9: Key Assumptions

Fiscal Year Ending March 31	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Financial, Economic & Market Assumptions										
Consumer price index	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%
Average rate increase	2.0%	2.0%	2.0%	2.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%
Short-term interest rates	1.0%	1.9%	2.8%	3.5%	3.8%	3.9%	4.0%	4.0%	4.0%	4.0%
Long-term interest rates	4.3%	5.2%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
Foreign exchange rate ($CDN/$US)	0.78	0.78	0.78	0.81	0.83	0.84	0.85	0.85	0.85	0.85
Heavy Fuel oil price ($US/bbl)	42.30	45.25	48.14	48.91	51.09	53.03	55.02	57.87	60.39	62.23
Coal price ($US/ton)	62.79	59.78	60.02	62.19	64.12	65.53	66.97	68.45	69.93	71.47
Petcoke price ($US/ton)	54.16	57.90	59.43	61.59	63.50	64.89	66.32	67.78	69.25	70.77
Natural gas price - winter ($US/mmbtu)	7.87	6.84	6.91	7.56	7.79	8.05	8.31	8.58	8.85	9.13
Natural gas price - summer ($US/mmbtu)	3.20	3.92	3.66	4.22	4.44	4.69	4.93	5.18	5.43	5.70
Mass Hub electricity price - winter ($US/MWh)	52.55	51.06	52.45	53.65	54.85	56.04	57.24	59.37	60.85	64.90
Mass Hub electricity price - summer ($US/MWh)	30.65	31.89	30.97	34.22	37.46	40.71	43.95	45.97	47.75	49.84
Continuous improvement savings ($ millions)	5.00	10.00	20.00	30.00	30.60	31.21	31.84	32.47	33.12	33.78
Load & Generation Assumptions										
In-province load (GWh)	14,112	14,079	14,118	14,371	14,339	14,329	14,303	14,301	14,284	14,372
Out-of-province load (GWh)	2,923	2,744	2,767	2,102	2,214	2,283	2,510	2,347	2,527	2,425
Point Lepreau capacity factor	89%	82%	96%	81%	96%	84%	96%	84%	96%	84%
Hydro generation (GWh)	2,756	2,758	2,758	2,758	2,758	2,758	2,758	2,758	2,758	2,758
Thermal generation (GWh)	3,549	3,665	2,965	3,484	3,228	3,882	3,613	3,862	3,518	4,074
Nuclear generation (GWh)	5,099	4,723	5,556	4,699	5,550	4,866	5,566	4,866	5,550	4,866
Purchases (GWh)	5,630	5,677	5,606	5,532	5,016	5,106	4,876	5,162	4,985	5,098
Total sources of supply (GWh)	17,035	16,823	16,885	16,473	16,553	16,612	16,813	16,648	16,811	16,797

Appendix B – Sensitivity Table

Figure 10: Sensitivity Table

Fiscal Year Ending March 31	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
(in millions $)										
1% change in rate increase (annual impact)	14	14	14	15	15	15	15	16	16	16
5 cent change in foreign exchange rate (USD / CAD) [1]	3	8	11	19	18	18	18	19	20	21
$1 change in natural gas prices [1]	9	10	10	10	10	9	9	7	5	0
$5 change in coal and petcoke prices [2]	2	2	2	2	2	8	7	8	7	8
$5 change in purchased power prices [1]	6	9	11	10	10	10	10	10	10	10
10% change in sales price of exports	12	12	19	15	16	17	18	19	19	20
10% change in long-term average of hydro [3]	18	18	18	18	17	18	19	20	21	22
1% change in the capacity factor of Point Lepreau [3]	4	4	4	4	4	4	4	4	4	5
1% change in OM&A expenses	5	5	5	5	5	5	5	5	5	5
1% change in long-term interest rates [4]										
- current year impact	1	2	4	2	1	1	0	0	0	0
- full-year impact	5	4	5	3	4	2	0	0	0	1
1% change in short-term interest rates	9	10	10	9	8	8	7	6	6	6
10% change in weather heating degree days [5]	48	49	50	51	52	53	54	55	56	57
1% change in discount factor for Nuclear decommissioning/UFM	19	19	19	19	19	19	19	19	19	19
1% change in long-term investment/sinking funds earning [6]	12	13	13	12	13	13	14	14	16	17

Notes:

1. Sensitivities in 2017/18 are reduced due to firm contracts or through financial instruments entered into.
2. Sensitivities in early years are reduced due to firm contracts entered into.
3. Based on an incremental purchased power replacement energy cost for each year.
4. Current year impact amount reflects the impact in the year resulting from the timing of the debt issue. The full year impact amounts reflects an annualized impact.
5. Reflects the impact to in-province revenue only - does not include the impact on fuel and purchased power - therefore does not reflect a net earnings impact.
6. Reflects the approximate current year impact of a change in the earnings rate on an annualized basis, amounts are not cumulative.

Appendix C – Statement of Cash Flow & Changes in Net Debt

Figure 11: Statement of Cash Flows

Fiscal Year Ending March 31	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
(in millions $)										
Operating activities										
Net earnings	67	77	107	107	130	127	144	120	138	124
Depreciation and amortization	251	273	285	292	292	298	304	304	305	314
Other operating cash-flow adjustments	18	(5)	(8)	(3)	1	(8)	(10)	12	8	(7)
Net change in working capital items	13	7	(43)	(54)	(4)	(4)	(5)	(5)	(5)	(5)
Cash provided by operating activities	348	352	341	343	419	412	434	431	446	427
Investing activities										
Expenditure on property, plant and equipment	(331)	(388)	(328)	(262)	(301)	(282)	(258)	(281)	(276)	(677)
Decommissioning and used fuel management expenditures	(15)	(14)	(6)	(6)	(38)	(32)	(7)	(8)	(9)	(18)
Investment fund net withdrawals (deposits)	-	-	-	-	-	-	-	-	-	-
Change in long-term receivable	4	1	1	1	1	1	1	1	1	1
Cash used in investing activities	(342)	(401)	(333)	(267)	(338)	(313)	(265)	(288)	(284)	(694)
Financing Activities										
Debt retirements	(420)	(410)	(450)	(351)	(400)	(218)	(100)	(50)	-	-
Proceeds from issuance of long-term debt	470	360	500	250	350	150	-	-	-	100
Increase (decrease) in short-term indebtedness	(66)	120	(75)	(82)	(41)	(75)	(59)	(60)	(124)	205
Net Sinking fund installments / redemptions	9	(20)	18	107	10	44	(11)	(33)	(38)	(38)
Cash provided by (used in) financing activities	(7)	49	(7)	(76)	(81)	(99)	(169)	(143)	(162)	267
Net cash inflow (outflow)	(0)	0	0	0	(0)	(0)	0	(0)	(0)	0
Cash, beginning of year	1	1	1	1	1	1	1	1	1	1
Cash, end of year	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**	**1**

Figure 12: Change in Net Debt

Fiscal Year Ending March 31	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
(in millions $)										
Opening Net Debt	4,883	4,854	4,880	4,848	4,751	4,646	4,526	4,332	4,164	3,973
Ending Net Debt	4,854	4,880	4,848	4,751	4,646	4,526	4,332	4,164	3,973	4,208
Change in Net Debt	(29)	25	(32)	(96)	(105)	(120)	(194)	(168)	(191)	235
Reconcilation:										
Cash provided by operating activities	348	352	341	343	419	412	434	431	446	427
Cash used in investing activities	(342)	(401)	(333)	(267)	(338)	(313)	(265)	(288)	(284)	(694)
Sinking fund earnings	23	23	23	10	20	20	24	25	28	32
Foreign exchange adjustment on USD debt	0	1	1	10	4	2	-	-	-	-
Amortization of debt premiums / discounts	(1)	0	1	0	0	1	1	0	0	0
Cash available for net debt reduction	29	(25)	32	96	105	120	194	168	191	(235)

Appendix D – Statement of Financial Position

Figure 13: Forecasted Statement of Financial Position

Fiscal Year Ending March 31	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
(in millions $)										
Assets										
Current Assets										
Cash	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1	$ 1
Accounts receivable	254	258	259	265	270	275	281	286	292	298
Materials, supplies and fuel	164	168	174	178	181	185	189	192	196	200
Prepaid expenses	12	12	12	12	12	13	13	13	14	14
Current portion of long-term receivable	1	1	1	1	1	1	1	1	1	1
Total Current Assets	**431**	**439**	**447**	**456**	**466**	**475**	**484**	**494**	**504**	**514**
Non-Current Assets										
Land, building and equipment	6,164	6,559	6,891	7,160	7,468	7,758	8,026	8,319	8,610	9,316
Less: accumulated amortization	(1,789)	(2,055)	(2,332)	(2,624)	(2,916)	(3,213)	(3,517)	(3,820)	(4,125)	(4,439)
Property, plant and equipment	4,375	4,504	4,559	4,536	4,552	4,545	4,509	4,498	4,485	4,877
Intangible assets	27	22	15	15	14	14	13	13	13	12
Nuclear decommissioning and used fuel management funds	724	757	795	835	876	919	964	1,012	1,062	1,115
Long-term receivable	14	13	12	11	10	9	8	8	7	6
Sinking funds receivable	508	551	556	458	468	443	477	535	602	672
Other assets	2	2	2	2	2	2	2	2	2	2
Total Non-Current Assets	**5,651**	**5,850**	**5,940**	**5,857**	**5,923**	**5,932**	**5,975**	**6,068**	**6,170**	**6,683**
Total Assets	**6,082**	**6,289**	**6,387**	**6,313**	**6,388**	**6,407**	**6,459**	**6,562**	**6,674**	**7,197**
Regulatory assets	996	984	972	954	940	924	909	869	827	783
Total Assets and Regulatory Balances	**7,078**	**7,273**	**7,359**	**7,268**	**7,328**	**7,332**	**7,368**	**7,430**	**7,500**	**7,980**

Figure 13: Forecasted Statement of Financial Position (continued)

Fiscal Year Ending March 31	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
(in millions $)										
Current Liabilities										
Short term indebtedness	$ 892	$ 1,012	$ 937	$ 855	$ 813	$ 739	$ 680	$ 620	$ 496	$ 701
Accounts payable and accruals	258	273	238	193	198	202	207	212	218	223
Accrued interest	45	47	47	43	45	43	43	43	43	43
Current portion of long term debt	410	450	351	400	218	100	50	-	-	-
	1,606	1,782	1,573	1,490	1,274	1,084	980	875	756	967
Long-Term Debt										
Debentures	4,061	3,969	4,117	3,956	4,083	4,131	4,080	4,080	4,080	4,180
Deferred Liabilities										
Decommissioning and used nuclear fuel management liability	774	801	839	886	896	914	959	1,005	1,054	1,096
Post-employment benefits	137	136	136	136	136	135	135	135	135	135
Provisions for other liabilites and charges	64	67	69	66	73	73	74	74	74	74
	975	1,005	1,044	1,088	1,105	1,123	1,167	1,214	1,263	1,305
Shareholder's Equity										
Accumulated other comprehensive income	(94)	(91)	(90)	(88)	(87)	(85)	(84)	(82)	(80)	(77)
Retained earnings	531	608	715	822	952	1,079	1,223	1,343	1,481	1,605
	437	517	625	734	866	994	1,140	1,262	1,402	1,528
Total Liabilities & Shareholder's Equity	**$ 7,078**	**$ 7,273**	**$ 7,359**	**$ 7,268**	**$ 7,328**	**$ 7,332**	**$ 7,368**	**$ 7,430**	**$ 7,500**	**$ 7,980**

TAB 9

REFERENCE:

MIPUG/MH I-2h & k, Page 4 & 9 of 14

PREAMBLE TO IR (IF ANY):

QUESTION:

a) For Figure 1, for each entry, please provide the corresponding dollar value level of retained earnings needed to achieve the target at the specified targeted date.

b) For the IFF16 Update with Interim equity graph (page 9 of 14 of the response to MIPUG/MH-I-2k), please provide the graph in dollar values rather than percentages. Please also provide the annual values, specifically noting the portion represented by Retained Earnings, Unamortized Customer Contributions, AOCI, and other factors.

