The Acquisition of Ancillary Services in 2001 and Beyond

ESBI ALBERTA LTD.

TRANSMISSION ADMINISTRATOR

Discussion Paper
FINAL
2000 July 26

Document Revision History

Draft #5 (Final): 2000 July 26

- Adjustments have been made to the document in light of the Alberta Energy and Utilities Board's recent decision[1] on Appendix E to the 2001 transmission tariff application.
- Editorial changes have been made to Section 7 to improve its clarity.
- An "operations walkthrough" has been added to Section 7 to show how market-procured ancillary services will be used in the operation of the Alberta Interconnected Electric System.
- Appendix D has been added to address stakeholder comments made at the 2000 May 31 Ancillary Services Group meeting and the 2000 June 22 consultation session.
- The Transmission Administrator's response to some questions on market design raised by the Power Pool of Alberta has been added as Appendix E.

Draft #4: 2000 May 18

- The brief overview of ancillary services contained in Section 6 has been moved to Section 1.
- Sections 3, 4, and 5 have been updated to include questions that arose during meetings of the Ancillary Services Group during February and March.
- Section 6 has been modified to include only the ancillary service procurement principles.
- A new Section 7, which contains the recommended market design, has been written.
- A new Section 8 has been added to illustrate, by answering the questions raised in Sections 3, 4, and 5, how the recommended market design satisfies the success criteria and addresses the issues raised by stakeholders.

Draft #3: 2000 February 22

- The term *ancillary services* has been substituted for *system support services.* The former term is more familiar to potential PPA bidders from outside Alberta.
- Sections 3.1 and 3.2 have been combined, and subsequent parts of Section 3 have been renumbered accordingly.
- Section 6 has been changed to contain a statement of principles and a *conceptual* overview of how contestable ancillary services might be procured in the future.
- Feedback received from stakeholders at the consultation session held on 2000 January 20 has been summarized in Appendix B.

Draft #2: 2000 January 14

- Feedback received from stakeholders at consultation sessions held on 1999 December 13 and 14 has been summarized in Appendix A.
- Section 6 on preliminary procurement concepts has been added. (Concluding Remarks have been moved to the new Section 7.)
- The discussion of the hydro PPAs in Section 2.8 has been amended to clarify the form of the payments to be made by the Owner to the balancing pool.
- The brief discussion of incentive regulation with respect to ancillary services in Section 3.3 has been removed. A new document specifically focussed thereon will be created.
- A few minor editorial changes have been made.

Draft #1: 1999 December 6

- Initial draft.

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[1] Decision 2000-46, *ESBI Alberta Ltd., 2001 General Tariff Application, Phase I & II, Part A: System Support Services - Thermal Power Purchase Arrangements (Appendix E).*

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1 INTRODUCTION

1.1 Background

ESBI Alberta Ltd. first presented its views on the competitive procurement of ancillary (system support) services in a December 1998 document entitled *System Support Services in the Restructured Alberta Electricity Industry*. Competitive procurement concepts were subsequently outlined in the Transmission Administrator's response to AEUB directives[2] in EAL's 1999/2000 tariff application. Since that time, EAL has continued to refine its ancillary service acquisition proposals. In December 1999, the first draft of the present document was published as a focal point for discussions between the Transmission Administrator and its stakeholders. It was suggested at that time that an appropriate mechanism for acquiring certain ancillary services would be a competitive market. The AEUB provided some support for the market concept in Decision U99099,[3] in which it wrote that it "...expects that the Transmission Administrator would develop a market for system support services…"

EAL continued its market development efforts with stakeholder consultations in Edmonton and Calgary in December 1999. Based on its own views and feedback from session participants, EAL developed general procurement principles and an initial market proposal. Following publication of Draft 2 of this document another consultation session was held, during which there was broad agreement that the general procurement principles were appropriate. At that consultation session it was agreed that a group should be formed to work out market design details and bring recommendations back to the larger stakeholder group for review.

Shortly after the publication of Draft 3 of this paper, the first meeting of the Ancillary Services Group[4] (ASG) was held. Based in part on discussions held in that forum, a small team of EAL staff and consultants met to develop a design for an ancillary services market. In the Transmission Administrator's view the design, which was first set out in Draft 4, meets the criteria for a successful market described in this document.

This fifth draft provides additional details about the market design, particularly with respect to how the ancillary services procured in the market will be employed by the Transmission Administrator and the System Controller in Alberta Interconnected Electric System operations. It also addresses points raised by stakeholders following the publication of Draft 4.

The Transmission Administrator considers this to be the final version of this document and intends to proceed with detailed market design and development—in conjunction with one or more private market operators—based on the design concepts presented. Other documents, including technical and commercial specifications for each ancillary service, supplier qualification criteria and procedures, market rules, and market participation agreements will now become the focus of work.

ESBI Alberta Ltd. would like to express its sincere thanks to stakeholders, and in particular the members of the Ancillary Services Group, for their contributions to date, and looks forward to their continuing contributions toward the successful development and implementation of an ancillary services market for Alberta.

1.2 Document Outline

Following a brief description of the ancillary services to be procured by the Transmission Administrator in 2001 and beyond (Section 1.3), this paper provides, in Section 2, a "success map" for ancillary services procurement. Section 3 discusses the role of the Transmission Administrator, while Section 4 deals with three broad classes of ancillary service procurement options. Section 5 discusses market design and operations issues, including interaction with the energy market, pricing, and participant obligations. Section 6 presents some ancillary service acquisition principles.

Section 7, which presents the recommended design for an Alberta ancillary service market, is the central feature of this paper. Following an overview of the market, there are discussions of the proposed market structure, the products to be traded, and the mechanics of trading. Market and operational walkthroughs are provided to further clarify the operation of the proposed market.

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[2] *ESBI Alberta Ltd. (EAL) 99/00 Tariff – Phase II*, Tab 3, Appendix A.

[3] *1999/2000 Electric Tariff Application, ATCO Electric Ltd., EPCOR Generation Inc., EPCOR Transmission Inc., TransAlta Utilities Corporation*, Part 1, Section 3(a)(1)(D)(ii).

[4] A Terms of Reference for this group can be found in Appendix C.

Sections 3, 4, and 5 were included in early drafts of this document to stimulate discussion on ancillary service procurement issues and options. To a large extent the issues have been addressed and procurement options have been selected. Further, some of the concepts described in those sections have evolved. Thus, Sections 3 through 5 could be considered obsolete. However, to preserve continuity, to ensure that stakeholder concerns have been addressed, and to make stakeholders aware of the rationale for the choices that were made, Section 8 provides responses to the questions raised in those three sections. The answers are, of course, based on the procurement principles and market design presented in Sections 6 and 7.

Appendices A through E provide a record of stakeholder consultation and feedback, and also serve a purpose similar to that of Section 8.

1.3 Ancillary Services Overview

The following is a short description of each of the ancillary services procured by the Transmission Administrator.

- *Power System Restoration (Black Start)* is a service provided by generation units that can go from a shutdown condition to an operating condition without assistance from the electric system and deliver their energy output to the transmission system. It is a rarely used but critical service that involves not only the provision of equipment, but also the development of emergency procedures and the periodic testing thereof.

- *Reactive Power and Voltage Control* is used to maintain transmission voltages and energy transfer capability through changes in reactive power injections or withdrawals.

- *Regulating Reserve*, also called regulation, is that service whose objective is to follow the moment-to-moment variations in supply and demand in a control area and to maintain the scheduled interconnection frequency. Regulating reserve levels must be maintained even if non-recallable (firm) load must be curtailed. Generators providing regulating reserve must respond to automatic generation control (AGC) signals on a moment-to-moment basis.

- *Load Following* is that service whose objective is to follow the supply/demand imbalances that occur within a scheduling period (currently one hour). The requirements are similar, but not identical, to those for regulating reserve. The primary difference between the two is the time period over which the load variations occur, with load following providers being required to respond to dispatches from the System Controller at intervals of (roughly) ten minutes or longer.

- *Spinning Reserves* consist of additional capacity from generators that are on-line, loaded to less than their maximum output, and available to serve customer demand immediately should a contingency occur.

- *Supplemental (Non-spinning) Reserves* may take the form of off-line (unsynchronized) generators that can produce output, or on-line loads that can be curtailed, within 7 minutes of an instruction from the System Controller.

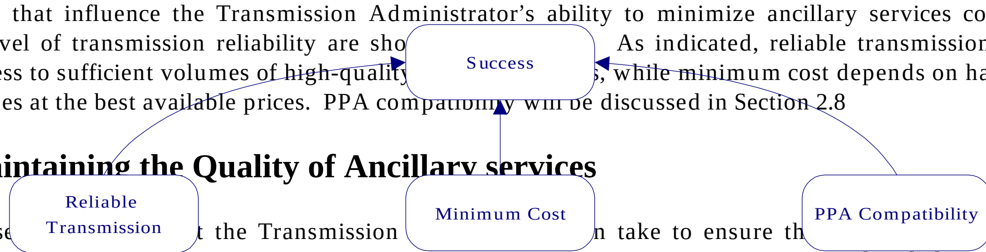
2 THE ANCILLARY SERVICES "SUCCESS MAP"

In this section we develop, piece by piece, a "success map" for ancillary services procurement. There are several reasons for doing so. First, the map will make explicit, for stakeholder review and comment, certain assumptions about what constitutes success in the procurement of ancillary services by the Transmission Administrator. Second, the map helps to illustrate the interactions among the many issues that must be addressed.[5] Finally, the map highlights a number of criteria against which ancillary service procurement options can be evaluated.

2.1 System Reliability at Minimum Cost

The first piece of the map is shown in Figure 2.1, where success is represented as the provision of *reliable transmission* at *minimum cost*.[6] A secondary objective, but nevertheless an important one, is *PPA compatibility;* that is, the selected ancillary services procurement methods must be compatible with the thermal and hydro PPAs.

The factors that influence the Transmission Administrator's ability to minimize ancillary services costs given the required level of transmission reliability are sho[illegible] As indicated, reliable transmission depends on having access to sufficient volumes of high-quality [illegible], while minimum cost depends on having not-too-high volumes at the best available prices. PPA compatibility will be discussed in Section 2.8

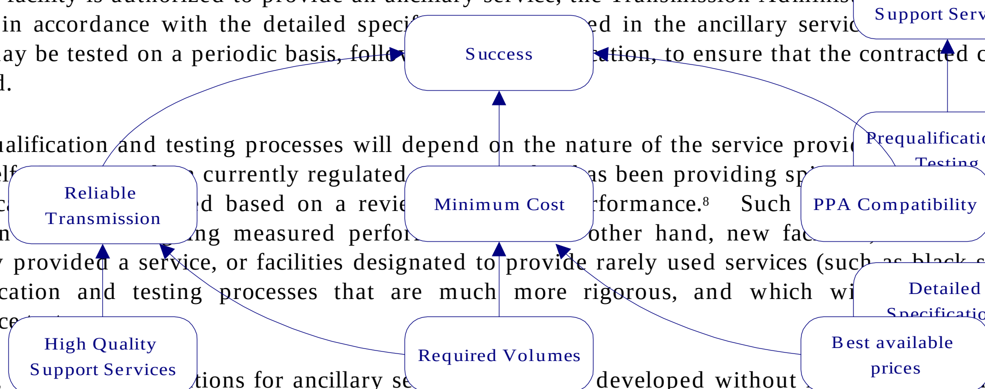


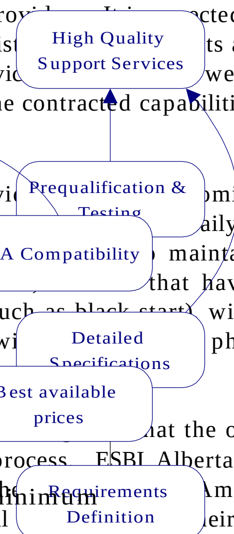
2.2 Maintaining the Quality of Ancillary services

There are se[illegible]t the Transmission [illegible]n take to ensure th[illegible]llary services delivered to the interconnected electric system, as shown in Figure 2.3. The first is to create *detailed specifications* for each of the services. ESBI Alberta Ltd. will develop, in consultation with industry stakeholders, contracts that will allow it to maintain the reliability of the transmission system while simultaneously addressing the legitimate commercial concerns of both buyers and sellers.[7]

Figure 2.1: The three fundamental objectives of the system support services procurement process.

A second component of quality assurance is the *pre-qualification and testing* of service prov[illegible]cted that, before any facility is authorized to provide an ancillary service, the Transmission Adminis[illegible]ts ability to deliver in accordance with the detailed speci[illegible]ed in the ancillary servic[illegible] well, the facilities may be tested on a periodic basis, follo[illegible]ation, to ensure that the contracted capabilities are maintained.





The pre-qualification and testing processes will depend on the nature of the service provi[illegible]ominated facility itself[illegible] currently regulated [illegible]as been providing sp[illegible]aily basis for years c[illegible]d based on a revie[illegible]rformance.[8] Such [illegible] maintain its certification [illegible]ng measured perfor[illegible] other hand, new fac[illegible] that have not historically provided a service, or facilities designated to provide rarely used services (such as black start) will face pre-qualification and testing processes that are much more rigorous, and which wi[illegible] physical performance [illegible]

Obviously, [illegible]tions for ancillary se[illegible] developed without [illegible]at the overall requirements are. These are established through an ongoing *requirements definition* process. ESBI Alberta Ltd's engineering staff make use of planning and technical studies, recommendations establishe[illegible] American Electric Reliability Council (NERC) and the Western Systems Coordinating Council [illegible]eir own professional judgement in establishing these requirements. As the Alberta interconnected electric system evolves, so will its ancillary services requirements.

Figure 2.2: The factors involved in ensuring reliable transmission at minimum cost.

Figure 2.3: Ensuring the quality of support services.

2.3 Obtaining the Required Volumes

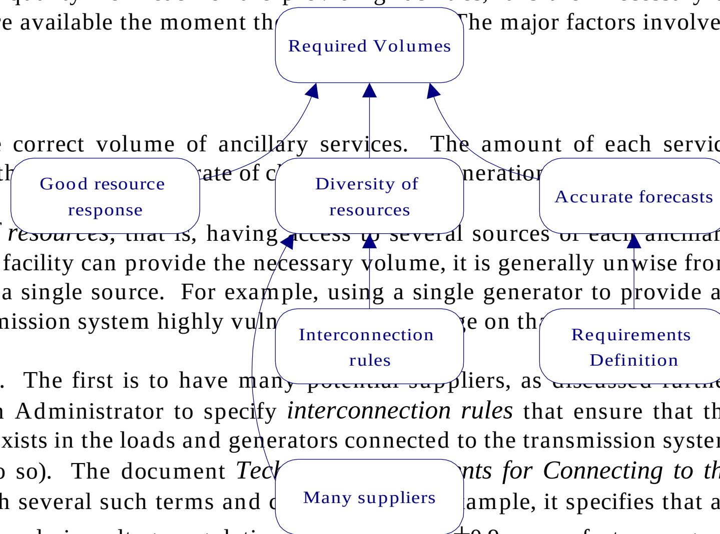
[5] Note that it is neither intended nor possible to show every conceivable interaction between the many components of the map; hopefully the main ones have been captured.

[6] It would not be in consumers' interests generally for the Transmission Administrator to minimize the cost of transmission by causing a more-than-offsetting rise in the cost of energy. However, the focus here is on those costs that are, at least to a reasonable degree, within the control of the Transmission Administrator.

[7] The plural form of *buyer* is used because, depending on the ancillary services procurement processes ultimately selected, and the design of any related market structures, the Transmission Administrator may not be the only buyer. This is discussed in more detail later.

[8] This statement should not be taken to imply that any of the currently regulated facilities have failed in their obligations to deliver ancillary services when required to do so.

Given the delivery of ancillary services of high quality from each of the providing facilities, it is then necessary to ensure that adequate volumes of such services are available the moment th[illegible]he major factors involved are shown in Figure 2.4.



Accurate forecasts are helpful in acquiring the correct volume of ancillary services. The amount of each service needed depends on real-time conditions such as th[illegible]ate of c[illegible]neration[illegible]

The second requirement is having a *diversity of re*[illegible], having [illegible] several sources [illegible] service. Even if a single, economically attractive facility can provide the necessary volume, it is generally unwise from a reliability perspective to limit procurement to a single source. For example, using a single generator to provide all required spinning reserve would leave the transmission system highly vuln[illegible]e on th[illegible]

Resource diversity can be fostered in two ways. The first is to have man[illegible]pliers, as [illegible]er Section 2.5. The second is for the Transmission Administrator to specify *interconnection rules* that ensure that the physical capability to provide ancillary services exists in the loads and generators connected to the transmission system (when, of course, it is fair and reasonable to do so). The document *Tec*[illegible]*nts for Connecting to the Alberta Interconnected Electric System*[9] sets forth several such terms and c[illegible]ample, it specifies that all generators must be capable of operating continuously in voltage regulation mode within a ±0.9 power factor range at nominal power output.