RATIONALE FOR QUESTION:

RESPONSE:

a) The table below provides the corresponding dollar value level of the retained earnings at the target year and also the retained earnings and fiscal year when the debt equity target is achieved.

Year	Consolidated Debt Equity Target	Consolidated Retained Earnings at Target Date	Consolidated Retained Earnings when Target Achieved	Fiscal Year when Target Achieved	Forecast
1995	75:25 debt equity ratio by 2005/06	$1.17B	$1.17B	2005/06	IFF96-1
2001	Achieve 75:25 debt equity ratio by 2005/06	$1.31B	$2.00B	2011/12	IFF02-1
2002	Achieve 75:25 debt equity ratio by 2011/12	$1.26B	n.a.	n.a.	IFF03-1
2005	Achieve 75:25 debt equity ratio by 2011/12	$2.11B	$3.35B	2016/17	IFF06-3
2009	Maintain a minimum debt equity ratio of 75:25	Target date not specified	$7.05B	2025/26	IFF10
2015	Achieve and maintain a minimum equity ratio of 25%	Target date not specified	$6.17B	2031/32	IFF15

n.a. = Not available. Target not achieved within 10 year forest period. 20 year forecasts were not produced prior to 2009.

b) The historical dollar values requested from 1962 to 1998 are not readily available and it is not known whether the calculation components during that period are comparable.

The following graph and table provide the requested equity dollar values for 1999 through 2036. Note that Manitoba Hydro's financial plan is focused on achieving a 25% equity capitalization level by the end of fiscal year 2026/27 (i.e. a 10 year plan). Projections beyond that have been provided but are forecast based on a simplifying assumption of 2% rate increases as a proxy for inflation. Proposed rate increase profiles for the subsequent decade are of limited value at this stage. Future rate trajectory - starting over 10 years from now - will necessarily be a function of an enhanced understanding of both the forecast accuracy of IFF16, the future growth and capital reinvestment expectations and an updated outlook for all of the other variables that affect Manitoba Hydro's financial results.

Figure 1

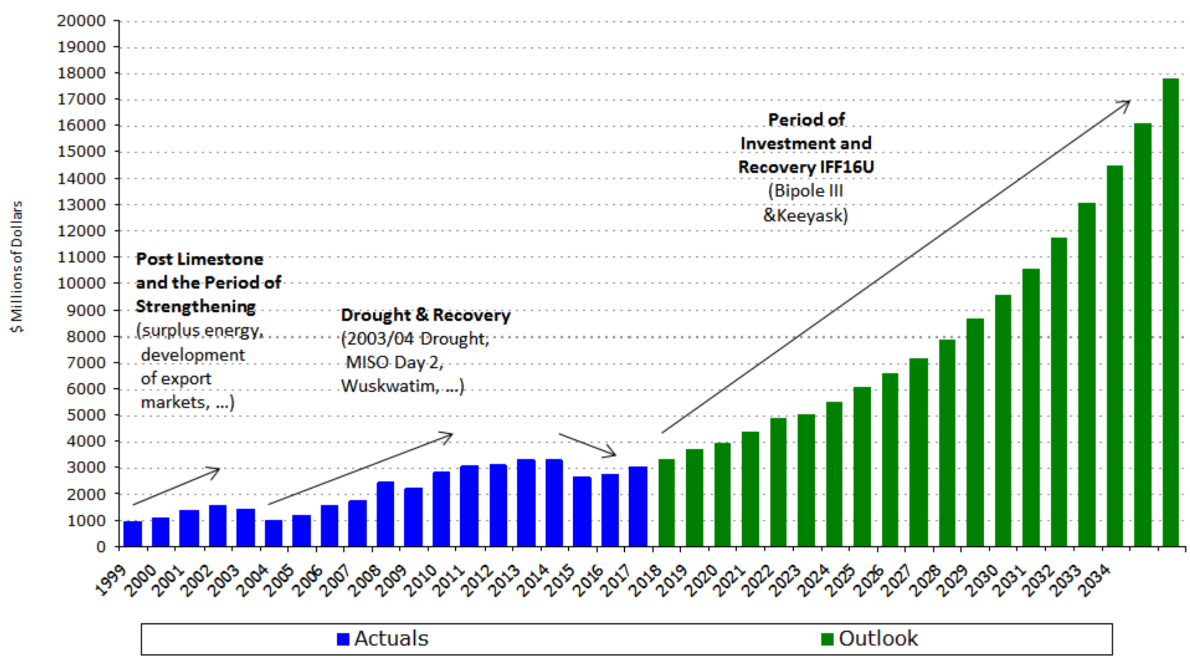


Figure 2

CONSOLIDATED EQUITY

	A	B	C	D	A+B+C+D
	Unamortized Customer Contributions	**Retained Earnings**	**AOCI**	**Non-Controlling Interest**	**Total Equity**
1999	267	666			933
2000	275	818			1 093
2001	281	1 088			1 369
2002	281	1 302			1 583
2003	264	1 170			1 434
2004	274	734			1 008
2005	296	870			1 166
2006	297	1 285			1 582
2007	298	1 407			1 705
2008	300	1 822	305		2 427
2009	296	2 076	(169)		2 203
2010	295	2 239	285		2 819
2011	295	2 389	367		3 051
2012	318	2 450	327		3 095
2013	340	2 542	299	95	3 276
2014	381	2 716	96	73	3 266
2015	457	2 779	(720)	120	2 636
2016	534	2 828	(776)	140	2 726
2017	651	2 899	(709)	170	3 011
2018	817	3 005	(699)	208	3 331
2019	844	3 230	(636)	257	3 696
2020	794	3 446	(580)	306	3 966
2021	736	3 805	(537)	346	4 350
2022	668	4 334	(497)	382	4 887
2023	600	4 780	(449)	87	5 018
2024	584	5 205	(377)	99	5 511
2025	595	5 748	(376)	102	6 069
2026	606	6 252	(375)	104	6 587
2027	618	6 844	(375)	108	7 194
2028	629	7 511	(375)	111	7 876
2029	640	8 284	(375)	107	8 656
2030	650	9 174	(375)	105	9 554
2031	661	10 180	(375)	103	10 569
2032	672	11 346	(375)	100	11 743
2033	684	12 645	(375)	99	13 052
2034	696	14 085	(375)	96	14 502
2035	708	15 683	(375)	94	16 111
2036	721	17 371	(375)	92	17 809

CONSOLIDATED DEBT

	E	F	G	H	I	J	E+F+G+H-I-J
	Long-Term Debt	Deferred Foreign Exchange	Current Portion of Long-Term Debt	Short-Term Debt	Sinking Fund Assets	Short-Term Investments	Total Debt
1999	5 883	-	-	240	1 111	57	4 955
2000	6 611	-	159	-	1 282	15	5 473
2001	6 968	(792)	496	190	1 350	(2)	5 514
2002	7 123	(809)	538	180	1 515	14	5 503
2003	6 925	(513)	343	128	948	30	5 905
2004	7 114	(166)	276	93	715	6	6 596
2005	7 048	45	156	59	562	9	6 737
2006	7 051	127	118	-	555	119	6 622
2007	6 822	149	405	148	630	1	6 893
2008	7 218		353	-	718	133	6 720
2009	7 668		519	100	666	170	7 451
2010	8 228		310	-	822	174	7 542
2011	8 617		30	-	282	70	8 295
2012	9 101		281	-	372	50	8 960
2013	9 329		656	-	352	32	9 601
2014	10 460		408	-	111	142	10 615
2015	12 303		377	-	114	494	12 072
2016	14 201		326	-	-	955	13 572
2017	16 102		336	-	-	646	15 792
2018	18 559		1 002	-	182	533	18 845
2019	21 773		349	-	400	631	21 091
2020	22 626		1 293	-	531	642	22 746
2021	23 441		1 366	-	501	690	23 617
2022	23 287		1 141	-	34	484	23 910
2023	24 142		290	-	92	670	23 669
2024	23 650		412	-	294	680	23 087
2025	22 937		715	-	210	1 007	22 435
2026	21 726		1 178	-	317	761	21 825
2027	22 178		150	-	328	865	21 135
2028	22 120		60	-	415	1 405	20 361
2029	19 683		2 440	-	593	2 032	19 497
2030	15 470		4 396	-	526	837	18 502
2031	16 300		2 173	-	224	827	17 421
2032	15 273		2 190	-	419	879	16 166
2033	15 529		908	-	581	1 082	14 774
2034	14 802		1 100	-	733	1 941	13 228
2035	14 471		265	-	911	2 223	11 601
2036	14 325		140	-	820	3 768	9 877

REFERENCE:

Appendix 4.1 Section 4.8.1

PREAMBLE TO IR (IF ANY):

KPMG States:
For Crown utilities such as Manitoba Hydro, in contrast, debt is either guaranteed by the Province or obtained through the province. Hence, in the event of financial distress, debt holders have a call on the resources of the Province and the provincial revenue base in seeking repayment of their debt, to remedy a default by the utility. This is a fundamental distinction and allows such Crown utilities to raise higher amounts of debt than would be consistent with a stand-alone, investor-owned utility.

Although Crown utilities may have access to a debt guarantee, one philosophy is that their financial targets should be set such that they have the same capital structure as a stand-alone, investor-owned, utility. Among other things, this would increase, relative to a more debt-intensive structure, the probability that the utility would remain self-supporting and would not impair the credit rating of its provincial shareholder. For Manitoba Hydro to reach the higher equity position that would be consistent with this approach, it would need to have higher rates for a period of time relative to those that would otherwise have been required. This reflects Manitoba Hydro's reliance on retained earnings for building its equity position.

QUESTION:

Please discuss whether it is Manitoba Hydro's expectation or goal to achieve a capital structure consistent with a stand-alone investor owned utility.

RATIONALE FOR QUESTION:

RESPONSE:

Manitoba Hydro does not have the goal of achieving a debt:equity capital structure consistent with that typically seen in a stand-alone investor owned utility. Manitoba Hydro observes that stand-alone investor owned utilities typically maintain equity levels that of 40%, significantly greater than Manitoba Hydro's equity target of 25%.

In Manitoba Hydro's view, achievement of a capital structure consistent with that of a typical stand-alone investor owned utility would be inconsistent with the regulatory framework that exists in Manitoba which, unlike many other jurisdictions, is not predicated on a rate of return construct.

Manitoba Hydro's financial targets are set in the context of being a government-owned entity with a modified cost of service rate regime. As such, targets are set based on a minimum level of financial strength that reasonably minimizes the risk of any contagion impact of the Corporation's financial profile on the credit rating and/or borrowing costs of the Province of Manitoba as well as ensuring Manitoba Hydro has the wherewithal to absorb adverse conditions (below average water conditions, rising interest rates) or event risks (asset failures) without imposing rate shock on customers.

Such wherewithal stems from appropriate levels of income, cash flow and reserves. As is noted, Manitoba Hydro's equity position can only be enhanced through net income and, as such, building an adequate equity position requires a multi-year plan. A strong equity capital position is the output of prudent financial planning, inclusive of rate setting, wherein Manitoba Hydro builds a base case plan with the objective of an appropriate level of net income and cash flow over a reasonable planning horizon. This is in particular critical in the early years of the current financial plan where the capacity to absorb risk is low due to current deficiencies in income and equity levels along with an unavoidable escalation in debt and operating costs as two major new projects are completed and commissioned.

REFERENCE:

PUB/MH I-42

PREAMBLE TO IR (IF ANY):

Manitoba Hydro states: “Manitoba Hydro does not have the goal of achieving a debt:equity capital structure consistent with that typically seen in a stand-alone investor owned utility. Manitoba Hydro observes that stand-alone investor owned utilities typically maintain equity levels that of 40%, significantly greater than Manitoba Hydro’s equity target of 25%.

In Manitoba Hydro’s view, achievement of a capital structure consistent with that of a typical stand-alone investor owned utility would be inconsistent with the regulatory framework that exists in Manitoba which, unlike many other jurisdictions, is not predicated on a rate of return construct.”

BCG also recommended that “[the 5-year] "workout program" would accelerate meeting 25% target equity from 2035 to 2024. Creates "surplus" equity position which can be used to maintain investment grade rating, issue government dividend and/or fund future capital projects”

Manitoba Hydro’s 20-year forecast based on Appendix 3.8 reflects an equity ratio exceeding 25% and achieving a ratio of 64% at the end of the 20-year forecast.

QUESTION:

a) Please explain what action MH plans on taking to address this trajectory which achieves an equity level well above the approved target and inconsistent with the regulatory framework in Manitoba.

b) Please provide an IFF with indicated rate changes to maintain a 75:25 debt to equity ratio throughout the 20-year forecast once achieved.

RATIONALE FOR QUESTION:

RESPONSE:

Manitoba Hydro's financial plan reflects a goal to return to its target 25% equity to capitalization ratio in 10 years. The focus of the Corporation's application is on the next 10 years of forecast financial results through 2026/27. 20 year financial forecasts have been provided in response to Minimum Filing Requirements and Information Requests. Manitoba Hydro ascribes limited value to forecasts a decade or more in the future given the potential for volatility in key assumptions many of which are beyond Manitoba Hydro's ability to accurately predict or control. The 20 year forecasts provided to date have essentially reflected a simplifying assumption that domestic rates and operating costs increase at 2% per annum as a proxy for inflation. PUB/MH II-28 provides some additional commentary on important limitations to the practical use of 20 year forecasts.

That said, the value to Manitoba Hydro's customers and the broader Manitoba economy from meeting Manitoba Hydro's 10 year target is apparent as discussed below as well as Coalition/MH II-19.

As compared to a plan to reach 25% equity by 2033/34 using even annual rate increases of 4.14% (Coalition/MH II-19), MH16 Update with Interim would leave forecast net debt $3.4 billion or 14% lower at the end of the 10 year period ending 2026/27. As a consequence, annual interest expense is reduced by $170 million in 2027/28 generating lower revenue requirement in 2027/28 and beyond.

With significantly less debt to service and a healthier financial condition, Manitoba Hydro and its regulator will have established the flexibility to consider future rate changes with a then much clearer understanding than is available today of load growth, export pricing, interest rates and reinvestment needs for the years beyond 2027.

As noted throughout this application, significantly higher levels of revenue from domestic rates are required in order to generate the income and cash flow necessary over the next 10 years to restore Manitoba Hydro's financial health. However, once the target debt/equity levels are reached, the necessity of the same level of income diminishes to a degree dependent on then estimates of future capital needs, growth expectations and interest rates. As noted above, a $3.4 billion reduction in net debt has a material consequent impact on revenue requirement. With a sound balance sheet, Manitoba Hydro and its regulator will be in a substantially preferred position to consider sub-inflationary rate increases or even rate decreases depending on the then understanding of business needs.

Due to the inherent uncertainty associated with attempting to forecast results in the 2028 to 2036 time frame, it is impossible to predict the measures Manitoba Hydro would propose to abate equity growth to unnecessary levels. However, should Manitoba Hydro find itself in a relatively stable operating environment but with significant capital investment needs on the near to intermediate term horizon, it is reasonable to expect the pace and extent of rate increases necessary to support major renewal and growth investments will be significantly abated by entering this period with a balance sheet and rate levels capable of absorbing incremental debt financing needs. In the alternative, without major expansion or other capital needs during or just beyond the 2028-2036 horizon, rate relief may be affordable and prudent.

The response to PUB/MH II-21b below offers an illustration of a potential outcome where rate changes are designed to keep the equity ratio at 25% each year in 2027/28 and thereafter. As can be seen, a substantial rate decrease of 19.8% is forecast for 2027/28. While Manitoba Hydro does not regard as prudent any financial plan that forecasts minimal or negative net income (as the scenario in part b) contemplates), the Corporation does note certain important conclusions with respect to ratepayer impacts. Coalition/MH II-6 provides further analysis.

The response to PUB/MH II-21b forecasts cumulative rate increases through 2033/34 of 38.8% after peaking (on a cumulative basis) at 77.4% in 2026/27. In a scenario of even annual rate increases of 4.14% to achieve an equity ratio of 25% by 2033/34 (Coalition/MH II-19), the cumulative rate increases amount to 97.7%. In other words, the cumulative rate increases in 2033/34 would be 60% less than under a more prolonged plan to address Manitoba Hydro's financial health. In absolute terms, for the average residential customer, electricity bills would be 30% lower in 2033/34 as compared to under the alternate plan of even annual rate increases of 4.14% over 16 years. Moreover, while Manitoba Hydro acknowledges its customers pay higher rates during the period of recovery, a residential customer using 1,000 kWh/month would experience lower bills over the period from 2017/18 to 2033/34, as shown in the table below.

	25% Equity Ratio Achieved	Cumulative Increase To 2026/27	Cumulative Increase To 2033/34	Average Monthly Bill - 2033/34	Cumulative Bills 2017/18 to 2033/34
PUB/MH II-21b Scenario based on MH16 - Update with Interim	2026/27	77.4%	38.8%	$121	$25,173
Coalition / MH II-19 Scenario even annual rate increases to 2033/34	2033/34	48.9%	97.7%	$172	$25,881
Difference			-60.3%	-29.9%	-2.7%

Customer interests and the long-run health of the economy of the Province of Manitoba are best served by a 10 year plan to reduce the Corporation's debt to more manageable levels. The IFF scenario presented in the response to part b) provides a powerful and plausible illustration of the importance of strong near-term action to address Manitoba Hydro's deteriorating financial condition. In doing so, Manitoba Hydro's customers enjoy both a substantially diminished risk of rate volatility and a significantly higher probability of lower rates beyond 2026/27 as compared to plans to address the Corporation's condition over 15 or 20 years. This advantage holds true regardless of eventual outcomes for key uncontrollable variables such as interest rates. This is illustrated in the following table comparing cumulative rates in 2033/34 under the Manitoba Hydro's 10-year plan to restore financial stability and an alternative 17-year plan.

	Cumulative Rate Increases in 2033/34	
	MH 10-Year Plan 25% Equity Ratio 2026/27	Alternative 17-Year Plan 25% Equity Ratio 2033/34
MH16 Update with Interim	38.75% (PUB/MH II-21b)	97.73% (Coalition/MH II-19)
Interest Rates + 50 basis points	42.08%	106.86%
Interest Rates + 100 basis points	45.81%	114.07%

In addition to the response to PUB/MH II-21b Manitoba Hydro offers two further alternative scenarios for consideration that are likely more plausible than a strict adherence to an exact target equity level once met. In the Alternative 1 (pages 11 to 16 of this response), even annual rate decreases of 5.7% are implemented in the three years from

2027/28 to 2029/30 in order to methodically reduce Manitoba Hydro's forecast net income to the range of $200 million per year. Manitoba Hydro reiterates its view that targeting $nil or negative net income as a planning matter is imprudent given the scale of the Corporation's business and assets and the potential for volatility in its results. While still targeting (for planning) a reasonable level of income, Manitoba Hydro notes that the cumulative annual rate increase by 2033/34 is 48.8% as compared to 97.7% under the "even annual increases to 2033/34" scenario (Coalition/MH II-19). This represents a 50% improvement over the "even annual rate increases" plan and, overall, 25% lower bills for residential customers as compared to the deferred alternative. Alternative 2 (pages 17 to 22 of this response) contemplates 0% rate increases in 2027/28 and every year after. Again, by 2033/34, cumulative rate increases of 77.4% under this scenario compare to 97.7% in the "even annual increases to 2033/34" scenario, a 21% improvement. Income levels and equity ratio growth in the second decade of the IFF are beyond what Manitoba Hydro would regard as needed absent an expectation of significant capital needs in the years beyond the 20 year horizon.

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
PUB/MH II-21b
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	-	37	179	315	458	619	789	973	1 094	1 158	1 224
BPIII Reserve Account	(96)	(151)	1	80	80	80	80	27	-	-	-
Extraprovincial	460	514	469	420	567	693	779	788	805	667	671
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 246	2 398	2 674	2 970	3 223	3 364	3 487	3 426	3 513
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Finance Expense	608	587	677	744	817	882	1 115	1 140	1 123	1 092	1 056
Finance Income	(17)	(17)	(21)	(28)	(35)	(34)	(39)	(18)	(24)	(27)	(21)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	131	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	132	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	119	132	145	154	161	165	174	175	175	175	176
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 655	2 392	2 507	2 822	2 893	2 904	2 887	2 889
Net Income before Net Movement in Reg. Deferral	(46)	13	96	(257)	283	463	401	470	582	540	625
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)	(50)	(49)	(45)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	209	208	354	526	443	423	533	491	580
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	93	211	205	349	518	434	411	530	489	577
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**93**	**211**	**205**	**349**	**518**	**434**	**411**	**530**	**489**	**577**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	209	208	354	526	443	423	533	491	580
* Additional Domestic Revenue											
Percent Increase		3.36%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	4.54%	2.00%	2.00%
Cumulative Percent Increase		3.36%	11.53%	20.34%	29.84%	40.10%	51.17%	63.11%	70.52%	73.93%	77.40%
Financial Ratios											
Equity	16%	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%
EBITDA Interest Coverage	1.51	1.54	1.71	1.72	1.84	2.01	2.03	2.08	2.22	2.24	2.36
Capital Coverage	1.53	1.40	1.48	1.47	1.88	2.34	2.25	2.37	2.34	2.20	2.29

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
PUB/MH II-21b
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	677	612	593	640	626	649	669	698	791
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	2 975	2 940	2 958	3 035	3 044	3 091	3 134	3 189	3 219
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 037	1 020	1 012	1 047	1 045	1 062	1 069	1 065	1 062
Finance Income	(21)	(18)	(16)	(16)	(17)	(18)	(20)	(19)	(17)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	177	177	178	179	180	181	182	183	189
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	2 901	2 920	2 947	3 018	3 030	3 081	3 124	3 164	3 191
Net Income before Net Movement in Reg. Deferral	73	20	11	17	13	10	9	25	29
Net Movement in Regulatory Deferral	(44)	(40)	(35)	(33)	(31)	(28)	(28)	(28)	(30)
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Net Income	30	(20)	(24)	(16)	(18)	(18)	(19)	(3)	(1)
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	26	(25)	(31)	(26)	(29)	(30)	(33)	(19)	(17)
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**26**	**(25)**	**(31)**	**(26)**	**(29)**	**(30)**	**(33)**	**(19)**	**(17)**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
	30	(20)	(24)	(16)	(18)	(18)	(19)	(3)	(1)
* Additional Domestic Revenue									
Percent Increase	-19.75%	-3.12%	-1.11%	1.81%	-1.05%	0.57%	0.40%	0.72%	3.26%
Cumulative Percent Increase	42.37%	37.92%	36.39%	38.86%	37.41%	38.19%	38.75%	39.74%	44.29%
Financial Ratios									
Equity	25%	25%	25%	25%	25%	25%	25%	25%	25%
EBITDA Interest Coverage	1.87	1.85	1.86	1.85	1.87	1.87	1.88	1.91	1.93
Capital Coverage	1.46	1.35	1.37	1.33	1.34	1.34	1.34	1.26	1.26