Figure 2.4: Ensuring that the required volume of system support services is available.

The final requirement for ensuring that sufficient ancillary services volumes are available is a *good resource response* to directives from the System Controller. That is, suppliers must deliver the service within a contractually specified period; otherwise, the transmission system could be put at risk. Figure 2.5 shows the factors that can influence supplier response. One of these is having an *efficient, effective dispatch,* which will be discussed in more detail in Section 2.7. The other factors, which are closely related to each other, are *compliance monitoring* and *consequences for non-compliance.* A compliance monitoring process will be established to continually review the response of ancillary service providers to dispatch directives. If any response is found to be outside the bounds established in the specifications, there will likely be financial and/or other consequences for the supplier. The most obvious consequence is that a party who fails to deli[illegible]tions should be required to pay any additional costs incurred by the Transmission Administrator [illegible] the shortfall. Other consequences could include an assessment of penalties[10] and, ultimately, remov[illegible] of approved ancillary service suppliers.

2.4 Accessing the Best Available Prices

The ability of the Transmission Administrator to access t[illegible] prices c[illegible] of many suppliers, a lack of market power, and an efficient procurement process, as shown in Figure 2.6. The first factor will be discussed in the next section. The second, namely market power, will depend to a large extent on the outcome of the PPA auction, and is therefore beyond the scope of this discussion. However, market power [illegible]nced by market rules. For example, the New York Mercantile Exc[illegible] imposes spot-m[illegible]nd any-one-month limits on the gross number of contracts held by [illegible]quate considerati[illegible] to such rules in any proposal for ancillary service procurement.

The third prerequisite for accessing the best available prices is an efficient procurement process. This in turn means having a [illegible]s, that [illegible]t does [illegible]osts on [illegible]mission Adminis[illegible]s. Thu[illegible] extre[illegible]ve to a[illegible] impose substantial business costs on potential suppliers, will result in cumbersome and inefficient ancillary services procurement.

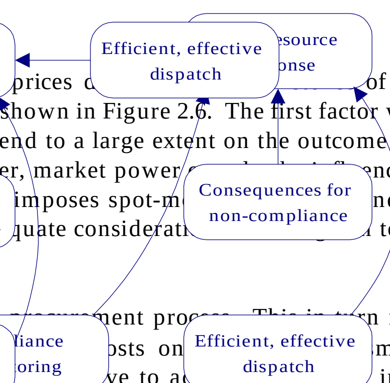


Figure 2.5: Managing the response of support services resources.

In addition to a low-cost process, successful acquisition [illegible] *efficient, effective dispatch* process that delivers the most economic set of the available resources [illegible] also requires an *efficient energy market interaction,* since the resources that provide ancillary services will generally also have opportunities or obligations in the energy market. These topics are discussed in Sections 2.7 and 5.2, respectively.

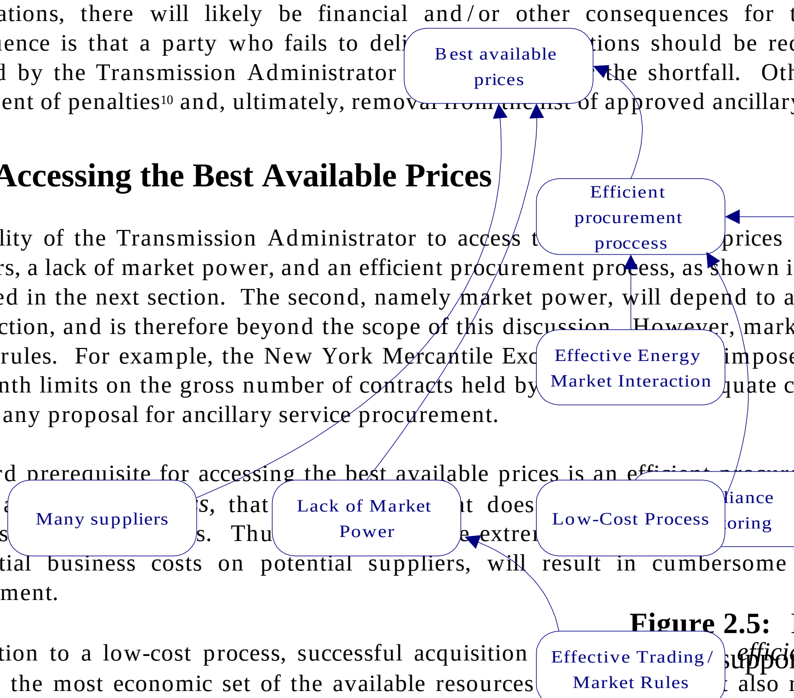


Figure 2.6: Accessing the best available prices for system support services.

[9] See the Technical Documents section at http://www.eal.ab.ca.

[10] The WSCC levies fines on control areas that violate certain criteria laid out in interconnection agreements.

2.5 Ensuring a Sufficient Number of Potential Suppliers

The number of potential suppliers of ancillary services heavily influences both the diversity of resources available to the Transmission Administrator and the cost of those resources. Clearly, in both cases, the larger the number of potential suppliers the better. Four of the influencing factors are shown in Figure 2.7.

Among other things, the ancillary services procurement mechanisms chosen must present *low entry barriers*. That is, the rules of the game must be such that they encourage, rather than discourage, participation. One way of doing this is for the Transmission Administrator to focus on results rather than methods. For example, if interruptible load can provide the same end result (e.g., area control error returned to zero) as generation, it would be inadvisable to define the service such that only generators can provide it. Other examples of minimizing entry barriers include: setting market rules that require lower, rather than higher, levels of creditworthiness; rules that encourage the participation of parties from outside Alberta; and transmission rates (both in Alberta and other control areas) that allow service provision without leading to unnecessarily higher access charges.

Another method of increasing the number of suppliers is to increase the available *market opportunities*. As Figure 2.7 shows, one way of doing this is to have *short procurement intervals*. For example, an annual request for proposals for spinning reserve, which results in unsuccessful bidders waiting a year before another opportunity arises, is unlikely to encourage them to invest the funds necessary to maintain their ancillary services capabilities. Note, however, that procurement complexity is likely to rise as acquisition periods get shorter. An appropriate balance must be struck.

Reliable market prices are also a prerequisite to adequate participation. Suppliers' interest is likely to be limited if the prices they receive for their services do not reflect costs, current conditions in related markets (the prime example being the energy market), and conditions on the physical transmission system. Market pricing options are discussed in more detail in Section 5.3.

The fourth and final factor shown in Figure 2.7 is *risk mitigation opport*[illegible]er entering a contract to provide ancillary services faces a risk that the facility designated to provid[illegible] be out of service. If, as was suggested above, the supplier then faces replacement cost risk and possibly penalty risk, then the absence of mitigation possibilities will result in either limited participation or the addition of higher risk premiums to offered prices. Note that risk levels are affected by the procurement period; longer-term commitments are associated with higher physical risks (e.g., unexpected outages) and greater deviations betw[illegible]actuals.

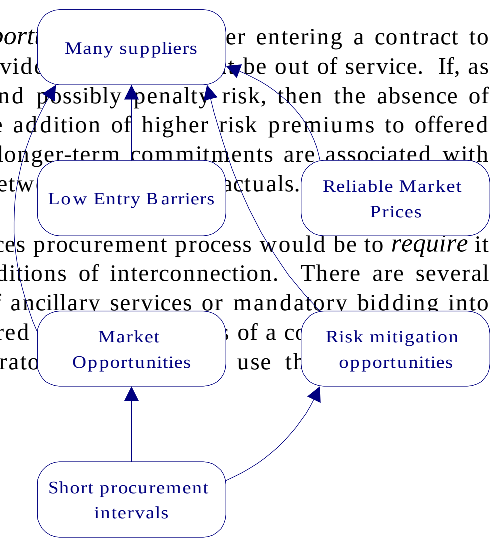


Figure 2.7: Increasing the number of potential suppliers.

Another tactic for ensuring adequate participation in any ancillary services procurement process would be to *require* it through the transmission access tariff or through the terms and conditions of interconnection. There are several possible mechanisms, including mandatory provision of one's share of ancillary services or mandatory bidding into some kind of ancillary services market. While such rules may be required [illegible] of a c[illegible] to ensure its orderly development, it is the Transmission Administrato[illegible] use th[illegible] discussed to encourage participation.

2.6 Managing Risk

Figure 2.8 shows some of the possibilities for risk mitigation, both for suppliers and for the Transmission Administrator. The positive influence of short procurement intervals on risk has already been noted. Another factor is *real-time trading*, which can help both the Transmission Administrator and suppliers to manage their risks. For the former, real-time (or close to it) trading can provide the adjustments needed to account for deviations between forecast and actual requirements. For both the Transmission Administrator and suppliers, real-time trading can facilitate the acquisition of replacement facilities in the event of an unexpected outage.

The two other factors shown in Figure 2.8 are *forward contracts* and *option contracts*. Forward contracts can help manage risk for both buyers and sellers by fixing a price over some future time, thereby limiting the volatility in prices and cash flows for both parties. Option contracts can provide "just in cas[illegible] buyer[illegible] buyer's obligations can be met in the event of an unexpected outage. A b[illegible]xercise[illegible] because it is cheaper to obtain the ancillary services from the seller than to provide them itself. It should be noted that real-time trading, forward contracts, and option contracts may involve a level of market sophistication beyond that necessary or advisable in Alberta. A great deal of discussion is still required in this area.

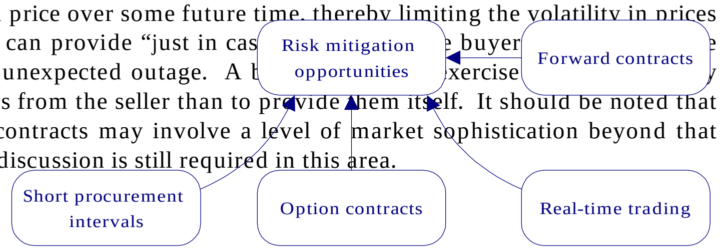


Figure 2.8: Possibilities for risk mitigation.

2.7 Ancillary Services Dispatch Processes

As noted above, the processes used to dispatch ancillary services affect both the response of the resources—and therefore the reliability of the transmission system—and the cost of those services. There are several factors that must be considered in developing the dispatch process, as shown in Figure 2.9.

The first of these is *real-time control and feedback*. Resources cannot be dispatched effectively if the System Controller does not have knowledge and visibility of their availability. Immediate feedback on compliance with dispatch instructions is also critical [illegible] requirement is a *dynamic ancillary services merit order*, that is, an up-to-date view of what resour[illegible] what prices. The more dynamic this list, the higher the likelihood that the most economically efficient dispatch will be executed. The quality of the ancillary services merit order, and therefore the economic efficiency of the dispatch, may be enhanced if option contracts and real-time trading are available.

I[illegible] dispatch [illegible] ardless of the procurement model(s) ultimately chosen, the Transmission A[illegible] establis[illegible] *gations* on transmission customers. These obligations will ensure that the System Controller can continue to operate the transmission system under emergency conditions, or procure ancillary services if the procurement process fails to make adequate resources available. The final form of these obligations is given in Appendix E of EAL's 2001 Phase II Tariff (TA01). The basic principles embodied therein are that the d[illegible] ystem C[illegible] compl[illegible] party should suffer financially as a result of that c[illegible]

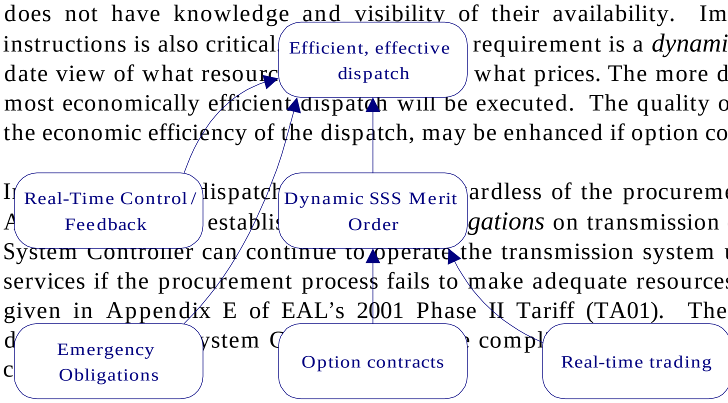


Figure 2.9: Creating an efficient and effective system support services dispatch process.

2.8 PPA Compatibility

The PPAs for the thermal units give the right to offer ancillary services to the PPA buyers. Assuming there is nothing in the ancillary services procurement methods that would discriminate against PPA buyers there ought to be no difficulty maintaining compatibility between future procurement and the thermal PPAs. The hydro PPAs, however, establish fixed-for-floating swaps between the Balancing Pool and TransAlta Utilities, the owner of the hydro units.[11] Under the terms of the swap, the Balancing Pool will make a monthly fixed payment[12] to TransAlta, and TransAlta will make monthly variable payments—related in part to ancillary services—to the Balancing Pool.

Variable payments for regulating reserve, spinning reserve, and non-spinning reserve are each calculated as the product of a PPA-specified reserve quantity and a "market clearing price set for [that] particular class or type of Reserve as determined in accordance with a market for Reserve set up and operated by the Transmission Administrator."[13] Such market clearing prices are to be established for each *settlement period*, with each such period currently defined as one hour. Thus, the variable payments established in the hydro PPAs are based on the existence of hourly market clearing prices for each of the different types of reserves available from the hydro units.[14] Clearly the *reliable market prices* discussed in Section 2.5 will be necessary for PPA compatibility. Possible price-setting mechanisms will be discussed in Section 5.3.

A summary of the success factors discussed in this section is provided in Figure 2.10 on the next page.

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[11] *Power Purchase Arrangement, Hydro Plants, Under Section 45.95(1) of the Electric Utilities Act,* Independent Assessment Team Report to the Alberta Energy and Utilities Board, 1999 August 27.

[12] Ibid., Schedule B.

[13] Ibid., Definition of Reserve Price on page 6.

[14] Nothing precludes the derivation of hourly market clearing prices from prices that apply over other time intervals. It is conceivable, for example, that three daily prices (off-peak, on-peak, and super-peak) could be established for one or more ancillary services. Each hourly price would simply be the price established for the corresponding interval.

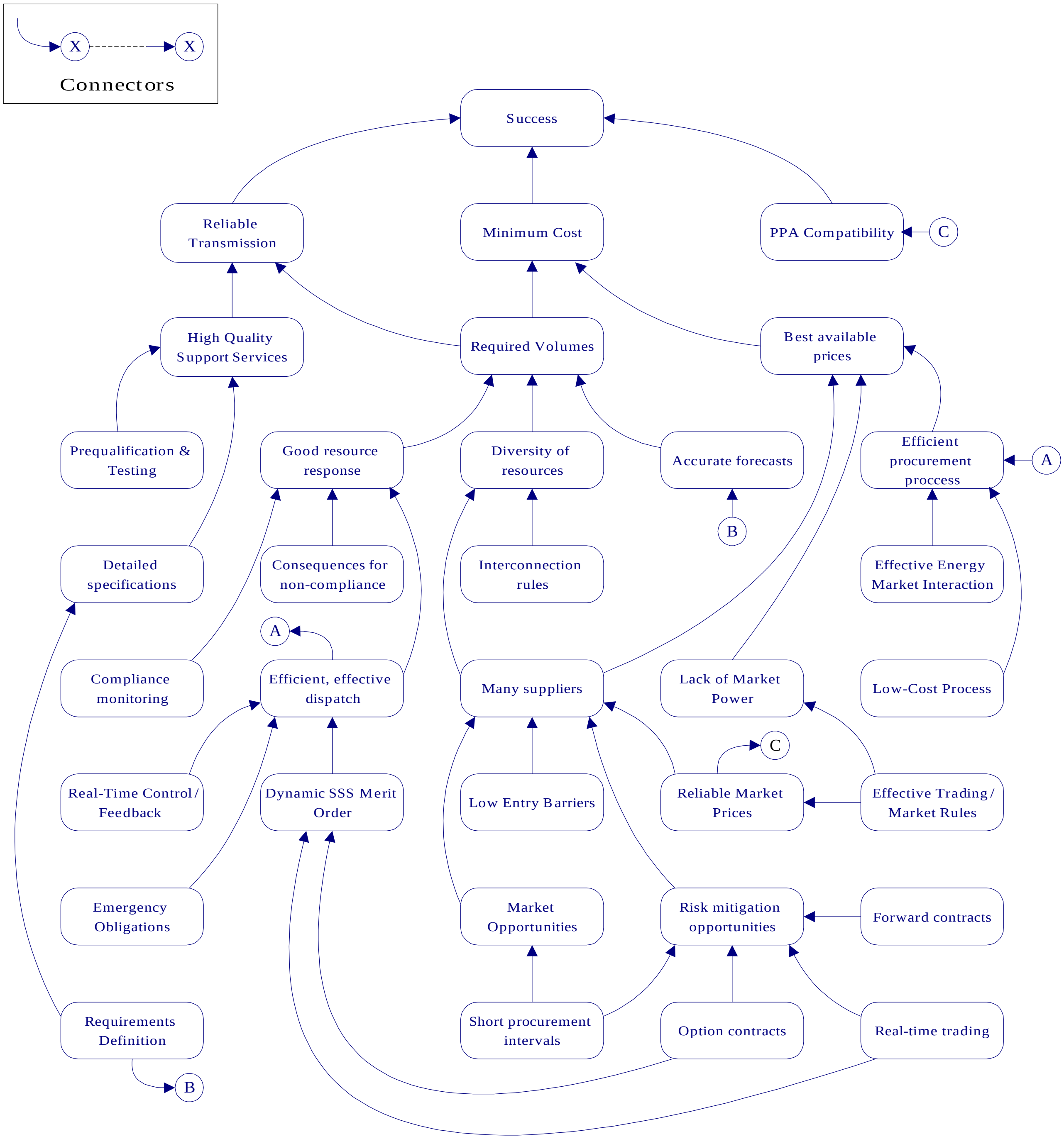

Figure 2.10: The system support services "success map."