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
PUB/MH II-21b
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Current and Other Assets	1 773	1 915	2 269	2 498	2 569	1 943	1 773	1 989	2 230	2 086	2 199
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	21 272	24 305	27 127	28 452	30 060	30 123	30 194	30 360	30 542	30 350	30 423
Regulatory Deferral Balance	462	533	647	1 111	1 182	1 246	1 289	1 241	1 192	1 143	1 098
	21 733	24 839	27 774	29 563	31 243	31 369	31 483	31 601	31 734	31 493	31 522
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 189	22 994	22 850	23 674	23 173	22 485	21 223	21 666
Current and Other Liabilities	3 204	3 643	3 046	3 815	4 356	4 142	3 020	3 174	3 455	3 976	2 976
Provisions	70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	196	347	346	266	186	106	27	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	3 053	3 258	3 606	4 124	4 557	4 969	5 498	5 987	6 564
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(449)	(377)	(376)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 725	29 515	31 194	31 321	31 434	31 552	31 685	31 444	31 473
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 774	29 563	31 243	31 369	31 483	31 601	31 734	31 493	31 522
Net Debt	15 427	18 473	20 743	22 407	23 296	23 609	23 388	22 831	22 201	21 613	20 947
Total Equity	2 856	3 163	3 511	3 770	4 143	4 666	4 783	5 262	5 806	6 309	6 900
Equity Ratio	16%	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
PUB/MH II-21b
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
ASSETS									
Plant in Service	33 553	34 299	34 958	35 790	36 566	37 361	38 104	38 907	39 975
Accumulated Depreciation	(6 906)	(7 603)	(8 311)	(9 040)	(9 788)	(10 577)	(11 366)	(12 168)	(12 975)
Net Plant in Service	26 647	26 696	26 647	26 749	26 778	26 785	26 739	26 739	26 999
Construction in Progress	493	454	490	400	374	366	406	461	257
Current and Other Assets	2 200	2 225	2 254	2 131	2 398	2 442	2 794	3 048	3 806
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	30 380	30 376	30 353	30 204	30 435	30 440	30 749	31 021	31 799
Regulatory Deferral Balance	1 055	1 014	980	947	916	888	860	832	802
	31 434	31 391	31 333	31 151	31 352	31 328	31 609	31 852	32 600
LIABILITIES AND EQUITY									
Long-Term Debt	21 598	19 221	17 128	19 188	19 351	20 577	20 680	21 659	22 543
Current and Other Liabilities	2 920	5 271	7 329	5 103	5 160	3 932	4 133	3 405	3 276
Provisions	38	37	36	35	34	33	32	31	30
Deferred Revenue	615	624	634	644	654	665	676	687	699
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	6 590	6 564	6 533	6 507	6 478	6 448	6 415	6 396	6 379
Accumulated Other Comprehensive Income	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	31 385	31 342	31 284	31 102	31 303	31 279	31 560	31 804	32 552
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	31 434	31 391	31 333	31 151	31 352	31 328	31 609	31 852	32 600
Net Debt	20 821	20 762	20 691	20 637	20 573	20 508	20 435	20 407	20 380
Total Equity	6 940	6 921	6 897	6 879	6 858	6 836	6 812	6 802	6 795
Equity Ratio	25%	25%	25%	25%	25%	25%	25%	25%	25%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
PUB/MH II-21b
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 233	2 307	2 582	2 877	3 130	3 325	3 474	3 414	3 500
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(870)	(885)	(894)	(904)	(935)	(953)	(953)	(966)
Interest Paid	(553)	(531)	(635)	(700)	(762)	(834)	(1 063)	(1 112)	(1 101)	(1 072)	(1 037)
Interest Received	17	5	12	22	26	20	8	10	17	20	14
	810	734	767	759	961	1 169	1 171	1 287	1 437	1 408	1 512
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 160	2 190	990	1 160	(10)	(10)	(50)	590
Sinking Fund Withdrawals	146	0	0	120	318	813	182	46	337	138	232
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(240)	(249)	(253)	(245)	(242)
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 841	2 869	2 366	1 661	908	73	(28)	(507)	(342)	(877)	(603)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)	(756)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 749)	(3 059)	(2 438)	(1 850)	(1 477)	(997)	(796)	(800)	(814)	(838)
Net Increase (Decrease) in Cash	(309)	(145)	74	(18)	19	(236)	146	(16)	295	(283)	71
Cash at Beginning of Year	943	634	488	562	544	564	328	474	458	754	471
Cash at End of Year	634	488	562	544	564	328	474	458	754	471	541

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
PUB/MH II-21b
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES									
Cash Receipts from Customers	2 961	2 927	2 944	3 021	3 029	3 076	3 119	3 174	3 205
Cash Paid to Suppliers and Employees	(980)	(996)	(1 012)	(1 035)	(1 030)	(1 043)	(1 063)	(1 086)	(1 096)
Interest Paid	(1 019)	(1 014)	(1 011)	(1 036)	(1 027)	(1 052)	(1 060)	(1 069)	(1 073)
Interest Received	18	22	22	18	12	23	24	33	33
	980	939	943	967	985	1 004	1 021	1 052	1 069
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	(10)	(10)	2 370	4 190	2 350	2 140	1 160	1 300	970
Sinking Fund Withdrawals	150	60	310	542	0	230	36	10	275
Sinking Fund Payment	(237)	(239)	(243)	(240)	(228)	(239)	(239)	(250)	(262)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 173)	(2 190)	(908)	(1 100)	(265)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	(252)	(254)	(8)	91	(56)	(66)	44	(45)	714
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(767)	(798)	(793)	(832)	(840)	(857)	(870)	(948)	(966)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(847)	(873)	(864)	(905)	(913)	(928)	(940)	(1 016)	(1 033)
Net Increase (Decrease) in Cash	(119)	(187)	70	154	16	10	125	(8)	750
Cash at Beginning of Year	541	422	236	306	460	476	486	611	603
Cash at End of Year	422	236	306	460	476	486	611	603	1 353

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
Alternate 1: MH16 Update with Interim with 5.70% Rate Decrease from 2028-2030
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	-	37	179	315	458	619	789	973	1 094	1 158	1 224
BPIII Reserve Account	(96)	(151)	1	80	80	80	80	27	-	-	-
Extraprovincial	460	514	469	420	567	693	779	788	805	667	671
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 246	2 398	2 674	2 970	3 223	3 364	3 487	3 426	3 513
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Finance Expense	608	587	677	744	817	882	1 115	1 140	1 123	1 092	1 056
Finance Income	(17)	(17)	(21)	(28)	(35)	(34)	(39)	(18)	(24)	(27)	(21)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	131	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	132	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	119	132	145	154	161	165	174	175	175	175	176
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 655	2 392	2 507	2 822	2 893	2 904	2 887	2 889
Net Income before Net Movement in Reg. Deferral	(46)	13	96	(257)	283	463	401	470	582	540	625
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)	(50)	(49)	(45)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	209	208	354	526	443	423	533	491	580
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	93	211	205	349	518	434	411	530	489	577
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**93**	**211**	**205**	**349**	**518**	**434**	**411**	**530**	**489**	**577**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	209	208	354	526	443	423	533	491	580
* Additional Domestic Revenue											
Percent Increase		3.36%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	4.54%	2.00%	2.00%
Cumulative Percent Increase		3.36%	11.53%	20.34%	29.84%	40.10%	51.17%	63.11%	70.52%	73.93%	77.40%
Financial Ratios											
Equity	16%	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%
EBITDA Interest Coverage	1.51	1.54	1.71	1.72	1.84	2.01	2.03	2.08	2.22	2.24	2.36
Capital Coverage	1.53	1.40	1.48	1.47	1.88	2.34	2.25	2.37	2.34	2.20	2.29

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
Alternate 1: MH16 Update with Interim with 5.70% Rate Decrease from 2028-2030
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	1 075	932	794	803	815	829	842	856	870
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 373	3 260	3 159	3 197	3 233	3 270	3 307	3 347	3 299
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 037	1 020	995	990	977	979	975	958	945
Finance Income	(26)	(34)	(29)	(16)	(17)	(17)	(21)	(20)	(20)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	177	177	178	179	180	181	182	183	189
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	2 896	2 904	2 917	2 962	2 962	2 999	3 029	3 056	3 071
Net Income before Net Movement in Reg. Deferral	477	356	242	236	271	271	277	291	228
Net Movement in Regulatory Deferral	(44)	(40)	(35)	(33)	(31)	(28)	(28)	(28)	(30)
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Net Income	433	316	208	203	240	244	249	263	198
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	429	311	200	193	229	231	235	247	182
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**429**	**311**	**200**	**193**	**229**	**231**	**235**	**247**	**182**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
	433	316	208	203	240	244	249	263	198
* Additional Domestic Revenue									
Percent Increase	-5.70%	-5.70%	-5.70%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Cumulative Percent Increase	67.29%	57.75%	48.75%	48.75%	48.75%	48.75%	48.75%	48.75%	48.75%
Financial Ratios									
Equity	26%	28%	29%	29%	30%	31%	32%	33%	34%
EBITDA Interest Coverage	2.27	2.19	2.12	2.12	2.19	2.21	2.24	2.29	2.26
Capital Coverage	2.06	1.83	1.70	1.63	1.69	1.68	1.70	1.57	1.49

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
Alternate 1: MH16 Update with Interim with 5.70% Rate Decrease from 2028-2030
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Current and Other Assets	1 773	1 915	2 269	2 498	2 569	1 943	1 773	1 989	2 230	2 086	2 199
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	21 272	24 305	27 127	28 452	30 060	30 123	30 194	30 360	30 542	30 350	30 423
Regulatory Deferral Balance	462	533	647	1 111	1 182	1 246	1 289	1 241	1 192	1 143	1 098
	21 733	24 839	27 774	29 563	31 243	31 369	31 483	31 601	31 734	31 493	31 522
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 189	22 994	22 850	23 674	23 173	22 485	21 223	21 666
Current and Other Liabilities	3 204	3 643	3 046	3 815	4 356	4 142	3 020	3 174	3 455	3 976	2 976
Provisions	70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	196	347	346	266	186	106	27	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	3 053	3 258	3 606	4 124	4 557	4 969	5 498	5 987	6 564
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(449)	(377)	(376)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 725	29 515	31 194	31 321	31 434	31 552	31 685	31 444	31 473
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 774	29 563	31 243	31 369	31 483	31 601	31 734	31 493	31 522
Net Debt	15 427	18 473	20 743	22 407	23 296	23 609	23 388	22 831	22 201	21 613	20 947
Total Equity	2 856	3 163	3 511	3 770	4 143	4 666	4 783	5 262	5 806	6 309	6 900
Equity Ratio	16%	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
Alternate 1: MH16 Update with Interim with 5.70% Rate Decrease from 2028-2030
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
ASSETS									
Plant in Service	33 553	34 299	34 958	35 790	36 566	37 361	38 104	38 907	39 975
Accumulated Depreciation	(6 906)	(7 603)	(8 311)	(9 040)	(9 788)	(10 577)	(11 366)	(12 168)	(12 975)
Net Plant in Service	26 647	26 696	26 647	26 749	26 778	26 785	26 739	26 739	26 999
Construction in Progress	493	454	490	400	374	366	406	461	257
Current and Other Assets	2 603	2 964	2 221	2 114	2 436	2 336	2 956	3 072	4 029
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	30 783	31 115	30 321	30 187	30 473	30 334	30 911	31 045	32 021
Regulatory Deferral Balance	1 055	1 014	980	947	916	888	860	832	802
	31 837	32 130	31 300	31 134	31 389	31 222	31 771	31 876	32 823
LIABILITIES AND EQUITY									
Long-Term Debt	21 598	19 221	16 128	17 988	17 951	18 777	18 880	19 459	20 343
Current and Other Liabilities	2 920	5 271	7 326	5 097	5 150	3 918	4 118	3 387	3 256
Provisions	38	37	36	35	34	33	32	31	30
Deferred Revenue	615	624	634	644	654	665	676	687	699
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	6 993	7 303	7 503	7 697	7 926	8 156	8 392	8 639	8 821
Accumulated Other Comprehensive Income	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	31 788	32 081	31 252	31 085	31 340	31 174	31 722	31 827	32 774
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	31 837	32 130	31 300	31 134	31 389	31 222	31 771	31 876	32 823
Net Debt	20 418	20 023	19 724	19 454	19 136	18 814	18 473	18 183	17 957
Total Equity	7 343	7 660	7 867	8 068	8 305	8 545	8 788	9 045	9 237
Equity Ratio	26%	28%	29%	29%	30%	31%	32%	33%	34%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
Alternate 1: MH16 Update with Interim with 5.70% Rate Decrease from 2028-2030
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 233	2 307	2 582	2 877	3 130	3 325	3 474	3 414	3 500
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(870)	(885)	(894)	(904)	(935)	(953)	(953)	(966)
Interest Paid	(553)	(531)	(635)	(700)	(762)	(834)	(1 063)	(1 112)	(1 101)	(1 072)	(1 037)
Interest Received	17	5	12	22	26	20	8	10	17	20	14
	810	734	767	759	961	1 169	1 171	1 287	1 437	1 408	1 512
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 160	2 190	990	1 160	(10)	(10)	(50)	590
Sinking Fund Withdrawals	146	0	0	120	318	813	182	46	337	138	232
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(240)	(249)	(253)	(245)	(242)
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 841	2 869	2 366	1 661	908	73	(28)	(507)	(342)	(877)	(603)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)	(756)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 749)	(3 059)	(2 438)	(1 850)	(1 477)	(997)	(796)	(800)	(814)	(838)
Net Increase (Decrease) in Cash	(309)	(145)	74	(18)	19	(236)	146	(16)	295	(283)	71
Cash at Beginning of Year	943	634	488	562	544	564	328	474	458	754	471
Cash at End of Year	634	488	562	544	564	328	474	458	754	471	541

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
Alternate 1: MH16 Update with Interim with 5.70% Rate Decrease from 2028-2030
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
OPERATING ACTIVITIES									
Cash Receipts from Customers	3 360	3 247	3 146	3 183	3 219	3 256	3 292	3 333	3 284
Cash Paid to Suppliers and Employees	(980)	(996)	(1 012)	(1 035)	(1 030)	(1 043)	(1 063)	(1 086)	(1 096)
Interest Paid	(1 019)	(1 014)	(997)	(983)	(962)	(973)	(965)	(965)	(955)
Interest Received	23	39	36	17	13	21	25	32	34
	1 383	1 275	1 172	1 183	1 239	1 261	1 289	1 314	1 268
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	(10)	(10)	1 370	3 990	2 150	1 740	1 160	900	970
Sinking Fund Withdrawals	150	60	310	532	0	230	36	10	271
Sinking Fund Payment	(237)	(239)	(243)	(230)	(216)	(225)	(221)	(230)	(237)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 173)	(2 190)	(908)	(1 100)	(265)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	(252)	(254)	(1 008)	(109)	(244)	(451)	63	(425)	734
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(767)	(798)	(793)	(832)	(840)	(857)	(870)	(948)	(966)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(847)	(873)	(864)	(905)	(913)	(928)	(940)	(1 016)	(1 033)
Net Increase (Decrease) in Cash	284	149	(701)	170	82	(119)	412	(127)	969
Cash at Beginning of Year	541	826	975	274	443	525	407	818	691
Cash at End of Year	826	975	274	443	525	407	818	691	1 661

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
Alternate 2: MH16 Update with Interim with 0% Rate Increase from 2028 On
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
REVENUES											
Domestic Revenue											
at approved rates	1 515	1 578	1 565	1 551	1 537	1 544	1 542	1 542	1 553	1 567	1 583
additional*	-	37	179	315	458	619	789	973	1 094	1 158	1 224
BPIII Reserve Account	(96)	(151)	1	80	80	80	80	27	-	-	-
Extraprovincial	460	514	469	420	567	693	779	788	805	667	671
Other	28	30	31	31	33	33	34	34	35	35	36
	1 907	2 008	2 246	2 398	2 674	2 970	3 223	3 364	3 487	3 426	3 513
EXPENSES											
Operating and Administrative	536	518	501	511	513	524	536	548	559	571	583
Finance Expense	608	587	677	744	817	882	1 115	1 140	1 123	1 092	1 056
Finance Income	(17)	(17)	(21)	(28)	(35)	(34)	(39)	(18)	(24)	(27)	(21)
Depreciation and Amortization	375	396	471	515	555	597	689	714	726	739	752
Water Rentals and Assessments	131	130	120	110	113	117	127	128	131	131	131
Fuel and Power Purchased	132	124	140	158	165	156	140	135	138	127	129
Capital and Other Taxes	119	132	145	154	161	165	174	175	175	175	176
Other Expenses	60	116	109	481	94	92	71	64	67	71	76
Corporate Allocation	8	8	8	8	8	8	8	8	8	8	8
	1 952	1 995	2 150	2 655	2 392	2 507	2 822	2 893	2 904	2 887	2 889
Net Income before Net Movement in Reg. Deferral	(46)	13	96	(257)	283	463	401	470	582	540	625
Net Movement in Regulatory Deferral	66	72	114	464	71	64	43	(48)	(50)	(49)	(45)
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Net Income	41	85	209	208	354	526	443	423	533	491	580
Net Income Attributable to:											
Manitoba Hydro before Non-recurring Item	33	93	211	205	349	518	434	411	530	489	577
Non-recurring Gain	20	-	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**53**	**93**	**211**	**205**	**349**	**518**	**434**	**411**	**530**	**489**	**577**
Non-controlling Interest	(12)	(8)	(1)	2	5	9	10	11	3	2	3
	41	85	209	208	354	526	443	423	533	491	580
* Additional Domestic Revenue											
Percent Increase		3.36%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	4.54%	2.00%	2.00%
Cumulative Percent Increase		3.36%	11.53%	20.34%	29.84%	40.10%	51.17%	63.11%	70.52%	73.93%	77.40%
Financial Ratios											
Equity	16%	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%
EBITDA Interest Coverage	1.51	1.54	1.71	1.72	1.84	2.01	2.03	2.08	2.22	2.24	2.36
Capital Coverage	1.53	1.40	1.48	1.47	1.88	2.34	2.25	2.37	2.34	2.20	2.29

ELECTRIC OPERATIONS
PROJECTED OPERATING STATEMENT
Alternate 2: MH16 Update with Interim with 0% Rate Increase from 2028 On
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
REVENUES									
Domestic Revenue									
at approved rates	1 599	1 614	1 630	1 647	1 673	1 701	1 729	1 757	1 786
additional*	1 237	1 249	1 261	1 274	1 295	1 316	1 337	1 359	1 381
BPIII Reserve Account	-	-	-	-	-	-	-	-	-
Extraprovincial	662	677	697	709	705	701	696	694	602
Other	36	37	38	38	39	40	40	40	41
	3 535	3 577	3 626	3 669	3 712	3 757	3 802	3 850	3 810
EXPENSES									
Operating and Administrative	595	607	620	633	646	660	674	688	702
Finance Expense	1 037	1 020	994	929	888	859	824	778	731
Finance Income	(28)	(43)	(49)	(16)	(19)	(18)	(24)	(24)	(27)
Depreciation and Amortization	765	776	790	805	822	840	857	872	888
Water Rentals and Assessments	132	132	132	133	133	133	134	134	134
Fuel and Power Purchased	131	134	138	147	129	128	134	143	133
Capital and Other Taxes	177	177	178	179	180	181	182	183	189
Other Expenses	79	84	87	87	89	91	92	95	96
Corporate Allocation	8	8	5	3	3	3	3	3	3
	2 894	2 895	2 896	2 900	2 872	2 877	2 876	2 871	2 850
Net Income before Net Movement in Reg. Deferral	640	682	730	769	841	880	926	979	960
Net Movement in Regulatory Deferral	(44)	(40)	(35)	(33)	(31)	(28)	(28)	(28)	(30)
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Net Income	597	642	696	736	810	853	898	950	930
Net Income Attributable to:									
Manitoba Hydro before Non-recurring Item	593	637	688	727	799	840	884	935	914
Non-recurring Gain	-	-	-	-	-	-	-	-	-
Manitoba Hydro	**593**	**637**	**688**	**727**	**799**	**840**	**884**	**935**	**914**
Non-controlling Interest	4	5	8	10	11	13	14	15	16
	597	642	696	736	810	853	898	950	930
* Additional Domestic Revenue									
Percent Increase	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Cumulative Percent Increase	77.40%	77.40%	77.40%	77.40%	77.40%	77.40%	77.40%	77.40%	77.40%
Financial Ratios									
Equity	27%	29%	32%	35%	38%	41%	44%	48%	51%
EBITDA Interest Coverage	2.43	2.52	2.65	2.76	2.95	3.09	3.27	3.48	3.64
Capital Coverage	2.31	2.30	2.41	2.36	2.46	2.49	2.54	2.39	2.35

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
Alternate 2: MH16 Update with Interim with 0% Rate Increase from 2028 On
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
ASSETS											
Plant in Service	13 065	13 679	19 062	19 684	20 747	26 168	30 504	31 034	31 670	32 334	32 945
Accumulated Depreciation	(972)	(1 301)	(1 731)	(2 178)	(2 616)	(3 125)	(3 705)	(4 328)	(4 942)	(5 607)	(6 212)
Net Plant in Service	12 093	12 378	17 332	17 506	18 131	23 043	26 799	26 706	26 727	26 727	26 732
Construction in Progress	7 079	9 471	6 745	7 522	8 012	3 836	367	454	418	414	411
Current and Other Assets	1 773	1 915	2 269	2 498	2 569	1 943	1 773	1 989	2 230	2 086	2 199
Goodwill and Intangible Assets	327	541	782	926	1 348	1 302	1 256	1 211	1 167	1 123	1 081
Total Assets before Regulatory Deferral	21 272	24 305	27 127	28 452	30 060	30 123	30 194	30 360	30 542	30 350	30 423
Regulatory Deferral Balance	462	533	647	1 111	1 182	1 246	1 289	1 241	1 192	1 143	1 098
	21 733	24 839	27 774	29 563	31 243	31 369	31 483	31 601	31 734	31 493	31 522
LIABILITIES AND EQUITY											
Long-Term Debt	15 725	18 141	21 376	22 189	22 994	22 850	23 674	23 173	22 485	21 223	21 666
Current and Other Liabilities	3 204	3 643	3 046	3 815	4 356	4 142	3 020	3 174	3 455	3 976	2 976
Provisions	70	50	49	48	46	45	43	42	41	40	39
Deferred Revenue	450	465	491	520	542	551	561	571	582	593	603
BPIII Reserve Account	196	347	346	266	186	106	27	(0)	(0)	(0)	(0)
Retained Earnings	2 749	2 842	3 053	3 258	3 606	4 124	4 557	4 969	5 498	5 987	6 564
Accumulated Other Comprehensive Income	(709)	(699)	(636)	(580)	(537)	(497)	(449)	(377)	(376)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	21 684	24 790	27 725	29 515	31 194	31 321	31 434	31 552	31 685	31 444	31 473
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49	49	49
	21 733	24 839	27 774	29 563	31 243	31 369	31 483	31 601	31 734	31 493	31 522
Net Debt	15 427	18 473	20 743	22 407	23 296	23 609	23 388	22 831	22 201	21 613	20 947
Total Equity	2 856	3 163	3 511	3 770	4 143	4 666	4 783	5 262	5 806	6 309	6 900
Equity Ratio	16%	15%	14%	14%	15%	17%	17%	19%	21%	23%	25%