3 THE ROLE OF THE TRANSMISSION ADMINISTRATOR

Section 26(d) of the *Electric Utilities Act*[15] states that the Transmission Administrator shall

> *set reasonable standards and requirements for ancillary services and make prudent financial arrangements so that ancillary services are available and shall ensure that those financial arrangements are carried out.*

A review of this section can help provide an understanding of the Transmission Administrator's role with respect to ancillary services. *(The reader is reminded to refer to Section 8, following the proposed ancillary services market design in Section 7, for the responses to questions raised in this section.)*

3.1 Reasonable Standards and Requirements

Section 1(1)(cc) of the Electric Utilities Act defines ancillary services to be those services required to ensure that the interconnected electric system is operated in a manner that provides a satisfactory level of service with acceptable levels of voltage and frequency stability and harmonic content. The *Act* establishes the Transmission Administrator as the party responsible for setting reasonable standards and requirements for those services. The standards and requirements are evident, or must be reflected or managed, in several contexts that have already been discussed, including:

- Specifying technical requirements for connecting to the transmission system.

- Specifying performance and other technical standards, as well as commercial and legal requirements, in applicable contracts associated with ancillary services provision. These contracts, which are being or will be developed in consultation with potential suppliers and interested parties, will be the foundation for future arrangements for ancillary services, whether they are acquired through requests for proposal, standing offers, exchange-based trading, or some other mechanism.

- Pre-qualifying and periodically testing facilities nominated to deliver ancillary services, and monitoring their compliance with dispatch instructions on an ongoing basis.

- Establishing the quantities of each ancillary service necessary to maintain the reliability and integrity of the transmission system. As already noted, these levels are established based on the professional judgement of ESBI Alberta Ltd.'s engineering staff, with due regard for the minimum requirements established by NERC and WSCC.

3.2 Prudent Financial Arrangements

That the Transmission Administrator has the responsibilities discussed above is generally accepted. There may be, however, a greater diversity of stakeholder views with respect to "prudent financial arrangements." There are a number of questions—relating to things like procurement strategies, risk, forecasting, and Transmission Administrator independence—that must be answered so that ancillary services procurement strategies for 2001 and beyond can be developed.

➢ *Should the Transmission Administrator engage in fixed-price forward purchases of ancillary services?*

The Transmission Administrator already engages, in a loose sense, in forward purchases of ancillary services, since arrangements are in place with the regulated generators to provide them as needed. However, volumes are not specified in advance and the bulk of the payments are index-based, the indexes being the pool price and (in some cases) variable unit obligation prices.

Not using fixed-price forward contracts means that ancillary services will continue to be purchased (essentially) in real time. There will be no forward price discovery, and the Transmission Administrator—and its customers, through the tariff—will assume the financial risks associated with typically volatile real-time prices. Further, either ancillary

[15] The *Transmission Administrator Clarification Deficiency Correction Regulation* (A.R. 41/99, 1999 February 17) states that Section 26(d) of the Act is to be interpreted as if it reads the way it is written here.

services suppliers or the Transmission Administrator will bear the risk of having to find alternate supplies, at real-time prices, to replace those that may be unavailable due to a plant outage or similar circumstance.

An answer of “yes” to the above question also has implications. Forward purchases may reduce the volatility of ancillary services costs and aid in price discovery, but several new questions arise immediately. For example:

- *What fraction of forecasted volumes should be procured in advance?*
- *What is an appropriate mix of contract periods?*
- *How are differences between contracted and actual volumes accounted for, both in aggregate and for individual suppliers?*
- *What implications will forward purchases have on the development of a market?*
- *Should the Transmission Administrator act as a market maker?*
- *If contracted volumes exceed actual requirements as a result of forecast error, can the excess be turned back into the energy market, and if so, who receives the proceeds from the energy sales?*

- *What role should the Transmission Administrator play in the development and operation of an ancillary services “market?”*

The Transmission Administrator could assume a number of different roles in the ultimate development, if any, of an ancillary services market. At one end of the spectrum is the “hands off” approach, in which ESBI Alberta Ltd. procures ancillary services through non-market approaches and allows others to develop a market, at their own financial risk, if there is sufficient demand. At the other end of the spectrum is a scenario in which the Transmission Administrator designs, develops, and operates the market.[16] There are many possibilities in between, including one in which the Transmission Administrator is a facilitator and major market participant, but leaves the market development to others.

[16] This includes the possibility that some other entity could be subcontracted to operate the market.

4 PROCUREMENT OPTIONS

Many options exist for the procurement of ancillary services. In fact, because of the disparate characteristics of the various services, it is likely that more than one model will be used. For discussion purposes, the models have been grouped into three classifications: market, non-market competitive, and non-competitive. *(The reader is reminded to refer to Section 8, following the proposed ancillary services market design in Section 7, for the responses to questions raised in this section.)*

4.1 Market-Based Procurement

A market-based procurement process would probably rely on some form of exchange through which contracts to provide various ancillary services could be bought and sold. The exchange would likely operate physical spot and day-ahead markets, and could also offer physical and / or financial forward contracts and perhaps more exotic instruments like options. The exchange operator would establish the ancillary services merit order based on the open contracts, and would pass that merit order to the System Controller for dispatch. Market-clearing prices would be established.

There are several advantages of a market-based procurement process:

- It provides the best price discovery, and therefore the most reliable prices for use in the hydro PPAs.
- It leads to the most dynamic merit order, and therefore to the best match between requirements and actual procurement, and to the best ability to adjust for forecast errors.
- It provides the most adaptability to prices in other markets (e.g., gas, electric energy), to plant outages, and to other system events.
- It provides the most sophisticated risk management opportunities to both buyers and sellers, as discussed above in conjunction with futures and options contracts.
- As a result of the model's short procurement intervals and relatively low entry barriers, the number of market participants—and therefore the number of resources available to provide ancillary services—is likely to be higher than under the other options. The increased number of suppliers also follows from the more sophisticated risk management alternatives.

As a result of these advantages, the market-based procurement option may be the most economically efficient one, at least for those services that are amenable to competition.[17] With the flexibility of this option comes, however, what will likely be the most complex and costly development and implementation process. The infrastructure needed for trade tracking, merit order construction and communication, settlement, and billing will have to be built and maintained. Compliance and market monitoring activities will also be required. Even if the up-front costs can be managed, such a procurement model will still only make sense if the market can provide sufficient liquidity to justify the effort.

- ➢ *For what ancillary services, if any, is the market-based approach the best one? Should priority be placed on market-based procurement for certain services?*

- ➢ *What should be done to ensure that there are enough participants and that the market is sufficiently liquid? (e.g., Should market participation be mandatory, at least initially?)*

- ➢ *How important is it to have forward contracts and/or option contracts?*

- ➢ *Is secondary trading (that is, trading that does not involve the Transmission Administrator) a critical factor in the market?*

- ➢ *Is real-time (or near-real-time) trading necessary?*

- ➢ *What other risk mitigation options exist, and how critical are they to a successful market?*

- ➢ *What is the appropriate timing for the implementation of market-based acquisition of ancillary services, and what should the transition arrangements look like? Should there be a pilot (test) market first?*

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[17] As discussed later, some ancillary services are not amenable to competition, and market-based trading is unlikely to result in any benefits for stakeholders.

4.2 Non-Market Competitive Procurement

A non-market competitive model would use monthly, quarterly, or other-duration contracts that ancillary services providers would bid on, likely through a request for proposal (RfP) procedure.[18] Contracts as short as hourly *might* be viable if an automated bid process can be established. Long-term contracts (5, 10, or even 20 years) may be useful for very localized services (e.g., reactive power) or for services where the savings from frequent competitions may be outweighed by the costs. An example of the latter is black start, which is used infrequently, requires extensive operational planning, and has a high set-up and maintenance cost relative to the likely benefits of market-based procurement.

The two major advantages of this model over the market-based model are its relative simplicity—and therefore lower up-front cost—and the flexibility of the contracts. The latter advantage arises because the contracts in a market-based model have to be relatively uniform to ensure tradability among all market participants. A major disadvantage is the potentially high administration cost that results from ongoing RfP development and evaluation. Also, the relatively longer procurement intervals commonly associated with RfPs and the less sophisticated risk management options may result in fewer participants than market-based options.

- *For which ancillary services, if any, is this the most appropriate procurement model?*

- *Would competitive, non-market approaches meet the requirement for reserves pricing for the hydro PPAs?*

4.3 Non-Competitive Procurement

Non-competitive procurement *may* be required for ancillary services that are either not competitive by nature or for which market power may exist. In such cases, direct contract negotiation, tariff-based obligations, terms and conditions of transmission connection, or even regulatory intervention may be required. Several examples (e.g. emergency conditions, ±0.9 power factor) have already been mentioned. The advantage of this approach is that it can be quite simple and reliable. However, it is not in keeping with the philosophy behind industry restructuring and would be used by the Transmission Administrator as little as possible.

- *What ancillary services, if any, should be procured in this way?*

[18] EAL's standing offer for reserves from curtailable load is an example.

5 MARKET DESIGN AND OPERATIONS ISSUES

There are many questions that must be addressed in developing processes for acquiring ancillary services. Some of the questions are of a general nature. Others are related to more specific topics, such as the interaction of the ancillary service procurement processes with the energy market, setting ancillary service prices, and defining the nature of participants' obligations. *(The reader is reminded to refer to Section 8, following the proposed ancillary services market design in Section 7, for the responses to questions raised in this section.)*

5.1 General Questions

All of the ancillary service procurement options available post-2000 will require the design, development, and implementation of acquisition processes and systems. Clearly the complexity thereof is a function of the procurement model(s) chosen, but some effort will be required in all cases. There are several questions of a general nature that must be answered before this development and implementation can proceed.

- *Who should initially develop the market, and what development model should be used?*

Several market development options exist. At one extreme the Transmission Administrator would assume complete responsibility for design, development, implementation, and operation. Detailed specifications would be issued and a systems developer would be selected through an RfP. At the other extreme is "laissez faire," wherein the Transmission Administrator waits for a market to be developed by one or more private operators. A middle-ground option could have the Transmission Administrator facilitate market development by a private market operator by, for example, agreeing to act as a market maker for some period. There are many other possibilities.

- *How should the development be funded and how should the costs be recovered?*

Here, too, many options exist, though the final choice will be driven by the answer to the previous question. If the Transmission Administrator is responsible for development, an obvious possibility is for the funding to come through the transmission tariff. Alternatively, there may be parties willing to fund the initial development on the prospect of making a return on investment through something like a trading charge.

- *Who should operate the market on an ongoing basis?*

The possibilities here include the Transmission Administrator, an independent market operator, or the Power Pool of Alberta.

- *Will market participants be allowed to provide their own ancillary services?*

In the United States, the Federal Energy Regulatory Commission allows transmission customers to provide at least some of the ancillary services associated with their energy transactions. While self-provision is primarily a tariff issue and should be dealt with in that context, it has a direct bearing on the answer to the next question.

- *Will the Transmission Administrator be the sole buyer?*

Section 26(d) of the *Electric Utilities Act* makes the Transmission Administrator responsible for making prudent financial arrangements for ancillary services. Does this necessarily imply that the Transmission Administrator would be the sole buyer in a market? Would a legislative change be needed to allow multiple buyers? This issue is an important one because markets tend to be most effective when there are many sellers *and* many buyers.

- *How can ex-Alberta entities be encouraged to participate in the market?*

- *Will the ancillary services market be "suitably competitive?"*

A "suitably competitive" market is one in which no single party or small group can consistently manipulate the market to its advantage. Whether Alberta will have a competitive ancillary services market will depend on a number of factors, including the outcome of the upcoming auction of the Power Purchase Arrangements (PPAs).

5.2 Interaction with the Energy Market

Many of the resources that are used to supply ancillary services are the same as those used to produce energy. The need to have ancillary services can result in an increase in the amount of energy available to the energy market (e.g., units constrained *on* for spinning reserve), but more often it decreases available energy (e.g., units constrained *down* for spinning reserve). Many questions therefore arise about how energy and ancillary services are dispatched. There are many possibilities, including dispatching for ancillary services and then for energy, dispatching for energy and then for ancillary services, and dispatching based on a simultaneous optimization. Clearly there should be a strong link between energy and ancillary services prices, but whether that link is a formal one established through market rules, or an informal one driven by the market itself, is but one of many open questions.

- *Regardless of the acquisition method(s), should the prices for ancillary services be tied formally to prices in the energy market?*

There are several ways in which prices could be formally linked. The current arrangement, wherein generators are paid opportunity cost, provides one example. Another possibility is that a market offer could employ a pool price multiplier or differential to establish the price. Note that if ancillary services prices are formally linked to energy prices, the Transmission Administrator and its customers will be taking the risks associated with energy price volatility, while if prices are based on suppliers' fixed-price offers, it is the suppliers who will be taking that risk.

- *What will the energy market look like, and to what extent does its final form affect ancillary services procurement?*

- *How closely can the energy and ancillary services dispatch processes be linked? Should an attempt be made by the System Controller to simultaneously optimize the energy and ancillary services dispatches, or should they be kept separate?*

- *Can an* ex ante *reserves market coexist with an* ex post *energy market? What is required to make it work, and should it even be attempted?*

- *What is the impact on ancillary services pricing and dispatch of price/volume restatements in the energy market?*

- *How closely should ancillary services procurement methods be tied, in a systems sense, to the operation of the Power Pool? That is, is it necessary that potential suppliers be able to make ancillary services and energy offers through the same system?*

- *Will arbitrage occur between the energy and ancillary services markets, and if so, will that arbitrage be beneficial or detrimental to the markets?*

5.3 Ancillary Services Pricing

In addition to the pricing-related questions that arise when discussing the interaction of the energy and ancillary services markets, there are several that arise in a more general context.

- *What is the longest price interval (weekly, daily, daily on/off peak, etc.) that is compatible with the hydro PPAs?*

- *Would it be possible to derive shorter-interval prices from longer-interval ones? For example, could one use weekly ancillary services offers plus some other inputs to derive an hourly ancillary services price?*

- *Should reserves prices include both availability payments (i.e., payments for being "on call") and utilization payments (payments for actually being dispatched)? If so, how should the prices in the hydro PPAs be established?*

- *Is the process in which all suppliers offering less than the market clearing price receive that price advisable? How would such a mechanism work if suppliers could offer different combinations of availability payments and utilization payments?*

- *Is the equilibrium model, the bid/offer-matching model, or some other model the most appropriate one for the ancillary services market?*

- *Should prices be set* ex post *or* ex ante*?*

- *Should there be a cap on ancillary service prices as there is on energy prices? If so, what is the appropriate value?*

- *If ancillary services are priced against an index, what is the most appropriate index?*

5.4 Participant Obligations

A critical issue in the design and operation of the ancillary services market is the nature of the obligations on the participants. As discussed in Section 2.3, it is important to have a good resource response to directives from the System Controller; otherwise, the transmission system could be put at risk. Consequently, it would seem that the consequences of a failure to deliver should be quite severe. On the other hand, obligations that are too onerous will dissuade many potential suppliers from entering the market and increase the risk premiums charged by those who do enter. For their part, suppliers want assurances that they will be compensated fairly for the services they provide. The following are some relevant questions.