ELECTRIC OPERATIONS
PROJECTED BALANCE SHEET
Alternate 2: MH16 Update with Interim with 0% Rate Increase from 2028 On
(In Millions of Dollars)

For the year ended March 31	2028	2029	2030	2031	2032	2033	2034	2035	2036
ASSETS									
Plant in Service	33 553	34 299	34 958	35 790	36 566	37 361	38 104	38 907	39 975
Accumulated Depreciation	(6 906)	(7 603)	(8 311)	(9 040)	(9 788)	(10 577)	(11 366)	(12 168)	(12 975)
Net Plant in Service	26 647	26 696	26 647	26 749	26 778	26 785	26 739	26 739	26 999
Construction in Progress	493	454	490	400	374	366	406	461	257
Current and Other Assets	2 767	3 454	2 198	2 021	2 313	2 418	3 283	3 478	4 164
Goodwill and Intangible Assets	1 040	1 001	962	924	885	848	810	773	736
Total Assets before Regulatory Deferral	30 946	31 605	30 298	30 094	30 350	30 416	31 238	31 450	32 156
Regulatory Deferral Balance	1 055	1 014	980	947	916	888	860	832	802
	32 001	32 619	31 277	31 041	31 266	31 304	32 098	32 282	32 958
LIABILITIES AND EQUITY									
Long-Term Debt	21 598	19 221	15 128	16 388	15 751	16 177	15 880	15 859	15 743
Current and Other Liabilities	2 920	5 271	7 325	5 093	5 146	3 910	4 107	3 366	3 234
Provisions	38	37	36	35	34	33	32	31	30
Deferred Revenue	615	624	634	644	654	665	676	687	699
BPIII Reserve Account	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
Retained Earnings	7 156	7 793	8 481	9 208	10 006	10 846	11 729	12 664	13 578
Accumulated Other Comprehensive Income	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)	(375)
Total Liabilities and Equity before Regulatory Deferral	31 952	32 571	31 229	30 993	31 217	31 255	32 049	32 233	32 909
Regulatory Deferral Balance	49	49	49	49	49	49	49	49	49
	32 001	32 619	31 277	31 041	31 266	31 304	32 098	32 282	32 958
Net Debt	20 254	19 533	18 747	17 946	17 059	16 132	15 146	14 178	13 222
Total Equity	7 507	8 149	8 845	9 579	10 386	11 234	12 126	13 071	13 995
Equity Ratio	27%	29%	32%	35%	38%	41%	44%	48%	51%

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
Alternate 2: MH16 Update with Interim with 0% Rate Increase from 2028 On
(In Millions of Dollars)

For the year ended March 31	ACTUAL 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
OPERATING ACTIVITIES											
Cash Receipts from Customers	1 901	2 152	2 233	2 307	2 582	2 877	3 130	3 325	3 474	3 414	3 500
Cash Paid to Suppliers and Employees	(555)	(892)	(843)	(870)	(885)	(894)	(904)	(935)	(953)	(953)	(966)
Interest Paid	(553)	(531)	(635)	(700)	(762)	(834)	(1 063)	(1 112)	(1 101)	(1 072)	(1 037)
Interest Received	17	5	12	22	26	20	8	10	17	20	14
	810	734	767	759	961	1 169	1 171	1 287	1 437	1 408	1 512
FINANCING ACTIVITIES											
Proceeds from Long-Term Debt	2 166	3 468	3 600	2 160	2 190	990	1 160	(10)	(10)	(50)	590
Sinking Fund Withdrawals	146	0	0	120	318	813	182	46	337	138	232
Sinking Fund Payment	(146)	(182)	(222)	(260)	(296)	(353)	(240)	(249)	(253)	(245)	(242)
Retirement of Long-Term Debt	(320)	(407)	(1 002)	(349)	(1 293)	(1 366)	(1 141)	(290)	(412)	(715)	(1 178)
Other	(5)	(10)	(10)	(11)	(11)	(11)	11	(5)	(5)	(5)	(5)
	1 841	2 869	2 366	1 661	908	73	(28)	(507)	(342)	(877)	(603)
INVESTING ACTIVITIES											
Property, Plant and Equipment, net of contributions	(2 925)	(3 660)	(3 002)	(2 391)	(1 760)	(1 368)	(898)	(700)	(704)	(732)	(756)
Other	(35)	(89)	(57)	(46)	(89)	(109)	(99)	(96)	(96)	(82)	(81)
	(2 960)	(3 749)	(3 059)	(2 438)	(1 850)	(1 477)	(997)	(796)	(800)	(814)	(838)
Net Increase (Decrease) in Cash	(309)	(145)	74	(18)	19	(236)	146	(16)	295	(283)	71
Cash at Beginning of Year	943	634	488	562	544	564	328	474	458	754	471
Cash at End of Year	634	488	562	544	564	328	474	458	754	471	541

ELECTRIC OPERATIONS
PROJECTED CASH FLOW STATEMENT
Alternate 2: MH16 Update with Interim with 0% Rate Increase from 2028 On
(In Millions of Dollars)

For the year ended March 31	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
OPERATING ACTIVITIES									
Cash Receipts from Customers	3 521	3 564	3 612	3 655	3 698	3 743	3 787	3 836	3 796
Cash Paid to Suppliers and Employees	(980)	(996)	(1 012)	(1 035)	(1 030)	(1 043)	(1 063)	(1 087)	(1 096)
Interest Paid	(1 019)	(1 014)	(997)	(925)	(873)	(856)	(817)	(792)	(741)
Interest Received	25	48	55	18	14	22	26	35	39
	1 547	1 601	1 659	1 713	1 809	1 865	1 934	1 993	1 998
FINANCING ACTIVITIES									
Proceeds from Long-Term Debt	(10)	(10)	370	3 390	1 550	1 340	760	300	(30)
Sinking Fund Withdrawals	150	60	310	523	0	230	0	10	210
Sinking Fund Payment	(237)	(239)	(243)	(220)	(201)	(202)	(193)	(199)	(199)
Retirement of Long-Term Debt	(150)	(60)	(2 440)	(4 396)	(2 173)	(2 190)	(908)	(1 100)	(265)
Other	(5)	(5)	(5)	(5)	(5)	(7)	(4)	(4)	(5)
	(252)	(254)	(2 008)	(709)	(829)	(829)	(345)	(994)	(288)
INVESTING ACTIVITIES									
Property, Plant and Equipment, net of contributions	(767)	(798)	(793)	(832)	(840)	(857)	(870)	(948)	(966)
Other	(80)	(74)	(72)	(73)	(72)	(71)	(70)	(68)	(67)
	(847)	(873)	(864)	(905)	(913)	(928)	(940)	(1 016)	(1 033)
Net Increase (Decrease) in Cash	448	475	(1 214)	100	67	108	649	(17)	676
Cash at Beginning of Year	541	989	1 464	250	350	417	525	1 174	1 158
Cash at End of Year	989	1 464	250	350	417	525	1 174	1 158	1 834

REFERENCE:

Coalition/MH I-96(d)

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide versions of PUB MFR 55 & 56 based on Appendix 3.4 and Appendix 3.7 scenario 3 and provide commentary on changes in finance expense and assumed debt retirements with that provided in response to Coalition/MH I-96 (d).

RATIONALE FOR QUESTION:

RESPONSE:

As noted in the response to PUB/MH II-21, Manitoba Hydro's financial plan reflects a goal to return to its target 25% equity to capitalization ratio in 10 years. The focus of the Corporation's application is on the next 10 years of forecast financial results through 2026/27. 20 year financial forecasts have been provided in response to Minimum Filing Requirements and Information Requests such as herein. The 20 year forecasts provided to date have essentially reflected a simplifying assumption that domestic rates and operating costs increase at 2% per annum as a proxy for inflation. Manitoba Hydro believes limited value should be ascribed to forecasts a decade or more in the future. The potential for volatility in key assumptions, many of which are beyond Manitoba Hydro's ability to control, reduces the second half of a 20 year forecast to little more than a hypothetical modeling exercise. Manitoba Hydro spoke to the issues of such long-range forecasting in its response to Coalition/MH I-15. Moreover, as noted in PUB/MH II-21 and Coalition/MH II-6, proposed rate trajectories more than a decade from today will be a function of the then existent conditions and outlook for the Corporation and could be materially different than the inflationary rate increases assumed in the latter half of MH16 Update with Interim. The value of addressing Manitoba Hydro's unsustainable debt load proactively is the flexibility to provide more stable and, on a relative basis, lower rates in the long term regardless of unknowable future circumstances up to 20 years from now.

The scenario comparisons requested rely on debt levels and interest expense driven by a modeling exercise that sees Manitoba Hydro's equity ratio reaching 64% by 2036. The value of this analysis is limited given, as noted in PUB/MH I-42; Manitoba Hydro does not hold such equity levels as goals. The analysis does underscore the quantum of benefit from having taken steps to restore financial health over the next 10 years but Manitoba Hydro is not advocating using such forecast flexibility, should it come to pass, to over-capitalize its balance sheet. As Manitoba Hydro begins making progress toward its 10 year goal of a 25% equity level and its outlook for the years beyond 2026/27 clarifies, it will turn its attention to the appropriate rate strategy for the 2030s.

The following is a table comparing the change in long term debt levels in the period of 2024 to 2036 between Appendix 3.4 (IFF16 with IFF15 level rate increases) and MH16 Update with Interim (provided in Coalition/MH I-96 (d)).

Long Term Debt Comparison
Period 2024-2036
(in $ millions Canadian Dollars)

	2024 Opening LTD Balance	LTD Proceeds	LTD Maturities	2036 Closing LTD Balance	Debt Retirement
Appendix 3.4	25,049	14,450	17,622	21,914	3,135
IFF16 Update with Interim	24,433	6,250	16,549	14,099	10,334
Increase/ (Decrease)	616	8,200	1,073	7,815	(7,199)

At the beginning of fiscal year 2024, the long term debt balances in both scenarios are quite similar with the benefit of higher rate increases under MH16 Update with Interim reducing forecast debt in 2024 as compared to Appendix 3.4. Cash flow from higher rates more than offsets debt growth that is a consequence of a deteriorated outlook for load growth and export price appreciation under MH16 Update with Interim as compared to the assumptions in the Appendix 3.4 scenario. However, the lower rate increases in the Appendix 3.4 scenario generate a cash requirement to borrow an additional $8.2 billion of long term debt after 2024 to refinance maturing long term debt (Increase in LTD Proceeds). The compounding effect of higher rate increases in MH16 Update with Interim results in additional cash that can be made available for debt retirement. Assuming this cash is used for debt retirement, MH16 Update with Interim will retire approximately $10.3 billion of long term debt during the period of 2024 to 2036 (2024 Opening LTD Balance - 2036 Closing

LTD Balance). The Appendix 3.4 scenario will retire only $3.1 billion of debt during this period. IFF15 level rate increases result in a significant decrease in the amount of debt retirement as compared to MH16 Update with Interim (approximately $7.2 billion less).

The following is a table comparing the change in long term debt levels in the period of 2024 to 2036 between Appendix 3.7 (MH16 Update with Interim with 7.90% for 2019-2022 and 2% thereafter) and MH16 Update with Interim.

Long Term Debt Comparison
Period 2024-2036
(in $ millions Canadian Dollars)

	2024 Opening LTD Balance	LTD Proceeds	LTD Maturities	2036 Closing LTD Balance	Debt Retirement
Appendix 3.7 Scenario 3	24,628	12,650	16,767	20,466	4,162
IFF16 Update with Interim	24,433	6,250	16,549	14,099	10,334
Increase/ (Decrease)	195	6,400	218	6,367	(6,172)

At the beginning of fiscal year 2024, the long term debt balances in both scenarios are quite similar due to the limited differences in rate increase profile between 2018 and 2024. However, the compounding effect of lower rate increases in the Appendix 3.7 scenario 3 in the 2023-2025 time frame generate a cash requirement to borrow an additional $6.4 billion of long term debt to refinance maturing long term debt (Increase in LTD Proceeds). The compounding effect of higher rate increases in MH16 Update with Interim results in additional cash that can be made available for debt retirement. Assuming this cash is used for debt retirement, MH16 Update with Interim will retire approximately $10.3 billion of long term debt during the period of 2024 to 2036 (2024 Opening LTD Balance - 2036 Closing LTD Balance). The Appendix 3.7 scenario 3 will retire only $4.1 billion of debt during this period. In order to meet the debt/equity target in a 10 year timeframe, MH16 Update with Interim required additional rate increases of 7.90% in 2023 and 2024 and a 4.54% rate increase in 2025 to make up for the loss of compounding resulting from the lower interim rate increase granted of 3.36% versus the requested 7.90% in 2018. The loss of rate increase compounding in the Appendix 3.7 scenario 3 results in a significant decrease in the amount of debt retirement as compared to MH16 Update with Interim (approximately $6.2 billion less). The impact of the lower interim rate increase of 3.36% is quite significant and highlights the importance of Manitoba Hydro securing its requested rate increases in this GRA.

Following is a table comparing the change in finance expense in the period of 2024 to 2036 between Appendix 3.4 and MH16 Update with Interim.

Finance Expense Comparison
Period 2024-2036
(in $ millions Canadian Dollars)

	Cumulative Gross Interest	Cumulative PGF
Appendix 3.4	11,617	3,004
Interest Rate for New LTD - 4.10%		
IFF16 Update with Interim	9,931	2,540
Interest Rate for New LTD - 4.45%		
Difference	1,686	464

In the period of 2024 to 2036 there are significant increases in both the cumulative gross interest and PGF amounts in Appendix 3.4 as compared to MH16 Update with Interim. This is due to the fact that in Appendix 3.4, Manitoba Hydro has higher long term debt balances resulting from the need to refinance more long term debt maturities during this period. Less cash is available to for debt retirement in Appendix 3.4 as this scenario has lower rate increases as compared to MH16 Update with Interim. The increase in cumulative gross interest due to lower rate increases is actually higher than shown in the above table as this volume variance is offset by lower forecast interest rates for new long term debt issuance. Appendix 3.4 assumed new Canadian long term debt was issued at 4.10% versus 4.45% in MH16 Update with Interim.

Following is a table comparing the change in finance expense in the period of 2024 to 2036 between Appendix 3.7 scenario 3 and MH16 Update with Interim.

Finance Expense Comparison
Period 2024-2036
(in $ millions Canadian Dollars)

	Cumulative Gross Interest	Cumulative PGF
Appendix 3.7 Scenario 3 Interest Rate for New LTD - 4.45%	11,422	2,859
IFF16 Update with Interim Interest Rate for New LTD - 4.45%	9,931	2,540
Difference	1,491	319

In the period of 2024 to 2036 there are significant increases in both the cumulative gross interest and PGF amounts in Appendix 3.7 scenario 3 as compared to MH16 Update with Interim. This is due to the fact that in Appendix 3.4 Manitoba Hydro has higher long term debt balances resulting from the need to refinance more long term debt maturities during this period. Less cash is available to for debt retirement in Appendix 3.7 scenario 3 as there are lower rate increases as compared to MH16 Update with Interim.

Following are versions of PUB MFR 56 and PUB MFR 55 based on Appendix 3.4 and Appendix 3.7 scenario 3.

Finance Expense - Debt Levels MFR56

MANITOBA HYDRO
Continunity Schedule
Consolidated Short and Long Term Debt

Forecast as per IFF16 with IFF15 Level Rate Increases (Appendix 3.4)
(in $ millions Canadian Dollars)

Long Term Debt	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Forecast 2018	Forecast 2019
Opening Balance	7,268	7,390	7,204	7,169	7,227	7,571	8,187	8,538	8,647	9,382	9,985	10,868	12,680	14,527	16,438	19,539
Long Term Debt Proceeds	1,013	300	180	173	981	423	1,425	915	698	807	1,320	2,210	2,165	2,163	3,500	3,600
Long Term Debt Matured	(473)	(241)	(111)	(80)	(311)	(366)	(452)	(723)	(25)	(242)	(613)	(654)	(362)	(320)	(330)	(1,002)
Carrying Value Adjustments*	(418)	(245)	(104)	(35)	(327)	559	(622)	(83)	62	38	176	256	44	68	(68)	(36)
Closing Balance	**7,390**	**7,204**	**7,169**	**7,227**	**7,571**	**8,187**	**8,538**	**8,647**	**9,382**	**9,985**	**10,868**	**12,680**	**14,527**	**16,438**	**19,539**	**22,101**

* Carrying Value Adjustments include changes in in the value of US dollar denominated debt upon conversion to CAD, as well as changes to the portfolio carrying value for transaction costs, premiums/ discounts, and dual currency bonds.

Short Term Debt	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast 2017	Forecast 2018	Forecast 2019
Opening Balance	128	93	59	-	148	-	100	-	-	-	-	-	-	-	-	-
Increase (Decrease)	(35)	(34)	(59)	148	(148)	100	(100)	-	-	-	-	-	-	-	-	-
Closing Balance	**93**	**59**	**-**	**148**	**-**	**100**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Total Debt	Actual 2004	Actual 2005	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Actual 2010	Actual 2011	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Forecast 2017	Forecast 2018	Forecast 2019
Long Term Debt	7,390	7,204	7,169	7,227	7,571	8,187	8,538	8,647	9,382	9,985	10,868	12,680	14,527	16,438	19,539	22,101
Short Term Debt	93	59		148	-	100	-	-	-	-	-	-	-	-	-	-
Total Debt	**7,483**	**7,263**	**7,169**	**7,375**	**7,571**	**8,287**	**8,538**	**8,647**	**9,382**	**9,985**	**10,868**	**12,680**	**14,527**	**16,438**	**19,539**	**22,101**
Proportion of Short Term Debt to Total Debt	1%	1%	0%	2%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Consolidated Debt Ratio	87%	85%	81%	80%	73%	77%	73%	73%	74%	75%	76%	82%	83%	84%	85%	86%

Finance Expense - Debt Levels MFR56

MANITOBA HYDRO
Continunity Schedule
Consolidated Short and Long Term Debt

Forecast as per IFF16 with IFF15 Level Rate Increases (Appendix 3.4)
(in $ millions Canadian Dollars)

Long Term Debt	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036
Opening Balance	22,101	23,897	24,623	24,766	25,049	24,951	24,941	24,793	24,617	24,669	24,612	23,955	23,362	23,153	22,357	21,991	21,985
Long Term Debt Proceeds	2,200	2,000	1,200	800	200	400	600	1,000	200	-	3,050	3,800	2,000	1,200	800	800	400
Long Term Debt Matured	(356)	(1,278)	(1,020)	(469)	(300)	(412)	(750)	(1,178)	(150)	(60)	(3,710)	(4,396)	(2,212)	(2,000)	(1,169)	(810)	(475)
Carrying Value Adjustments*	(48)	3	(36)	(48)	1	2	2	2	2	3	3	3	3	4	4	4	4
Closing Balance	**23,897**	**24,623**	**24,766**	**25,049**	**24,951**	**24,941**	**24,793**	**24,617**	**24,669**	**24,612**	**23,955**	**23,362**	**23,153**	**22,357**	**21,991**	**21,985**	**21,914**

* Carrying Value Adjustments include changes in in the value of US dollar denominated debt upon conversion to CAD, as well as changes to the portfolio carrying value for transaction costs, premiums/ discounts, and dual currency bonds.

Short Term Debt	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036
Opening Balance	-	-	-	-	-	-	-	58	49	-	-	62	56	13	192	113	-
Increase (Decrease)	-	-	-	-	-	-	58	(9)	(49)	-	62	(7)	(43)	179	(78)	(113)	-
Closing Balance	**-**	**-**	**-**	**-**	**-**	**-**	**58**	**49**	**-**	**-**	**62**	**56**	**13**	**192**	**113**	**-**	**-**

Total Debt	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036
Long Term Debt	23,897	24,623	24,766	25,049	24,951	24,941	24,793	24,617	24,669	24,612	23,955	23,362	23,153	22,357	21,991	21,985	21,914
Short Term Debt	-	-	-	-	-	-	58	49	-	-	62	56	13	192	113	-	-
Total Debt	**23,897**	**24,623**	**24,766**	**25,049**	**24,951**	**24,941**	**24,850**	**24,666**	**24,669**	**24,612**	**24,017**	**23,417**	**23,166**	**22,548**	**22,104**	**21,985**	**21,914**
Proportion of Short Term Debt to Total Debt	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%	0%	0%
Consolidated Debt Ratio	86%	86%	86%	86%	86%	86%	86%	85%	85%	84%	82%	81%	79%	77%	74%	71%	68%

Finance Expense - Debt Levels MFR56

MANITOBA HYDRO
Continunity Schedule
Consolidated Short and Long Term Debt

Forecast as per MH16 Update Scenario 3 (Appendix 3.7)
(in $ millions Canadian Dollars)

Long Term Debt	**Actual 2004**	**Actual 2005**	**Actual 2006**	**Actual 2007**	**Actual 2008**	**Actual 2009**	**Actual 2010**	**Actual 2011**	**Actual 2012**	**Actual 2013**	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Actual 2017**	**Forecast 2018**	**Forecast 2019**
Opening Balance	7,268	7,390	7,204	7,169	7,227	7,571	8,187	8,538	8,647	9,382	9,985	10,868	12,680	14,527	16,438	19,561
Long Term Debt Proceeds	1,013	300	180	173	981	423	1,425	915	698	807	1,320	2,210	2,165	2,163	3,433	3,600
Long Term Debt Matured	(473)	(241)	(111)	(80)	(311)	(366)	(452)	(723)	(25)	(242)	(613)	(654)	(362)	(320)	(330)	(1,002)
Carrying Value Adjustments*	(418)	(245)	(104)	(35)	(327)	559	(622)	(83)	62	38	176	256	44	68	20	(37)
Closing Balance	**7,390**	**7,204**	**7,169**	**7,227**	**7,571**	**8,187**	**8,538**	**8,647**	**9,382**	**9,985**	**10,868**	**12,680**	**14,527**	**16,438**	**19,561**	**22,123**

* Carrying Value Adjustments include changes in in the value of US dollar denominated debt upon conversion to CAD, as well as changes to the portfolio carrying value for transaction costs, premiums/ discounts, and dual currency bonds.