- *Should participation in the ancillary services market be mandatory or voluntary?*

Mandatory participation can, in theory, improve liquidity in a market. However, there are usually many ways to circumvent the rules, and enforcement can be difficult.

- *Are offers to provide ancillary services binding or non-binding? What about bids to buy?*

- *What should the consequences for non-performance be, and what events should constitute* force majeure*?*

These two questions are closely linked. The possible consequences for non-performance range from none at all (non-binding obligations), through replacement cost coverage, to replacement cost coverage plus penalties. For example, it has been suggested that defaulting suppliers be required to pay some portion of any penalties levied on the Alberta control area by the Western Systems Coordinating Council.

- *Should the contracts be physical or financial, and is the difference meaningful?*

A physical contract is one that calls for the actual delivery of some commodity. A financial contract settles with an exchange of cash instead of a transfer of the commodity, with the settlement amount being determined in relation to some price (e.g., the spot price) associated with the commodity.[19] As long as there is ample supply, the two contract types are equivalent, since the financial buyer can acquire the commodity in the spot market and receive or pay the difference between the contract and spot prices. In the case of supply shortages, however, the physical buyer gets the commodity while the financial buyer may receive only cash. Cash settlement may be inadequate to cover the buyer’s cost of lost production. The existence of convenience yield in commodity markets and occurrences of involuntary load shedding both provide evidence that suppliers and transportation systems cannot always deliver additional amounts of a commodity rapidly enough to avert supply shortages.

- *Should unit commitment in respect of ancillary services be the responsibility of the System Controller or the generators themselves? That is, is unit self-commitment appropriate?*

Self-commitment means that the generator owners are responsible for ensuring unit availability, even if that means starting the unit well in advance of the time of its delivery obligation. The other option is that the System Controller makes unit commitment decisions, which often means that generators are entitled to some form of payment other than that specifically for the provision of the contracted service (e.g., start-up costs).

- *Should the Transmission Administrator be obligated to buy the required volume of ancillary services regardless of the price? If not, what is the appropriate tradeoff between reliability and cost?*

[19] There are several variations on this basic theme.

6. ANCILLARY SERVICES ACQUISITION PRINCIPLES

Based on its own views and extensive feedback from stakeholders, ESBI Alberta Ltd. has established the following principles for the acquisition of ancillary services in 2001 and beyond.[20]

1. The requirements for ancillary services in Alberta will be guided by the policies of the North American Electric Reliability Council (NERC) and the Western Systems Coordinating Council (WSCC), as may be amended by the Transmission Administrator to account for local circumstances.

2. All physical resources from which ancillary services are to be delivered, and the processes that cause that delivery to take place, must be pre-qualified in accordance with the Transmission Administrator's technical requirements. The resources and associated processes may be tested periodically to ascertain their ability to meet specified performance criteria.

3. ESBI Alberta Ltd. will purchase power system restoration (black start), reactive power, and voltage support services through requests for proposal and / or direct negotiations with potential suppliers, as appropriate to each situation.

4. Regulating reserve, load following, spinning reserve, and supplemental reserve will be procured through the daily (or more frequent) submission and acceptance of offers. Services may be added to or deleted from this list in response to changes in ancillary service requirements.

5. The Transmission Administrator will consider entering into forward arrangements for ancillary services where it is prudent to do so, competition is enhanced, and all technical requirements can be met.

6. The Transmission Administrator will disclose ancillary service prices, volumes, and contract terms to an extent consistent with disclosure in other open, competitive markets, or to such other extent as may be dictated by legal or regulatory considerations.

7. The Transmission Administrator will work with the Power Pool of Alberta to ensure that the security, reliability, and economic efficiency of the interconnected electric system are properly addressed in the design and operation of ancillary service procurement processes.

8. Nothing in this proposal precludes a third party from providing an alternative to the procurement methods developed by the Transmission Administrator. ESBI Alberta Ltd. will consider procuring some or all ancillary services through such an alternative if its service providers are so willing.

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[20] These principles were presented in a letter from the Transmission Administrator to the Alberta Energy and Utilities Board dated 03 March 2000.

7. MARKET DESIGN RECOMMENDATIONS

The section presents the recommended ancillary services market design. As noted previously, the market is intended to provide the Transmission Administrator and others with the opportunity to acquire regulating reserve, spinning reserve, supplemental reserve, and load following within an open and competitive environment. The market should be implemented—at least on a pilot basis—by the fourth quarter of 2000 to provide participants with an opportunity to understand market mechanics and obligations in advance of 2001 January 1. Interaction with existing suppliers, potential PPA Buyers, transmission customers, and potential market operators will be an important part of the development of the market's business rules, contract terms and conditions, trading mechanisms, and settlement systems.

· Participants

The key components of the ancillary services market are shown in Figure 7.1. The first of these is the set of market participants.

The primary buyer of ancillary services, and the entity to which the services will be physically delivered, is the Transmission Administrator. However, any seller can also be a buyer in order to close out or cover an existing position. The fact that suppliers can also be buyers creates a market interaction that will help to prevent prices from moving too dramatically in either direction, and will add to the liquidity of the market. Potential suppliers of each of the ancillary services must meet the Transmission Administrator's technical requirements, which will be set out in the appropriate technical documents in due course.

· Contracts

The contracts to be traded are shown in Figure 7.2. Each tradable instrument will be for the physical delivery of a contracted volume of ancillary services over a single delivery hour. There will be two forms of each contract, one for the "active" market and one for the "standby" market. The first form has fixed-price and index-price sub-forms.

Once a supplier's active service offer has been accepted, its resource *will* be dispatched by the System Controller to provide the contracted service.[21] If its standby service offer is accepted, the supplier *may* be dispatched. In effect, a standby supplier sells a call option for the contracted service.[22] The standby queue could be considered a quasi-real-time market, the objectives of which are to: (1) replace active-market suppliers that are subject to forced outages themselves; (2) replace active reserves that that are deployed in response to a contingency and that for some reason cannot be restored to a reserve-providing state (e.g., a load that has a minimum down time); (3) provide additional resources in the event that inadequate volumes are purchased by the Transmission Administrator in the days-ahead market—a possible result of forecast error; and (4) allow suppliers of ancillary services to purchase options as hedges against their potential inability to deliver.

[21] It is possible that the supplier's service would not be called, but only in the case where the Transmission Administrator has over-forecast its requirements. Regardless of whether the supplier is actually dispatched, the contract remains binding on the Transmission Administrator and the supplier will be paid according to the terms of the contract.

[22] Note that a supplier can be in the energy market while it is in the standby state. Once moved to the active state by the System Controller, capacity contracted to the Transmission Administrator must be made available for ancillary services.

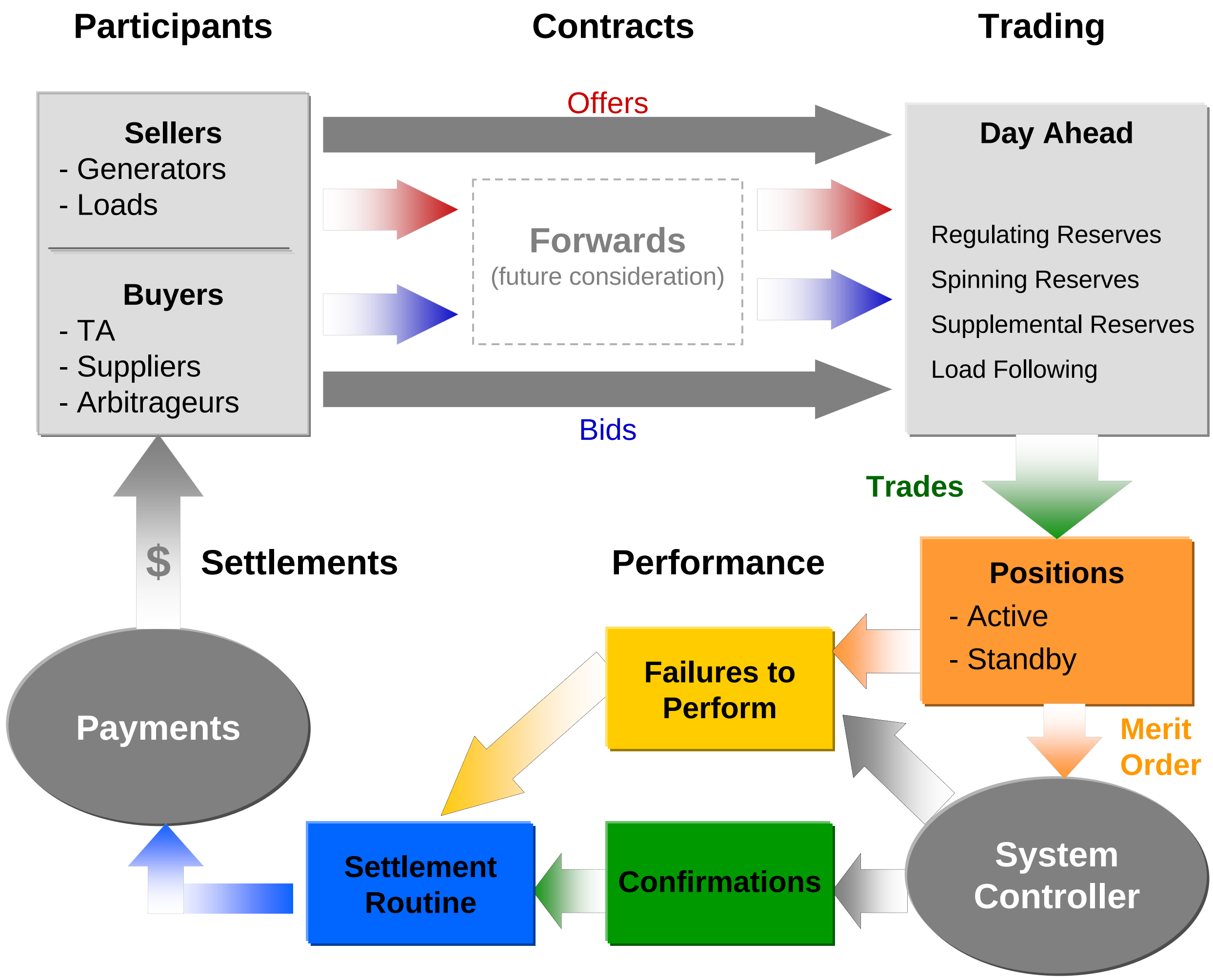

Figure 7.1: The basic structure of the ancillary services market.

As noted above, the active market provides two pricing alternatives: bids and offers as fixed prices and bids and offers as premiums or discounts to a defined index. The index anticipated for such settlements is the day-ahead energy price. This will allow suppliers to offer services at a discount or premium to the energy market without having to guess at energy prices. The index-price option allows suppliers to, in effect, declare their indifference between the energy and ancillary services markets.[23]

Standby contracts have some of the features of an option contract. Buyers have the right, but not the obligation, to call on the sellers to provide services. The bids and offers for standby contracts will include two price components, as shown in Figure 7.2: one for acquiring the right to call for the service (the premium), and a second as payment for actually providing the service if activated (the activation price). The determination of suppliers for standby service will be based on a probability-weighted combination of the two prices, where the probability is the Transmission Administrator's estimate of the likelihood that the service will be called.[24] Once a supplier has entered the standby queue, the premium becomes a sunk cost to the Transmission Administrator and actual dispatch, if required, will proceed from lowest to highest activation price.

[23] It is not a given that a supplier will be indifferent to the delivery of ancillary services or energy. For some resources (e.g., run-of-river hydro), fuel limitations may create a preference for the latter, while co-generation facilities with steam hosts may have a preference for the former. The market may eventually express a preference for one form of pricing over the other.

[24] A brief discussion of this topic is given in Section 7.3.3, and an example is provided in the response to Question 8 in Appendix B.

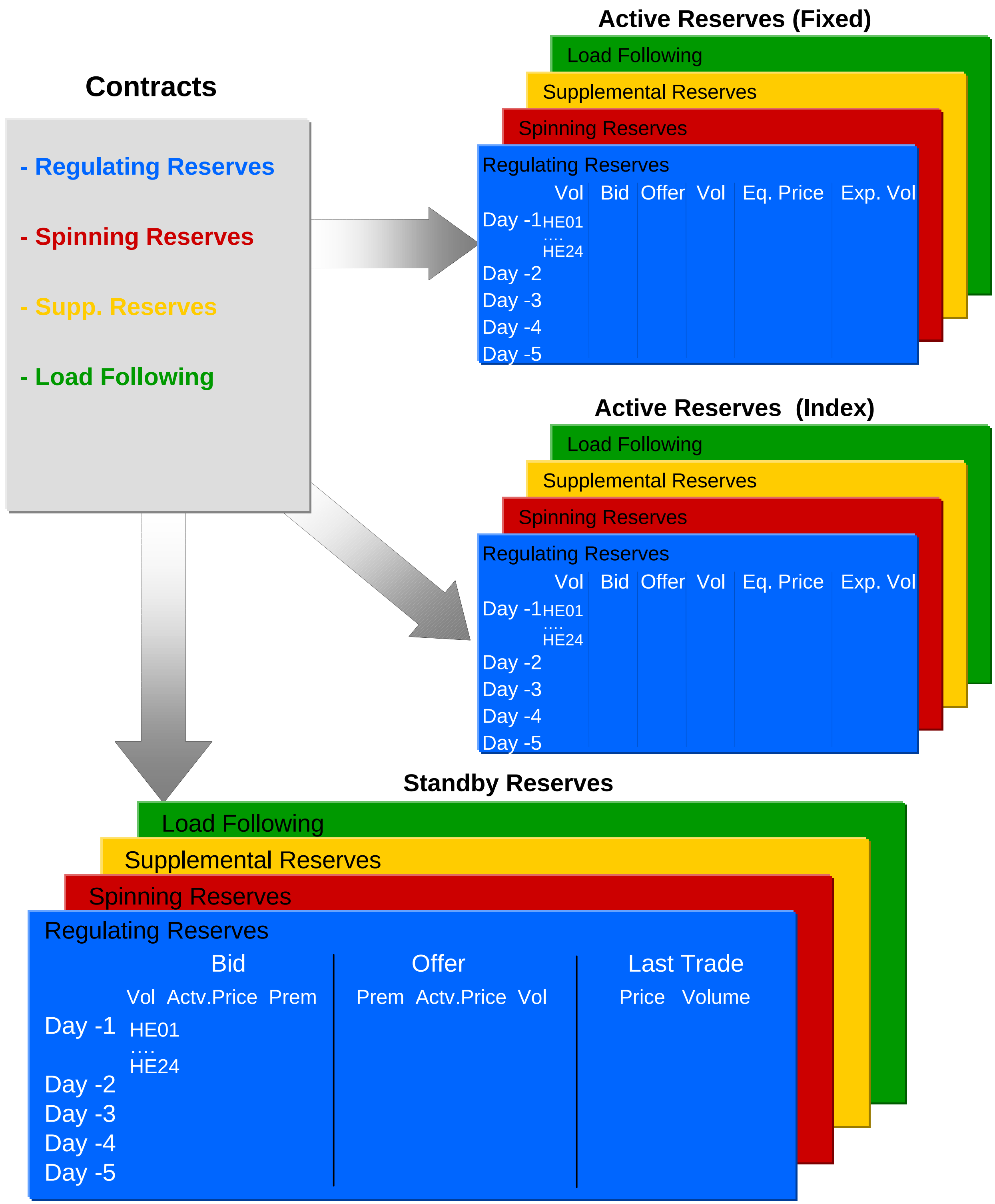

Figure 7.2: Ancillary service contract forms.

- **Trading**

i. General Considerations

The ancillary services market will be operated during regular business days from 08:00 until 16:00.[25] Instruments applicable to each delivery day—including weekend days and statutory holidays—will be available for trading during each of the five preceding business days. At each daily close of the market, suppliers and the Transmission Administrator will be notified of all deals, and new prices will be established.

Market closings for all but the final trading day for each delivery day will be at 16:00. Traded positions from all sessions are firm and must be met by performance, by trading out of the positions in subsequent trading sessions, or by substitution of supplier by the obligated party through notice to the System Controller. Such notice may be provided until one hour prior to the hour of delivery. Any lack of performance after this time will be considered a failure condition; the shortfall will be supplied from the standby queue, and all costs and penalties will accrue to the failing supplier. It is the responsibility of the supplier to meet any prerequisites—such as out-of-merit operation in the energy market—necessary to meet its obligations.