Short Term Debt	**Actual 2004**	**Actual 2005**	**Actual 2006**	**Actual 2007**	**Actual 2008**	**Actual 2009**	**Actual 2010**	**Actual 2011**	**Actual 2012**	**Actual 2013**	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Forecast 2017**	**Forecast 2018**	**Forecast 2019**
Opening Balance	128	93	59	-	148	-	100	-	-	-	-	-	-	-	-	-
Increase (Decrease)	(35)	(34)	(59)	148	(148)	100	(100)	-	-	-	-	-	-	-	-	-
Closing Balance	**93**	**59**	**-**	**148**	**-**	**100**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Total Debt	**Actual 2004**	**Actual 2005**	**Actual 2006**	**Actual 2007**	**Actual 2008**	**Actual 2009**	**Actual 2010**	**Actual 2011**	**Actual 2012**	**Actual 2013**	**Actual 2014**	**Actual 2015**	**Actual 2016**	**Forecast 2017**	**Forecast 2018**	**Forecast 2019**
Long Term Debt	7,390	7,204	7,169	7,227	7,571	8,187	8,538	8,647	9,382	9,985	10,868	12,680	14,527	16,438	19,561	22,123
Short Term Debt	93	59		148	-	100	-	-	-	-	-	-	-	-	-	-
Total Debt	**7,483**	**7,263**	**7,169**	**7,375**	**7,571**	**8,287**	**8,538**	**8,647**	**9,382**	**9,985**	**10,868**	**12,680**	**14,527**	**16,438**	**19,561**	**22,123**
Proportion of Short Term Debt to Total Debt	1%	1%	0%	2%	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Consolidated Debt Ratio	87%	85%	81%	80%	73%	77%	73%	73%	74%	75%	76%	82%	83%	84%	85%	85%

Finance Expense - Debt Levels MFR56

MANITOBA HYDRO
Continunity Schedule
Consolidated Short and Long Term Debt

Forecast as per MH16 Update Scenario 3 (Appendix 3.7)
(in $ millions Canadian Dollars)

Long Term Debt	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036
Opening Balance	22,123	23,920	24,808	24,428	24,628	24,248	23,838	23,690	23,514	23,567	23,509	22,852	22,059	21,850	21,029	21,097	20,537
Long Term Debt Proceeds	2,200	2,200	1,000	1,400	-	-	600	1,000	200	-	1,850	3,600	2,000	1,400	1,000	800	200
Long Term Debt Matured	(369)	(1,293)	(1,366)	(1,161)	(300)	(412)	(750)	(1,178)	(150)	(60)	(2,510)	(4,396)	(2,213)	(2,225)	(936)	(1,364)	(275)
Carrying Value Adjustments*	(34)	(19)	(15)	(38)	(80)	2	2	2	2	3	3	3	3	4	4	4	4
Closing Balance	**23,920**	**24,808**	**24,428**	**24,628**	**24,248**	**23,838**	**23,690**	**23,514**	**23,567**	**23,509**	**22,852**	**22,059**	**21,850**	**21,029**	**21,097**	**20,537**	**20,466**

* Carrying Value Adjustments include changes in in the value of US dollar denominated debt upon conversion to CAD, as well as changes to the portfolio carrying value for transaction costs, premiums/ discounts, and dual currency bonds.

Short Term Debt	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036
Opening Balance	-	-	-	-	-	12	42	-	-	-	-	-	27	-	105	-	-
Increase (Decrease)	-	-	-	-	12	30	(42)	-	-	-	-	27	(27)	105	(105)	-	-
Closing Balance	**-**	**-**	**-**	**-**	**12**	**42**	**-**	**-**	**-**	**-**	**-**	**27**	**-**	**105**	**-**	**-**	**-**

Total Debt	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036
Long Term Debt	23,920	24,808	24,428	24,628	24,248	23,838	23,690	23,514	23,567	23,509	22,852	22,059	21,850	21,029	21,097	20,537	20,466
Short Term Debt	-	-	-	-	12	42	-	-	-	-	-	27	-	105	-	-	-
Total Debt	**23,920**	**24,808**	**24,428**	**24,628**	**24,260**	**23,880**	**23,690**	**23,514**	**23,567**	**23,509**	**22,852**	**22,087**	**21,850**	**21,134**	**21,097**	**20,537**	**20,466**
Proportion of Short Term Debt to Total Debt	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Consolidated Debt Ratio	85%	84%	83%	83%	82%	81%	81%	80%	79%	78%	77%	75%	73%	71%	68%	65%	62%

Finance Expense - MFR55

MANITOBA HYDRO
Summary of Total Finance Expense

Forecast as per IFF16 with IFF15 Level Rate Increases (Appendix 3.4)
(in $ millions Canadian Dollars)

	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024
Interest on Short & Long Term Debt													
Gross Interest	490	515	528	569	645	707	758	782	835	872	900	905	908
Provincial Guarantee Fee	82	90	96	105	118	132	153	185	212	230	241	242	246
Amortization of (Premiums), Discounts, and Transaction Costs	0	0	2	2	2	2	1	1	1	3	3	2	(0)
Intercompany Interest Receivable	(17)	(19)	(19)	(14)	(14)	(14)	(15)	(16)	(16)	(17)	(18)	(18)	(19)
Total Interest on Short & Long Term Debt	**555**	**587**	**608**	**663**	**751**	**827**	**898**	**953**	**1,032**	**1,088**	**1,126**	**1,131**	**1,135**
Interest Allocated to Construction	**(167)**	**(138)**	**(140)**	**(145)**	**(176)**	**(247)**	**(353)**	**(313)**	**(315)**	**(329)**	**(289)**	**(55)**	**(19)**
Interest Earned on Sinking Fund	(10)	(10)	(24)	0	(0)	(0)	(1)	(7)	(13)	(13)	(12)	(2)	(2)
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	(0)	2	(19)	(6)	(6)	15	18	16	13	15	10	0	-
Revaluation of Dual Currency Bonds	3	3	2	1	1	1	1	1	1	1	2	2	2
Corporate Allocation	(19)	(19)	(19)	(19)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)
Other Amortization	24	27	28	20	31	30	30	31	31	50	46	48	47
Total Finance Expense	**385**	**452**	**435**	**515**	**582**	**608**	**574**	**664**	**731**	**794**	**864**	**1,105**	**1,144**

	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036
Interest on Short & Long Term Debt												
Gross Interest	915	904	908	918	918	895	918	890	887	872	854	829
Provincial Guarantee Fee	246	244	243	239	238	235	229	226	222	217	211	208
Amortization of (Premiums), Discounts, and Transaction Costs	1	1	2	2	2	3	3	3	4	4	4	4
Intercompany Interest Receivable	(20)	(20)	(21)	(21)	(22)	(22)	(23)	(23)	(24)	(24)	(25)	(26)
Total Interest on Short & Long Term Debt	**1,142**	**1,129**	**1,132**	**1,138**	**1,136**	**1,111**	**1,127**	**1,097**	**1,089**	**1,069**	**1,044**	**1,016**
Interest Allocated to Construction	**(19)**	**(18)**	**(20)**	**(20)**	**(24)**	**(22)**	**(23)**	**(19)**	**(18)**	**(19)**	**(21)**	**(24)**
Interest Earned on Sinking Fund	(3)	(3)	(4)	(9)	(18)	(10)	(10)	(9)	(13)	(16)	(26)	(28)
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	-	-	-	-	-	-	-	-	-	-	-	-
Revaluation of Dual Currency Bonds	2	1	-	-	-	-	-	-	-	-	-	-
Corporate Allocation	(18)	(18)	(18)	(18)	(18)	(15)	(13)	(13)	(13)	(13)	(13)	(13)
Other Amortization	45	44	43	41	40	39	38	37	35	34	33	32
Total Finance Expense	**1,149**	**1,135**	**1,133**	**1,131**	**1,116**	**1,103**	**1,120**	**1,093**	**1,080**	**1,055**	**1,017**	**983**

Finance Expense - MFR55

MANITOBA HYDRO
Summary of Total Finance Expense

Forecast as per MH16 Update Scenario 3 (Appendix 3.7)
(in $ millions Canadian Dollars)

	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Actual 2016	Actual 2017	Forecast 2018	Forecast 2019	Forecast 2020	Forecast 2021	Forecast 2022	Forecast 2023	Forecast 2024
Interest on Short & Long Term Debt													
Gross Interest	490	515	528	569	645	707	765	787	838	888	903	913	918
Provincial Guarantee Fee	82	90	96	105	118	132	154	186	212	230	239	238	241
Amortization of (Premiums), Discounts, and Transaction Costs	0	0	2	2	2	2	1	1	1	3	3	2	(0)
Intercompany Interest Receivable	(17)	(19)	(19)	(14)	(14)	(14)	(15)	(15)	(16)	(17)	(18)	(19)	(19)
Total Interest on Short & Long Term Debt	**555**	**587**	**608**	**663**	**751**	**827**	**906**	**960**	**1,035**	**1,104**	**1,127**	**1,134**	**1,140**
Interest Allocated to Construction	**(167)**	**(138)**	**(140)**	**(145)**	**(176)**	**(247)**	**(360)**	**(320)**	**(319)**	**(333)**	**(290)**	**(55)**	**(19)**
Interest Earned on Sinking Fund	(10)	(10)	(24)	0	(0)	(0)	(1)	(6)	(14)	(15)	(14)	(2)	(2)
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	(0)	2	(19)	(6)	(6)	15	27	28	28	29	29	9	-
Revaluation of Dual Currency Bonds	3	3	2	1	1	1	1	1	1	1	2	2	2
Corporate Allocation	(19)	(19)	(19)	(19)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)	(18)
Other Amortization	24	27	28	20	31	30	32	32	31	50	48	50	48
Total Finance Expense	**385**	**452**	**435**	**515**	**582**	**608**	**587**	**676**	**744**	**817**	**882**	**1,119**	**1,150**

	Forecast 2025	Forecast 2026	Forecast 2027	Forecast 2028	Forecast 2029	Forecast 2030	Forecast 2031	Forecast 2032	Forecast 2033	Forecast 2034	Forecast 2035	Forecast 2036
Interest on Short & Long Term Debt												
Gross Interest	909	893	900	907	906	888	899	862	863	849	827	801
Provincial Guarantee Fee	238	234	232	228	227	225	217	213	209	202	200	193
Amortization of (Premiums), Discounts, and Transaction Costs	1	1	2	2	2	3	3	3	4	4	4	4
Intercompany Interest Receivable	(20)	(21)	(22)	(22)	(23)	(23)	(24)	(24)	(25)	(25)	(26)	(27)
Total Interest on Short & Long Term Debt	**1,128**	**1,107**	**1,112**	**1,115**	**1,113**	**1,093**	**1,095**	**1,054**	**1,050**	**1,030**	**1,005**	**971**
Interest Allocated to Construction	**(19)**	**(18)**	**(20)**	**(20)**	**(24)**	**(22)**	**(23)**	**(19)**	**(18)**	**(19)**	**(21)**	**(24)**
Interest Earned on Sinking Fund	(4)	(3)	(5)	(9)	(18)	(21)	(20)	(10)	(19)	(20)	(30)	(32)
Realized Foreign Exchange (Gains) or Losses on Debt in Cash Flow Hedges	-	-	-	-	-	-	-	-	-	-	-	-
Revaluation of Dual Currency Bonds	2	1	-	-	-	-	-	-	-	-	-	-
Corporate Allocation	(18)	(18)	(18)	(18)	(18)	(16)	(14)	(14)	(14)	(14)	(14)	(14)
Other Amortization	46	44	43	42	40	39	38	37	35	34	33	32
Total Finance Expense	**1,135**	**1,113**	**1,112**	**1,108**	**1,093**	**1,073**	**1,077**	**1,049**	**1,035**	**1,012**	**973**	**934**