Each day will contain 24 hourly instruments designated HE01 (hour ending 01:00) through HE24 (hour ending 24:00). Each of the hours in the delivery day can be traded as discrete instruments. Alternatively, buyers and sellers will be able to submit block orders covering a range of hours (e.g., off-peak hours) within which they prefer to purchase or sell a service. The orders can be linked such that the acceptance of an offer for a higher-quality service automatically removes the offer for a lower-quality service. Resolution of services will follow the closing of the energy market, and will be in the following order: regulating reserve, spinning reserve, supplemental reserve, and load following.[26]

By way of example, the trading of instruments from HE01 through HE24 for Friday, September 1 would begin on Friday, August 25 (Day-5) and continue through Thursday, August 31 (Day-1). Since weekends and holidays are traded on the same cycle as the preceding business day, the instruments for Saturday, September 2 through Monday, September 4 (Labour Day) will trade at the same time. Market timelines are shown in Figure 7.3.

ii. The Active Market

The active market contains both fixed-price and index-price instruments. The former give sellers the option to seek fixed returns for their services, while the latter allow sellers to tie their prices to electrical energy prices. The index proposed is the close-of-market day-ahead energy price for the delivery hour. It is anticipated that the day-ahead energy market will close for all hours of the upcoming day at the same time. The active-market instruments for the *next* day (i.e., the instruments traded as Day-1) will close two hours after the energy market (expected to be 12:00, assuming an energy market close at 10:00). This will provide sufficient time for suppliers to interact with the spot energy market for the corresponding delivery day after their ancillary service commitments have been determined.

The active service's fixed and index prices will be established using equilibrium pricing. Equilibrium pricing allows sellers and buyers to enter offers and bids at any time while the market is open. It sets a market-clearing price for each service at the close of trading, matching all bids greater than, and all offers lower than, the price that maximizes the volume traded. Because the price is set only at market closing, sellers can place offers, and the Transmission Administrator and other buyers can place bids, and not be concerned about monitoring the market all day. Thus, competitive pricing can be achieved without requiring 7×24 staffing in a relatively low-volume market.

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[25] All market times discussed in this document are indicative. Final decisions will be made during the detailed market design process and will be made with due consideration of the relationship to other markets (such as the day-ahead energy).

[26] The location of load following in the closing order has not been finalized.

Day-5:	08:00 - 16:00	*Active & Standby Markets Open*
Day-4:	08:00 - 16:00	*Active & Standby Markets Open*
Day-3:	08:00 - 16:00	*Active & Standby Markets Open*
Day-2:	08:00 - 16:00 12:00	*Active & Standby Markets Open* *Nomination of Facility/Instrument* *Limit Checking & Violation Notices* *Violator Position Liquidation*
Day-1:	08:00 - 14:00 10:00 12:00 14:00 16:00 23:00	*Active & Standby Markets Open* *Day-Ahead Energy Market Closes* *Active Market closes* *Standby Market closes* *Schedules provided to System Controller* *Initial reserves for HE01 are set*
Day 0:	HE01 ... …HE24	*Active and standby services provided*
Day+1:	10:00am	*Confirmations & failure reports compiled*
Month+1:		*Meter data reviewed, payments determined*

Figure 7.3: Ancillary services market timelines.

One of the benefits of equilibrium pricing is that there is no time premium for when bids and offers are put into the market, and all trades are at the same price. The major drawback to equilibrium pricing is that it is relatively easy to manipulate prices, particularly if the buyer has to acquire known minimum levels of service. This is alleviated by employing five discrete equilibrium pricing sessions with no indication of when or what volumes the Transmission Administrator will buy.

iii. The Standby Market

Orders in the standby market will be for a specific volume and will contain both an activation price and a premium (see Figure 7.2). Trades will be based on bid/offer matching, since the equilibrium model makes it difficult to incorporate usage probabilities into buying decisions. The calculation of an *expected price*[27] enables the acquisition of standby reserves at a cost that is optimum given the probability of calling on the standby resources to replace active

[27] The term *expected price* comes from the "expected value" of a random variable in probability theory. The use of the expected price allows for the incorporation of the uncertainty about whether the seller will actually be called to provide a service. The use of probabilistic calculations (see the response to Question 8 in Appendix B for an example) is analogous to the situation in financial markets, where probability-related models such as Black-Scholes are used to price options. It is important to note that probabilities are not used in the determination of the prices paid to suppliers.

resources. That probability will be a function of system conditions and the total amount of standby reserve the Transmission Administrator has acquired. Note that, because the bid / offer model requires more active participation in the market, trading in the standby market may be narrowed to prescribed sessions at the opening and closing of the ancillary services market. The standby market for delivery the next day will close two hours later (14:00) to allow suppliers not in the active market to provide standby service.

· Contract Performance

The market operator will provide notification of obligations in sufficient time for suppliers to meet those obligations and to determine their strategies for the spot energy market. The System Controller will issue dispatch instructions to utilize the services as contracted in the active market. If a standby resource is activated then notice of such action, along with an explanation of the event, is provided to the Transmission Administrator. If the activation was triggered by a supplier's inability to perform then a failure condition exists and costs and penalties may be applied as part of the settlement process.

As noted in Section 2.2, it is the Transmission Administrator's intention to pre-qualify and, where necessary, periodically test suppliers and their delivery processes for compliance with technical requirements. In addition, a compliance monitoring process will be established to continually review the response of ancillary service providers to dispatch directives. If any response encountered during testing or operations is found to be outside the bounds established in the contract specifications, there will likely be financial and / or other consequences for the supplier. The most obvious consequence is that a party that fails to deliver on its operational obligations should be required to pay any additional costs incurred by the Transmission Administrator in making up for the shortfall. Other consequences could include an assessment of penalties and, ultimately, removal from the list of approved ancillary service suppliers.

Clear definitions of failure conditions, *force majeure*, remedies and penalties, and dispute mitigation mechanisms—for both test-induced and operational failures—will be included in the standard contract terms and conditions. While the definitions have not yet been established, they will be guided by the principle that the consequences for failure to deliver must be onerous enough to prevent suppliers from benefiting from such a failure, but not so onerous that they discourage participation in the market.

i. Conversion to "Energy Contracts"

To determine the attributes of the instruments that the ancillary services market should trade, consideration was given to the impact of those attributes on the pricing of the services, the nature of the interaction between the ancillary services and energy markets, and the role of each service in system operations. During discussions with stakeholders the following question arose: should ancillary services, particularly spinning reserve, be freely convertible to energy in circumstances other than those for which the services are specifically designed?[28] The question is addressed below in the context of spinning reserve; similar (though not necessarily identical) considerations apply to the other services.

At one end of the spectrum lies a situation in which spinning reserve is freely convertible to energy at the option of either the Transmission Administrator or the System Controller. The conversion may be unrelated to a system contingency; for example, it could be driven by economics, the idea being that the reserve-providing unit could displace a more expensive unit from the energy merit order. However, if spinning reserve is convertible to energy by either the Transmission Administrator or the System Controller under non-contingency circumstances, the same option must be made available to other market participants as well. This means that a spinning reserve contract can be used as a substitute for an energy contract. Given that a spinning reserve provider should be able to save the fuel that would otherwise be consumed to produce energy,[29] the Transmission Administrator has a desire to see a discount related to that fuel saving in the spinning reserve offers. However, if spinning reserve is freely convertible to energy, then suppliers cannot count on this cost saving and would not be expected to price spinning reserve at a discount.

At the other end of the spectrum lies a situation where spinning reserve is not convertible to energy under any circumstances. The inference is that the Transmission Administrator's full complement of reserve will remain active even if firm (non-recallable) load is being curtailed. This outcome is highly undesirable, since it makes no sense to maintain "insurance" against the loss of firm load while simultaneously shedding that load. Current practice is to decrease spinning and supplemental reserve levels to avoid shedding firm load, and the Transmission Administrator

[28] The whole purpose of each ancillary service is to produce, to consume, or to stop consuming energy in specific circumstances. For example, units providing regulating reserve must increase their energy output in response to AGC signals, while spinning reserve units must increase energy output in response to a contingency.

[29] When called to provide energy in response to a contingency, reserve suppliers will receive pool price for their output.

supports this procedure.[30] From a contract design perspective, it is necessary to permit the System Controller to increase the energy available for firm load under certain circumstances.

There are two basic ways in which it may become necessary for firm load to curtail its demand for energy. The first occurs as a result of a contingency that decreases the available supply. In such a circumstance, firm load curtailment is minimized when both supplemental reserve and spinning reserve resources are dispatched to provide energy,[31] but only if those resources are not replaced with resources from the standby queue. Such replacement would have the impact of reducing energy availability from those standby market participants that are in the energy market at the time of the contingency. The Transmission Administrator expects to create an operating procedure that provides the System Controller with the ability to *not* replace dispatched reserves when activating supply from the standby queue would cause firm load to be curtailed.

The second situation is that in which the threat to firm load results not from a contingency affecting supply in or near real-time, but rather from demand rising to the point it cannot be supplied at prices below the energy price cap. Defining the reserve service such that the System Controller can dispatch certain quantities of reserve to avoid firm load curtailment, even though such curtailment is not a result of a supply contingency, is desirable. This can easily be accomplished by dispatching reserve once real-time *energy* prices reach the *reserves* price cap for each of the reserve services.[32] With this method of providing convertibility from reserves to energy, reserve providers are affected by a severely supply-constrained system, just as they would be affected by a supply-side contingency. Generators providing reserve would receive the real time energy price (at or near the reserves price cap), and load providing reserve would be curtailed.

The following table summarizes the foregoing discussion

[30] Note that regulating reserve is maintained even in the face of curtailing non-recallable load. Regulating reserve is required to maintain system control and avoid major system disturbances.

[31] Loads supplying supplemental reserve "supply" energy by decreasing their consumption.

[32] The intent is to allow the release of reserves when energy supplies have been exhausted and the next option available to the System Controller would otherwise be the curtailment of firm load. It is assumed that, under such circumstances, energy prices would rise to the reserves price cap, though energy market rules could conceivably allow a different pricing outcome.

Table 7.1: Conversion of Reserves to Energy

	Pure Reserves	**Reserves Convertible to Energy at Buyer's Option**	**Reserves Convertible to Energy at the Reserves Price Cap**
Description	Limited single- purpose service to mitigate supply side contingency	Multipurpose energy and reserves contract • Can be used to manage Transmission Administrator reserves portfolio mismatches • Permits other buyers to arbitrage energy and reserves prices • Used to mitigate firm load shed	In addition to mitigating supply side contingency, can be dispatched to mitigate load shedding at the reserves price cap
Seller Pricing Considerations	Price as reserve	• Price as the higher of energy and reserve opportunity cost • Should trade at a premium to energy	Price as reserve
System Considerations	Retains reserves even in the event of non-recallable load curtailment	Muddies distinction between energy and reserves	Permits reserves to be consumed to avoid shedding non-recallable load

It has been suggested that reserves should be convertible to energy in one other situation, that being the one in which the Transmission Administrator has purchased more reserves in the days-ahead markets than the System Controller determines are needed in real time. This situation would only arise when the Transmission Administrator over-forecasts the required volumes. Given that the reserves forecast error is only on the order of 7% of the load forecast error, the former are unlikely to be very large. However, to avoid frequent over-purchase situations, the Transmission Administrator may consider purchasing slightly less than its forecast requirement (say, 95% of it) in the days-ahead market, allowing the standby queue to make up the shortfall. Actual market experience will lead to refinements of the Transmission Administrator's purchasing practices.

· Settlement

The settlement of active-market trades will be at the traded prices and contracted volumes. The prices paid will be as traded for fixed price deals, and priced to index for index deals. In the standby market, suppliers will be paid their premium prices. They will receive their activation prices only if activated, that is, if they are actually called by the System Controller to provide ancillary services. An inability to meet an activation order will be considered a failure condition and will result in forfeiture of the premium and potential imposition of penalties (depending on the nature of and reason for the failure). As noted above, formal definitions of the penalties to be applied to failure conditions will be a topic during the market's detailed design phase.

Settlement will be made against the traded volumes so long as the verification against meter data indicates that the seller was within contractually allowed tolerances. If the supplier is found to be in a failure condition, due either to an inability to respond to a dispatch instruction or as a result of a spot check indicating the unit cannot perform within the contract specifications, then failure costs would include all costs to replace the service plus potential penalties. Meter data, dispatch records, availability confirmations and failure reports, along with the terms of trade, will be used to determine monthly settlements. Payment processes will include adjustments for any performance failures, penalties, gains or losses on offset positions from the days-ahead markets, and premiums for standby acquired as insurance against inability to meet obligations.

· Market Walkthrough

The following example illustrates the day-to-day interaction of a supplier with the ancillary services market. The supplier has the capability of providing up to 50 rMW of each of the four services.[33] The supplier is offering services for Friday, September 1, and enters the market on Day-4 with a set of linked orders in three different time blocks.

Table 7.2: Example Ancillary Service Offers

Offers			Service		Time	
Volume	**Attribute**	**Price**	**Type**	**Attribute**	**Start**	**End**
25	A or N	$30	Regulating	linked	HE01	HE06
50	A or N	$30	Spinning	linked	HE01	HE06
50	A or N	$25	Supplemental	linked	HE01	HE06
50	min 10	Index-$5	Regulating	linked	HE07	HE20
50	min 10	Index-$8	Spinning	linked	HE07	HE20
50	min 10	Index-$10	Supplemental	linked	HE07	HE20
50	min 10	Index-$5	Load following	linked	HE07	HE10
50	min 10	Index-$5	Load following	linked	HE18	HE20
25	A or N	$30	Regulating	linked	HE21	HE24
50	A or N	$30	Spinning	linked	HE21	HE24
50	A or N	$25	Supplemental	linked	HE21	HE24

The above orders indicate a willingness to sell regulating, spinning, and supplemental reserve in all hours.[34] The orders are linked such that if a resource is acquired for a higher-quality service then the orders for the remaining service(s) would automatically be pulled. The blocks are designated as *all or nothing* (A or N), meaning that the full volume must be taken for the entire offer period. The on-peak orders include a load-following offer for two three-hour blocks, one at the beginning of the peak period and the other at the end. All on-peak offers are index offers and are not designated as all-or-nothing; hence, partial volumes can be acquired in individual hours, with a minimum volume of 10 rMWh.

[33] The units “rMW” and “rMWh” mean “reserve megawatts” and “reserve megawatt-hours,” respectively. The notation is used to emphasize that the provision of reserve capability is not the same as the provision of energy

[34] The order screen for the ancillary services market would allow the supplier to pre-establish a grid for entry of offers with minimal re-keying of repetitive data. Generally, suppliers would have separate grids set up for weekdays and for weekends and holidays. Users could change prices, order types, link status and order size for all grid entries with single entries. On release of the grid order, individual offers with the accompanying order attributes would be placed in each of the 24 hourly instruments for September 1.

The orders shown in the above table would be placed into the offer queue for each service for each hour, and would be ranked from highest to lowest offer. The entry of bids by the Transmission Administrator or others looking to acquire ancillary services would trigger the calculation of an indicative equilibrium price and an indicative volume of trade. So long as the highest bids exceed the lowest offers then the market is capable of trading. The supplier in this example would be able to view all orders in each instrument and obtain an indication as to whether its offers are "within the market," i.e., likely to trade at the close.

The following example is a single hourly instrument for regulating reserve for HE01 on September 1, with the 25 rMWh for the example supplier highlighted:

Table 7.3: Regulating Reserves, HE01, September 1

Line	Bid Volume	Bid Price	Offer Price	Offer Volume	EQ Price	Expected Volume
1	15	$35	$20	10		
2	20	$32	$25	15	$28.50	25
3			$30	25**A**		
4	15	$25				
5	15	$20				

The above table shows four bids and three offers. The bids are queued from highest price to lowest, while offers are queued from lowest price to highest. The example supplier's order (shaded) is for 25 rMWh at $30, and has an 'A' designation indicating *all or nothing*. The equilibrium pricing mechanism would indicate a price of $28.50/rMWh for an expected trading volume of 25 rMWh. The price is calculated as the mid-point between the lowest bid and the highest offer for orders that are within the market ($32 and $25, respectively).

A total of 35 rMWh has been bid at prices higher than the $30 offer from the example supplier (lines 1 and 2). However, the supplier placed an all-or-nothing designation on the 25 rMWh order, and there are two offers totaling 25 rMWh (also lines 1 and 2) that will be taken first. Therefore, 10 rMWh of demand at prices higher than $30 cannot be served. If the market closed with no other adjustments, then 25 rMWh would trade and the supplier would not sell any regulating reserve for HE01 of September 1 on Day-4 (August 28). The supplier can look to three alternatives:

- Alternative 1, do nothing. As this was a linked order into the spinning and supplemental markets, the supplier could determine if it would trade in these markets, or wait until later in the Day-4 session, or hold out until one of the last three sessions.

- Alternative 2, alter an attribute. The supplier could remove the all-or-nothing attribute and allow 10 rMWh to trade. The equilibrium price would move up to $31 (the midpoint of the $32 bid and the $30 offer) as shown in the following table.

Table 7.4: Regulating Reserves, HE01, September 1
(all-or-nothing attribute removed)

Line	Bid Volume	Bid Price	Offer Price	Offer Volume	EQ Price	Expected Volume
1	15	$35	$20	10		
2	20	$32	$25	15		
3			$30	25	$31	35
4	15	$25				
5	15	$20				

In this instance another supplier entering a volume at less than $30 would reduce the volume that the example supplier would sell.

- Alternative 3, change the offer price. The supplier could reduce the offer price to $25 and sell all 25 rMWh at the equilibrium price of $25, as follows:

Table 7.5: Regulating Reserves, HE01, September 1
(new offer price)

Line	Bid Volume	Bid Price	Offer Price	Offer Volume	EQ Price	Expected Volume
1	15	$35	$20	10		
2	20	$32	$25	15		
3	15	$25	$25	25**A**	$25.00	50
4	15	$20				

In this case, if another supplier entered a price less than $25, then the supplier could once again be bumped from the market.

To continue with the example, it is assumed that the supplier chose Alternative 3 and reduced its price to $25/rMWh, and that the Day-4 session closed with no other changes. At the close of the regulating market, the orders in the spinning and supplemental markets would immediately be reduced by 25 rMWh because these orders were linked. Note that the regulating markets for HE02 to HE06 must also be capable of trading the 25 rMWh—again because this was an all-or-nothing block order for all six hours. For this example, it will be assumed that they traded at an equilibrium price of $25/rMWh.

At the close of the Day-4 session, the supplier would be sent a trade confirmation for 25 rMWh of regulating reserves to be supplied from HE01 through HE06 for September 1. The supplier has a firm obligation to perform at this service level. It would also receive similar notifications of any transactions for the other three reserve markets.

Now assume that the supplier re-enters the September 1 off-peak market on Day-1, still with a sold position of 25 rMWh from HE01 through HE06 at $25/rMWh. The supplier notes that the day-ahead energy market for September 1 is indicating a trade price of $25/MWh, and that the regulating reserve index market is being offered at -$4/rMWh, indicating a settled price of $21/rMWh ($25 - $4). The supplier puts a bid into the index market at -$4 for 25 rMWh, all-or-nothing, for HE01 to HE06. It observes at 10:00 that the day-ahead energy market closed at $25.50/MWh and at noon its -$4/rMWh bid is within market for index-priced regulating reserve. The supplier has now offset its obligations for regulating reserves for HE01 through HE06 on September 1. The net effect is that the supplier sold 25 rMWh at $25 on Day-4 and bought 25 rMWh at $4 below index on Day-1, where index is the energy closing price of $25.50. The supplier will receive a payment of 25.00 – (25.50 - 4.00) = $3.50/rMWh for 25 rMWh for the hours HE01 to HE06. It also has 25 rMWh of regulating reserve capacity that is no longer committed and is available to the energy market.

The supplier next decides, prior to the 14:00 closing of the standby market for regulating reserves, that it will offer the service as standby. For this market it places an offer in each of the six hours that includes a premium and an activation price as follows.

Table 7.6: Standby Regulating Reserves for September 1

Hour	Bid			Offer			Last	
	Volume	Activ'n Price	Premium	Premium	Activ'n Price	Volume	Price	Vol.
HE01	50	$30	$5	$5	$30	25	$5	25
HE02	50	$30	$5	$5	$30	25	$5	25
HE03	50	$30	$5	$5	$30	25	$5	25
HE04	50	$30	$5	$5	$30	25	$5	25
HE05	50	$30	$5	$5	$30	25	$5	25
HE06	50	$30	$5	$5	$30	25	$5	25
…								

The supplier noted that the standby market was being bid at $5/rMWh for a $30/rMWh activation price and was seeking a volume of 50 rMWh for each of the six hours. The supplier sold to this market, at the bid price, a volume of 25 rMWh in each hour. The supplier would be notified of a successful trade as soon as its offer is selected by a buyer; that is, the standby market uses bid/offer matching rather than equilibrium pricing. It is not possible to establish a meaningful clearing price when two-part offers (premiums and activation prices) are being used.

At 16:00 on Day-1 the supplier would be notified that it had no obligations for active regulating reserve for HE01 to HE06, but that it did have 25 rMWh of supply available in the standby merit order at an activation price of $30/rMWh. It would also be provided with an indication of where in the queue these volumes stood. At this juncture, the supplier is still free to offer the 25 rMWh to the hourly energy market and will be receiving a payment of $5/rMWh for standby and a $3.50/rMWh gain on trades for active reserves.

At settlement, the supplier will receive the $8.50/rMWh from the ancillary services market plus $30/rMWh for any of the reserves that may have been called on during HE01 to HE06 on September 1. The supplier would receive the hourly pool price if it were successful in selling to the energy market.

· Operations Walkthrough

i. Resource States

A resource that is capable of providing ancillary services can be in one of four states at any given time. These states are:

- *Unavailable:* A resource in this state is not available to supply ancillary services. The unavailability may have a physical origin (i.e., the resource is on a forced or maintenance outage), but it may also have a "market" origin. That is, the Transmission Administrator considers any resource that does not have an accepted market offer to be either unwilling or unable to supply ancillary services. Except under explicitly declared emergency circumstances, resources in the *unavailable* state will not be called upon to provide ancillary services.

- *Active:* An active resource is one that has the both the physical capability and the commercial willingness (as demonstrated through a valid, accepted offer in the ancillary services market) to carry out specified ancillary service obligations in response to instructions from the System Controller. For example, a generation unit that has been constrained down to provide spinning reserve, and a load that has been "armed" to provide supplemental reserve, are both in the *active* state. Similarly, a generation unit is in the active state if it is continuously adjusting its output in real time in response to automatic generation control (AGC) signals.

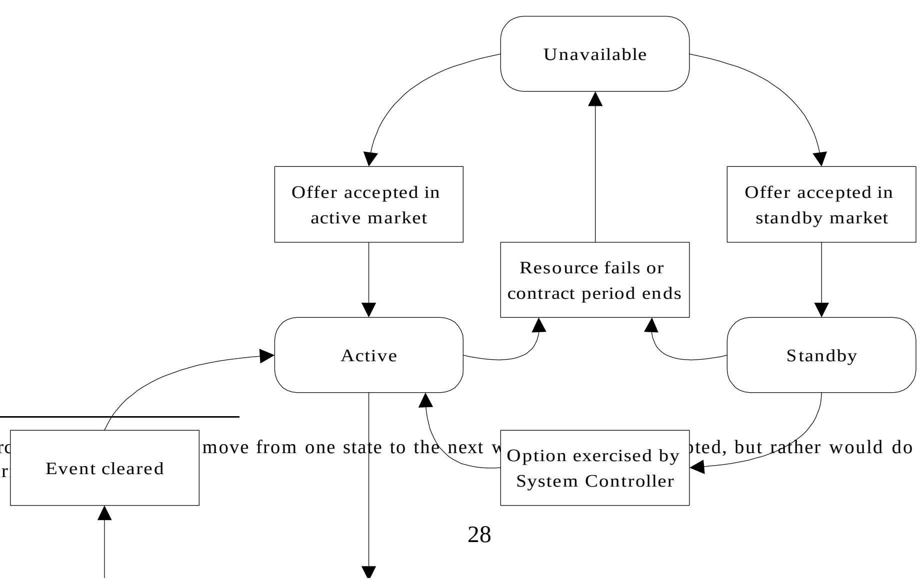
- *Standby:* A resource in the *standby* state is not providing ancillary services, but could be called upon to do so by the System Controller. There are no restrictions on a standby resource's participation in the energy market, but within a contractually specified time following notification by the System Controller the resource must move to the *active* state described above. In essence, a resource in the standby state has sold an option to the Transmission Administrator that can be exercised by the System Controller.

- *Deployed:* A resource in the *deployed* state has responded to a system event and, as a result, may no longer have the ability to respond to another event. For example, consider a 400 MW generation unit that is constrained down to 350 MW, so that it is providing 50 rMW of spinning reserve. If the reserve unit's output goes to 390 MW in response to an instruction from the System Controller, then the reserve obligation has been met but the unit is no longer capable of providing 50 MW in response to another event.

Figure 7.4 provides a graphic illustration of the main transitions between one state and another. From the *unavailable* state, a resource can move into the *active* or *standby* states by having an offer accepted in the appropriate market.[35] If the resource subsequently fails, or the contract (delivery) period ends, the resource moves back to *unavailable*. If a system event occurs that requires a response from a resource in the *active* state, that resource moves to the *deployed* state and remains there until such time as the event is cleared or the contractual obligations have been met. If a resource in the *active* state suffers a forced outage, or if adequate reserves were not procured in the active market, then the System Controller can exercise the option on a resource in the *standby* state, moving it to the *active* state.

The obligations on ancillary service resources in each state case be illustrated using an example in which a generation unit has a spinning reserve offer accepted in the standby market (see Figure 7.5). Prior to offer acceptance, the unit is unavailable for the provision of ancillary services and there are no restrictions on its output level.

Upon reaching the delivery hour for the standby reserve, the unit moves to the *standby* state. It's output may still be any value from zero to its maximum capability rating, as there are no restrictions on standby unit output imposed by the market contracts. The unit could be off line, it could be generating energy at maximum output, or it could be operating at any point in between. Clearly, however, it must be capable of actually delivering spinning reserves—that is, of moving to the *active* state—within the time limits set out in the standby contract. While in the standby state, the supplier receives its premium.



[35] The resourc ... move from one state to the next w ... pted, but rather would do so when the relevant delivery period ar...

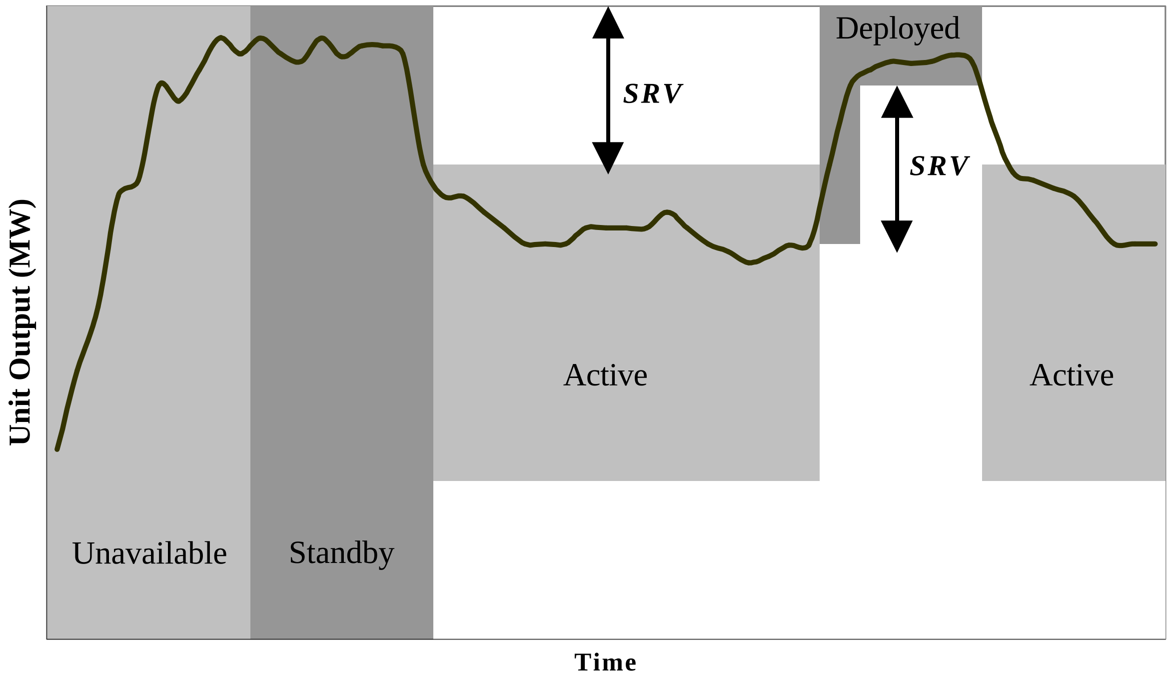


Figure 7.5. The transition of a spinning reserve resource through various states. The shaded regions show the permissible output values, while the solid line shows actual unit output in this example. SRV is the contracted spinning reserve volume.

During the delivery hour, if the System Controller calls on additional resources (for example, because of a forced outage on another resource or because of an under-forecast of active resource requirements), the call option is exercised and the resource is "activated," that is, it is moved into the *active* state. Restrictions on unit output do exist in this state: the unit must be on line and synchronized—and therefore must be running at least at minimum output—and its output must be at least SRV MW below its maximum, where SRV is the spinning reserve volume.

If a contingency occurs when the unit is active then it moves into the *deployed* state. Assuming the System Controller dispatches the full amount of reserve, the unit's output must rise by at least *SRV* MW within 7 minutes. Once the contingency has been cleared, generally by making additional energy market dispatches,[36] the generation unit would move back to the *active* state and its output must return to a value at least *SRV* MW below its maximum.

It should be note that other transitions from one state to another are possible. For example, if the delivery hour has ended and no valid offer exists for the next hour, a resource could move directly from *deployed* to *unavailable* once the event to which it responded is cleared.

ii. The Ancillary Services Portfolio

By the close of the Day–1 market, the Transmission Administrator will have assembled a quantity of active and standby reserves that it feels will meet system requirements for each hour in the 24-hour period beginning at midnight. To keep the following example simple, it is assumed that the Transmission Administrator's portfolio is for a single hour (HE 01) and provides for normal system operations and coverage for a single-contingency generation unit failure. Other assumptions, which are for illustrative purposes only, are as follows:

2. In acquiring contingency (spinning and supplemental) reserves, the Transmission Administrator forecasts that the volume-determining factor is the requirement to provide coverage for the trip of a single 400 MW unit. Thus,

[36] The rules around making additional energy market dispatches on units that have made commitments through the day-ahead energy market have not been defined. These rules may have an effect on the mechanics and timing of a reserve provider's transition from *deployed* back to *active*. In any case there will be an upper limit, probably one hour, on the length of time a unit will be expected to remain in the deployed state in response to a given event.

on a forecast basis, the WSCC "5% of hydro and 7% of thermal" rule does not affect the quantity of reserves to be provided.

3. A total of 250 rMW each of standby spinning and standby supplemental reserves are needed.
4. In addition to spinning and supplemental reserves, regulating reserve with 130 rMW of control range is required.
5. A quantity of load following equal to about one third of the morning load ramp of 600 MW/h, and requiring a ramp rate of 8 MW/min, is required.

The resulting ancillary service portfolio is as follows:

Table 7.7: Ancillary Services Portfolio

Reserve Type	Active	Standby
Regulating	130 rMW control range	50 rMW control range
Spinning	200 rMW	250 rMW
Supplemental	200 rMW	250 rMW
Load Following	200 rMW, 8 MW/min ramp	50 rMW, 2 MW/min ramp

In addition to gross volumes, other factors must be considered. For example, the Transmission Administrator must ensure that both active and standby reserves are distributed across the available resources to provide sufficient diversity to ensure that a generator failure adversely affects only an acceptable quantity of reserves. Having regard for some of the limitations imposed by its diversity requirement, the following table provides an example of what the Transmission Administrator's portfolio might look like.

Table 7.8: Ancillary Service Portfolio

	Load Following		Regulating Reserve		Spinning Reserve		Supplemental Reserve		Total
Facility	**Active**	**Standby**	**Active**	**Standby**	**Active**	**Standby**	**Active**	**Standby**	
Generator 1 Unit 1		25							**25**
Generator 1 Unit 2			35						**35**
Generator 1 Unit 3				35	70				**105**
Generator 1 Unit 4	35					70			**105**
Generator 2 Unit 1					30				**30**
Generator 2 Unit 2	30		30						**60**
Generator 2 Unit 3				30			25		**55**
Generator 2 Unit 4		25				30			**55**
Generator 3 Unit 1	40		30						**70**
Generator 3 Unit 3					40				**40**
Generator 3 Unit 4						40			**40**
Generator 4 Unit 1			15						**15**
Generator 4 Unit 3	20								**20**
Generator 5 Unit 1					30	30	50		**110**
Generator 5 Unit 2								100	**100**
Generator 5 Unit 4							100		**100**
Generator 5 Unit 6	75		20			50			**145**
Generator 5 Unit 7					30	30			**60**
Generator 5 Unit 8								50	**50**
Industrial 1							10	10	**20**
Industrial 2							15	25	**40**
Industrial 3								15	**15**
Industrial 4								50	**50**
Grand Total	**200**	**50**	**130**	**65**	**200**	**250**	**200**	**250**	**1345**

For each ancillary service, the market operator will provide the System Controller with a list of the associated resources by 16:00 each day. In addition, a standby reserve merit order will be provided for each service with resources ranked from lowest activation price to highest activation price. Additional information such as whether the supplier will accept a partial dispatch would also be provided.

Table 7.9 is representative of the kind of information the System Controller would receive for active reserves. The System Controller does not require pricing information since it is intended that all available active reserve be used.

For standby resources, the price at which the reserve may be activated is provided in addition to the information provided for active resources. Table 7.10 shows an example of the kind of information the System Controller would need to have regarding the Transmission Administrator's standby purchases.

i. Operational Examples

Between the closing of the days-ahead market and real time a number of events may take place that affect suppliers or the quantity of reserves required. In broad terms the four events are:

(a) None (no variation from forecast).
(b) The Transmission Administrator buys too much or too little active reserve when compared with the System Controller's real-time requirements.
(c) Suppliers become unavailable to deliver the contracted services.
(d) A contingency affects the system in real time.

These events may occur in isolation or in combination, and the market and the associated information systems must be robust enough to withstand the effects of such events. The following examples take some of the likely events in isolation and in combination to illustrate the implementation of the proposed market design.

Table 7.9: Active Reserves

State	Service	Supplier	Nominated Facility	Capability or Control Range	Ramp Rate	Activation Price
Active	Load Following	Marketer A	Generator 1 Unit 4	35	2	
Active	Load Following	Marketer B	Generator 2 Unit 2	30	2	
Active	Load Following	Marketer A	Generator 3 Unit 1	40	2	
Active	Load Following	Marketer A	Generator 4 Unit 3	20	2	
Active	Load Following	Generator 5	Generator 5 Unit 6	75	20	
Active	Regulating Reserve	Marketer A	Generator 1 Unit 2	35		
Active	Regulating Reserve	Marketer B	Generator 2 Unit 2	30		
Active	Regulating Reserve	Marketer A	Generator 3 Unit 1	30		
Active	Regulating Reserve	Marketer A	Generator 4 Unit 1	15		
Active	Regulating Reserve	Generator 5	Generator 5 Unit 6	20		
Active	Spinning Reserve	Marketer A	Generator 1 Unit 3	70		
Active	Spinning Reserve	Marketer B	Generator 2 Unit 1	30		
Active	Spinning Reserve	Marketer D	Generator 3 Unit 3	40		
Active	Spinning Reserve	Generator 5	Generator 5 Unit 1	30		
Active	Spinning Reserve	Marketer D	Generator 5 Unit 7	30		
Active	Supplemental Reserve	Marketer B	Generator 2 Unit 3	25		
Active	Supplemental Reserve	Generator 5	Generator 5 Unit 1	50		
Active	Supplemental Reserve	Generator 5	Generator 5 Unit 4	100		
Active	Supplemental Reserve	Industrial 1	Industrial 1	10		
Active	Supplemental Reserve	Marketer C	Industrial 2	15		

Table 7.10: Standby Reserves

State	Service	Supplier	Nominated Facility	Capability or Control Range	Ramp Rate	Activation Price
Standby	Load Following	Marketer A	Generator 1 Unit 1	25	2	$ 20.00
Standby	Load Following	Marketer B	Generator 2 Unit 4	25	2	$ 25.00
Standby	Regulating Reserve	Marketer A	Generator 1 Unit 3	35		$ 55.00
Standby	Regulating Reserve	Marketer B	Generator 2 Unit 3	30		$ 60.00
Standby	Spinning Reserve	Marketer A	Generator 1 Unit 4	70		$ 31.00
Standby	Spinning Reserve	Marketer B	Generator 2 Unit 4	30		$ 33.00
Standby	Spinning Reserve	Marketer C	Generator 3 Unit 4	40		$ 35.00
Standby	Spinning Reserve	Marketer A	Generator 5 Unit 1	30		$ 50.00
Standby	Spinning Reserve	Marketer D	Generator 5 Unit 7	30		$ 75.00
Standby	Spinning Reserve	Marketer D	Generator 5 Unit 6	50		$ 76.00
Standby	Supplemental Reserve	Industrial 1	Industrial 1	10		$ 8.00
Standby	Supplemental Reserve	Industrial 2	Industrial 2	25		$ 12.00
Standby	Supplemental Reserve	Generator 5	Generator 5 Unit 2	100		$ 13.00
Standby	Supplemental Reserve	Industrial 3	Industrial 3	15		$ 100.00
Standby	Supplemental Reserve	Marketer C	Industrial 4	50		$ 250.00
Standby	Supplemental Reserve	Generator 5	Generator 5 Unit 8	50		$ 300.00

Example 1: No Variation

In the first scenario, no contingency affects the ancillary service supply offered for the delivery hour between the closing of the day-ahead active market and real time, and the Transmission Administrator's purchases of regulating, spinning and supplemental reserves match the System Controller's real-time requirements. In this case, the System Controller dispatches all *active* regulating, spinning and supplemental reserve acquired by the Transmission Administrator. The System Controller dispatches regulating reserve and load following as required to balance system supply and demand.

Example 2: Spinning Reserve Purchases Exceed Real-time Requirements

In this example the Transmission Administrator has procured more active spinning reserve than the System Controller determines is required in real time. In this case the System Controller dispatches the surplus spinning reserve anyway. The Transmission Administrator is accountable to provide an accurate forecast of requirements to the market and to buy against that forecast. Real time energy market participants are relying on a good reserve volume signal from the Transmission Administrator that is best enforced by not permitting the Transmission Administrator to resell volumes in real time.

It should be noted that the magnitude of any ancillary service forecast error would be quite small, because it would only be a small fraction (~5 to 7%) of any load forecast error. Notwithstanding the small size of the potential error, the Transmission Administrator could set its forward purchase target a bit below 100% of its forecast requirement for active reserve, and rely on the standby queue to make up any shortfall, in order to minimize the frequency with which "excess" reserves are carried in real time. Setting the target so low that forecast reserves *never* exceed real-time requirements, however, would likely result in paying too much for standby resources. Alternative (or perhaps complementary) over-forecast risk mitigation options, which could perhaps be incorporated in a *future* version of the market, include over-the-counter deals and "decremental" offers, under which the Transmission Administrator could reduce the volume purchased from a supplier.

The Transmission Administrator may also avail itself of market opportunities after market close but prior to real time to prudently manage its costs of reserves acquisition.

Example 3: The Transmission Administrator Buys too Little Spinning Reserve

If the Transmission Administrator purchases active reserve based on a too-low forecast, the System Controller will activate sufficient reserve from the standby queue to make up the shortfall. In the event that insufficient reserve is available in the standby queue, the System Controller will issue a "Reserves Deficiency Order." Such an order will permit the System Controller to acquire ancillary services from the energy market under terms and conditions applicable to emergency situations. The issuance of a Reserves Deficiency Order will trigger a review of the circumstances leading up to that issuance to ensure that the number of times such emergency procedures are invoked is kept to a minimum.

Example 4: Resource Failure Prior to Real Time

In this example one active reserve provider, having sold some quantity of spinning reserve for HE 01, provides notice of failure prior to real time. The provider does not designate a replacement supply. In this case, in addition to dispatching the available active reserves, the System Controller will dispatch sufficient reserves from the spinning reserve portion of the standby queue to meet its real-time reserves requirements.

In the case of the example portfolio presented above, if Generator 2 Unit 1 (G2U1) became unavailable to provide reserve, then the System Controller would need to replace 30 rMWh of active spinning reserve. The lowest-price offer for standby reserve is Marketer A, who is offering 70 rMWh of spinning reserve from G1U4. The System Controller can fully replace the failed reserve by activating a portion of the reserves available from G1U4. The payment to Marketer A would be its activation price of $31 / rMWh for that portion of the offer that was activated (unless it was an all-or-nothing offer, in which case it would be cheaper to activate all or a portion of the next two units in the queue).

If the Transmission Administrator has acquired more active supply than required in real time, then the quantity of reserves the System Controller activates from the standby queue will be reduced accordingly. If insufficient spinning reserve exists in the spinning reserves standby queue, the System Controller may activate regulating reserve to meet system requirements. Similarly, if supplemental reserve is in short supply, then higher-quality spinning reserve may be substituted. This example highlights a general principle that, if the standby queue for a particular ancillary service is exhausted, the System Controller will look to higher-quality services before issuing a Reserves Deficiency Order.

If a supplier becomes aware sufficiently far in advance of the delivery hour that a resource will be unable to meet an ancillary service commitment, that supplier may designate a replacement resource and provide notification of that substitution to the System Controller.[37] The System Controller would dispatch that replacement supply with no impact to the Transmission Administrator or to the active or standby queues. A supplier may not designate supply that is already contracted to provide ancillary services to the Transmission Administrator unless sufficient *additional* capability is available and no reliability criteria (e.g., too much reserve coming from a single unit) are violated.

Example 5: Contingency on a Non-Reserve-Providing Generation unit

The loss of a 400 MW generation unit requires the deployment of essentially all spinning and supplemental reserve within 10 minutes (while retaining regulating reserve), and then restoring the reserves within one hour. The following charts show the contribution of various resources on the AIES to a successful recovery.

As shown in Figure 7.6, the contingency in this example occurs at minute 10 of the hour. The initial replacement of the lost supply comes from an energy inflow on the BC tie. Alberta has a responsibility, under NERC rules, to adjust its supply and demand such that the difference between actual and scheduled flows[38] is reduced to zero within 10 minutes. The means for reducing inflow on the BC tie line is to cause energy to be produced, or to have consumption reduced, by resources providing contingency reserves.

Active reserve is acquired using an equilibrium pricing mechanism in the days-ahead markets, and therefore in real time all active reserve is equal from a financial perspective. Price is not an issue during deployment since reserve providers are paid on the basis of prices agreed upon in advance.[39] From a real-time perspective, the cost of active reserves is a sunk cost. The consequences of deployment have been factored into prices at which reserves were offered to the market. Where less than full deployment of reserve is required, the System Controller will choose which reserves to deploy on the basis of fairness and operational capabilities. The present market design does not expect the System Controller to financially optimize deployment of the active reserve, only to restore the system to order. It is expected that the financial optimization will ultimately come from the market itself, as suppliers optimize their own energy and ancillary service portfolios.

Figure 7.7 shows the transformation of active spinning and supplemental reserves to energy as a result of the System Controller's dispatch instructions. That is, AIES generation increases after minute 10, resulting in a decrease in the level of active reserves. The active reserves include regulating reserve that must be maintained even when a contingency occurs, which is why the active reserves do not decline to zero. Load following reserves are in addition to the quantities shown here.

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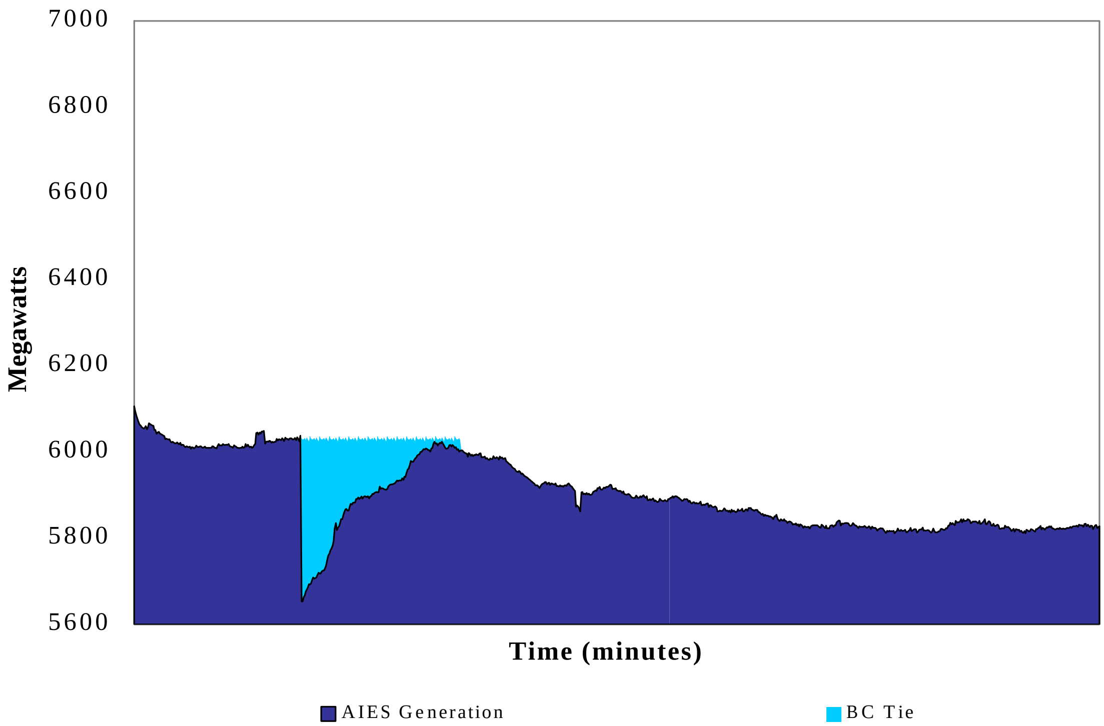
[37] The detailed mechanism by which this notification will be made will be established as the market's information systems are developed.

[38] That is, the Area Control Error (ACE) must be reduced to zero within 10 minutes.

[39] Note that when reserve is deployed, reserve suppliers receive pool price—which may include a profit component—for the energy produced.

This deployment of reserves fulfills the first of two commitments to the WSCC and system security. The second is to replace the active reserves within 60 minutes of a contingency. Given that the first 10 minutes after a contingency is consumed with the deployment of reserves, the remaining 50 minutes must provide sufficient time to restore reserves to target levels. This time limitation dictates that the source of the resources that will replace the deployed ones must be known in advance. To the extent possible under energy market rules the System Controller will restore reserves by re-dispatching the energy market and moving reserve providers from the *deployed* state back to the *active* state. In cases where this is not possible—for example, where a load providing supplemental reserve has a minimum down time—it is necessary to know in advance the resources that will replace the deployed ones. The standby queue provides those resources.

Figure 7.8 shows the transformation of resources from the standby state into the active state. The Transmission Administrator incurs activation charges when the System Controller causes standby reserves to be activated. This



process requires that the System Controller have a clear view of the pricing in the standby queue so that least-cost reserves are activated.

Figure 7.6: Initial response to a contingency.

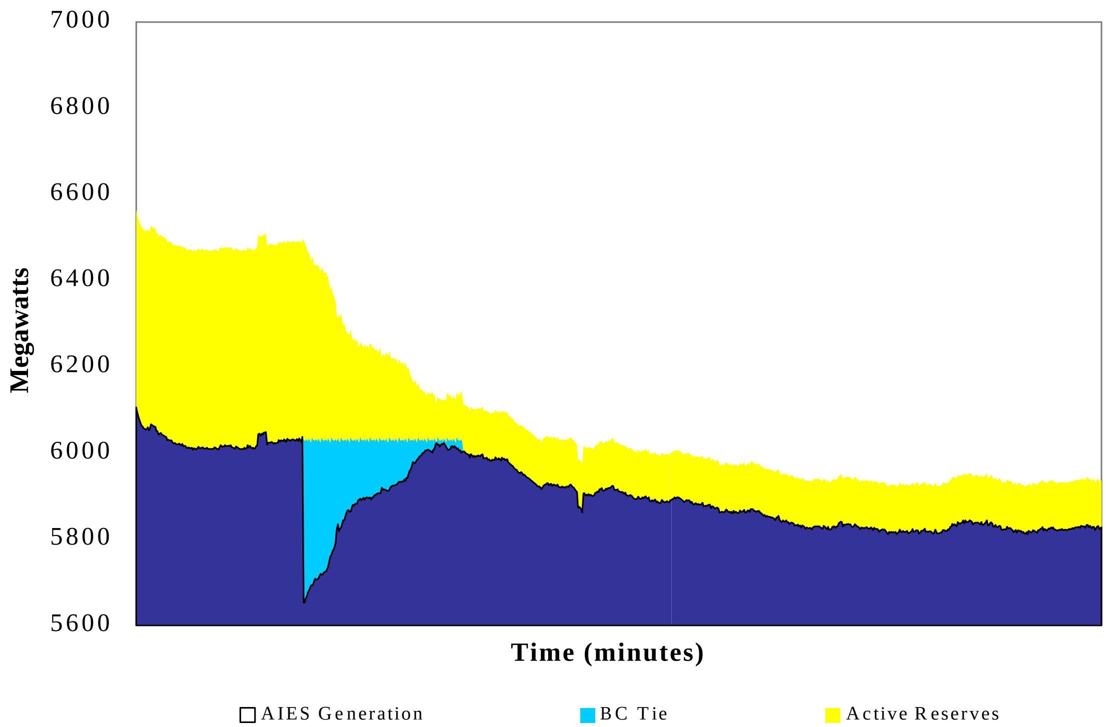


Figure 7.7: Transformation of active reserves to energy.

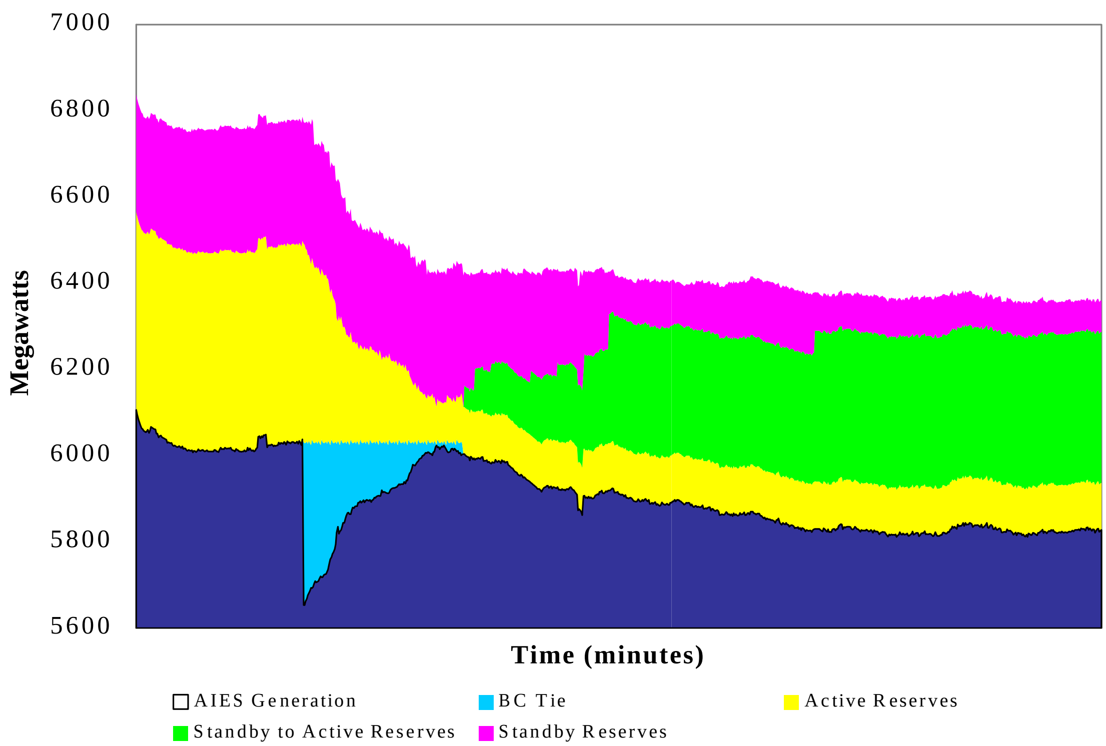


Figure 7.8: Transition of standby reserves to the *active* state.

ii. *Active and Standby Volumes*

The Transmission Administrator will determine the active and standby volumes of each ancillary service to be procured in the market. These volumes will be based on target reliability levels, NERC / WSCC criteria, conditions extant on the AIES, detailed analysis of historical operating data, and extensive consultation with the System Controller. The volumes must provide for the management of multiple contingencies.

Presently, the Transmission Administrator has an option to acquire reserve from essentially all regulated generation. That amount of reserve coverage would exceed an amount judged prudent in a market context. The design of the Transmission Administrator's ongoing portfolio requirements will evolve over time as experience is gained with the market.

iii. Summary

As highlighted by the above examples, the communication between the market operator and the System Controller is very structured, and it leads to a clear identification of assets under contract to provide ancillary services. Limited systems infrastructure will be required to enable this portion of the reserves market proposal.

The design proposal also avoids the construction of a complex least-cost dispatch algorithm for reserves, relying instead on market forces to provide the necessary signals to determine which assets will provide reserves in real time. The proposal anticipates that at some future date the days-ahead market may be extended to an hours-ahead market to facilitate a more direct means of managing replacement of real-time reserves. Given the small size of the Alberta market, limiting development to the days-ahead market is justified for now.

2. RESPONSES TO QUESTIONS FROM SECTIONS 3, 4 & 5

This section repeats each of the questions posed in Sections 3, 4, and 5, and recommends answers thereto based on the stakeholder consultation process and the market design presented in the previous section. The responses are based on the assumption that the ancillary services market is workably competitive.[40] When reviewing the answers in this section, it should be understood that the term "ancillary services" may mean *all* ancillary services or just those deemed amenable to market-based procurement—namely regulating reserve, load following, spinning reserve, and supplemental reserve. The intent should be clear from the context.

· The Role of the Transmission Administrator (Section 3)

- *Should the Transmission Administrator engage in fixed-price forward purchases of ancillary services?*

For those services deemed not amenable to market-based competitive procurement the answer is an unqualified "yes." For market-based services, the design being proposed by the Transmission Administrator provides for purchases up to five business days in advance of the delivery day. Such advance purchases provide some certainty to the Transmission Administrator and the System Controller regarding the availability of services, and avoid the potential problems associated with sellers knowing exactly when and in what quantity purchases will be made. The advance purchases should also reduce the volatility of ancillary service prices currently faced by the Transmission Administrator.

As a general principle, the Transmission Administrator will consider entering into forward arrangements for market-based ancillary services where it is prudent to do so, competition is enhanced, and all technical requirements can be met. While stakeholders generally supported the acquisition by the Transmission Administrator of a portfolio of ancillary service contracts, there was also a desire that forward purchases not be so extensive that they stifle the development of a competitive market. It is difficult at this stage to provide definitive rules for forward acquisition, but the Transmission Administrator is committed to purchasing the majority of market-based ancillary services through short-term, rather than long-term, instruments.

- *What fraction of forecasted volumes should be procured in advance?*
- *What is an appropriate mix of contract periods?*

As noted in the answer to the previous question, providing a commitment as to when and in what volume ancillary services will be acquired provides sellers with market data that will make competitive procurement more difficult for the Transmission Administrator. However, as an initial guideline, to be applicable for 2001, the Transmission Administrator suggests that monthly contracts for supplemental reserve from load, for up to one half of the forecast supplemental reserve requirement, *may* be entered into. All other market-based ancillary services will be purchased strictly through the market, that is, no further than five business days in advance of delivery.

- *How are differences between contracted and actual volumes accounted for, both in aggregate and for individual suppliers?*

Market-based ancillary service contracts will provide for tolerance bands around contracted volumes, within which the supplier will be deemed to have met the terms of the contract. The question of whether financial adjustments for deviations within the tolerance bands are required will be addressed during the development of the actual ancillary service contracts. The Transmission Administrator does not contemplate compensating for deliveries above the tolerance band, while deliveries below the tolerance levels will be dealt with according to the non-performance provisions in the contracts.

- *What implications will forward purchases have on the development of an ancillary services market?*

Significant forward purchases will reduce the liquidity in the ancillary services market and may affect efficient price discovery. At least until suppliers become familiar with the market and liquidity is established, forward purchases should be limited as described above.

- *Should the Transmission Administrator act as a market maker?*

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[40] "Workably competitive" is defined in Section 8.3.

By virtue of its commitment to purchase a significant fraction of its total ancillary service requirements in the competitive market, the Transmission Administrator is effectively a market maker. To recognize the sizeable role the Transmission Administrator plays in the acquisition of reserves, the active markets have been designed with equilibrium pricing rather than bid / offer pricing.

- *If contracted volumes exceed actual requirements as a result of forecast error, can the excess be turned back into the energy market, and if so, who receives the proceeds from the energy sales?*

Please refer to Section 7.4.1 for a discussion of the conditions under which “excess” ancillary services can be converted into energy. See also Appendix E.

- *What role should the Transmission Administrator play in the development and operation of an ancillary services “market?”*

EAL believes that it has a mandate from stakeholders to facilitate the development of a market, and proposes to do so by defining contract requirements, qualifying suppliers, and committing to purchase a significant fraction of its ancillary services through markets. EAL also believes that market operation should be left to third party market operators. The Transmission Administrator will not “select” market operators, but rather will work with any operators interested in pursuing the requisite developments. However, given a strong desire among stakeholders to have a market in place for 2001 January 1, EAL will ensure that contingency plans are in place should certain development milestones not be met.

· Procurement Options (Section 4)

i. Market-Based Procurement

- *For what ancillary services, if any, is the market-based approach the best one? Should priority be placed on market-based procurement for certain services?*

Discussions with Alberta stakeholders have led EAL to conclude that regulating reserve, load following, spinning reserve, and supplemental reserve are good candidates for market-based procurement. The best form of procurement for interruptible load remedial action schemes (ILRAS) has not been discussed fully. There was general agreement that black start and voltage control were not good candidates for market-based procurement (see Section 8.2.2).

- *What should be done to ensure that there are enough participants and that the market is sufficiently liquid? (e.g., Should market participation be mandatory, at least initially?)*

EAL believes that a fair, open, competitive market through which the Transmission Administrator is purchasing most of its ancillary service requirements has an excellent chance of drawing an adequate number of suppliers. By purchasing services frequently (i.e., no large, long-term contracts), minimizing entry barriers for new suppliers, and doing the other things discussed in Section 2 to encourage participation, EAL is confident of a successful market.

- *How important is it to have forward contracts and/or option contracts?*

Contracts beyond the five-day-ahead market are not recommended at this time. Longer-dated forward instruments may be developed by the market operator in response to participant demand, or they may be developed by the market participants themselves. Standby contracts are basically physical call options. As is the case for forward instruments, market operators will develop other types of options if the demand for them materializes.

- *Is secondary trading (that is, trading that does not involve the Transmission Administrator) a critical factor in the market?*

EAL’s recommendation is to allow, and in fact encourage, secondary trading to occur. There will undoubtedly be occasions when ancillary service suppliers find themselves with obligations they cannot meet as a result of forced outages. Another situation arises from the hydro PPAs, under which the owner has a financial obligation tied to the provision of reserves that it may be unable to meet physically in all hours. A market that allows providers to manage their risks by buying to cover short positions should increase the number of participants and reduce the size of risk premiums relative to what would exist if such trading were not allowed.

➢ *Is real-time (or near-real-time) trading necessary?*

While EAL proposes to purchase the bulk of its ancillary services prior to the day of delivery, there is a significant need to be able to adapt to real-time developments. For example, if a spinning reserve provider goes off line, a replacement for the lost reserve must be found within an hour. Real-time reserve deficiencies will be made up by activating reserves from the standby market (as discussed in Section 7) and perhaps through an over-the-counter market. It is important for the Transmission Administrator to make most of its active reserve commitments in advance of real time to avoid being cornered for high prices and to provide certainty to suppliers that reserve volumes will be purchased in an open and competitive environment.

➢ *What other risk mitigation options exist, and how critical are they to a successful market?*

With respect to system (reliability) risk, the System Controller has emergency powers that can be used to direct the operation of the AIES. With respect to potential ancillary service suppliers, the proposed market provides excellent risk management capabilities. If other options are required by suppliers, they will evolve as over-the-counter offerings or as instruments facilitated by the market operator(s).

➢ *What is the appropriate timing for the implementation of market-based acquisition of ancillary services, and what should the transition arrangements look like? Should there be a pilot (test) market first?*

The target implementation date for the market is 2001 January 1, the date on which the PPAs are slated to take effect. Selecting an implementation date beyond the effective date of the PPAs would necessitate the negotiation of short-life ancillary service contracts with PPA buyers. Pilot implementation will occur in advance of 2001 January 1, though detailed project plans won't be made until the basic market design has been set.

ii. Non-Market Competitive Procurement

➢ *For which ancillary services, if any, is this the most appropriate procurement model?*

Non-market competitive procurement is likely for reactive power/voltage control. Stakeholders noted that certain "reactively enriched" areas of the province might allow for some market-based procurement. However, given that there are many areas not so endowed, and that reactive power requirements are highly location-specific, the overall benefits of such an approach are likely to be minimal for the foreseeable future.

➢ *Would competitive, non-market approaches meet the requirement for reserves pricing for the hydro PPAs?*

EAL does not recommend that reserves be procured on a non-market competitive basis.

1.1.1

i. Non-Competitive Procurement

➢ *For which ancillary services, if any, is this the most appropriate procurement model?*

In its recent decision on Appendix E to EAL's 2001 transmission tariff application, the Alberta Energy and Utilities Board stated, "The Board is not persuaded that any services should be procured through non-competitive methods, outside of emergency situations."[41]

· Market Design and Operations Issues (Section 5)

i. General Questions

➢ *Who should initially develop the market, and what development model should be used?*

The Transmission Administrator should facilitate market development by third-party market operators, since they will be arms-length from all market participants and will have the expertise to operate a fair and efficient market for both buyers and sellers, the former including the Transmission Administrator.

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[41] Decision 2000-46, *ESBI Alberta Ltd., 2001 General Tariff Application, Phase I & II, Part A: System Support Services - Thermal Power Purchase Arrangements (Appendix E),* page 15.

- *How should the development be funded and how should the costs be recovered?*

EAL is hopeful that potential market operators will fund a substantial portion of the necessary development effort themselves. The costs that EAL prudently incurs for market development will be recovered through the appropriate component of the transmission tariff, subject to approval of the AEUB.

- *Who should operate the market on an ongoing basis?*

The third-party market operator(s) should manage the day-to-day operations.

- *Will market participants be allowed to provide their own ancillary services?*

This question should be dealt with as part of a future transmission application. Nothing in the proposed market design precludes the possibility of self-provision.

- *Will/should the Transmission Administrator be the sole buyer?*

As noted in the market design proposal in Section 7, the Transmission Administrator is not the sole buyer, although it is the sole end-use consumer of ancillary services.

- *How can ex-Alberta entities be encouraged to participate in the market?*

The proposed market presents ample opportunity for suppliers to participate, regardless of their location. Only certain technical and WSCC policy barriers will remain for delivery of some services.

- *Will the ancillary services market be "workably competitive?"*

A "workably competitive" market is one in which no single market participant can manipulate prices. EAL believes that there is a high probability that the market will be workably competitive, as would be evidenced over time by increases in the number of sellers, market offers, and trades. The answer will ultimately depend, of course, on the outcome of the PPA auction and the willingness of new suppliers to enter the market.

By creating an efficient market with transparent prices, and by providing a mechanism to manage the price and delivery risks associated with ancillary service supply contracts, EAL believes that enough supply can be encouraged to make competition a reality. Suppliers have the energy market as their alternative, so they are not coerced into selling at low prices. Conversely the Transmission Administrator, with multiple times to acquire its requirement, will not be cornered by suppliers knowing minimum volumes have to be purchased at a particular time; suppliers will be encouraged to offer competitive prices into each of these discrete markets.

ii. Interaction with the Energy Market

- *Regardless of the acquisition method(s), should the prices for ancillary services be tied formally to prices in the energy market?*

EAL is proposing to allow both fixed-price offers and indexed-price offers. The most likely index will be the closing price for the day-ahead energy market, as it will reflect market expectations for energy for the same time period as the reserve requirement. Given the Transmission Administrator's desire for price certainty and some suppliers' desires to delay price commitments as long as possible, there is a possibility that certain market participants might attempt to arbitrage the two pricing mechanisms. It is possible that one pricing option—fixed or indexed—will dominate over time, making the other obsolete.

- *What will the energy market look like, and to what extent does its final form affect ancillary service procurement?*

The proposed market design allows ancillary service suppliers to trade before and during the day-ahead energy trading session, and then allows them to finalize their ancillary service commitments through a final trading session closing after the day-ahead energy market closes. This should allow suppliers adequate time to manage their commitments to each market regardless of the final design of the energy market.

- *How closely can the energy and ancillary services dispatch processes be linked? Should an attempt be made by the System Controller to simultaneously optimize the energy and ancillary service dispatches, or should they be kept separate?*

EAL has stated from the outset that it expects that the System Controller will dispatch ancillary services in real time. From that perspective the dispatch processes are inextricably linked.

With respect to optimization, there are certain policies that can be put in place to ensure an efficient dispatch given market conditions. For example, if the Transmission Administrator can fulfill its reserve obligations by purchasing extra spinning reserve to supplant more-expensive, lower-quality supplemental reserve, then that should unquestionably be done.[42] However, joint optimization as used in some jurisdictions—selecting energy and reserve resources to minimize total system costs—is not recommended for Alberta because it reduces market transparency and because it creates incentives for bidders to distort their bids, undermining efficiency.[43] Also, some "black box" optimization processes automatically assume that suppliers are indifferent to supplying energy or ancillary services (given revenue equality); these processes modify the energy and ancillary service dispatches accordingly. The Transmission Administrator believes that market participants must have the ability to decide for themselves, through their offers into the energy and ancillary services markets, how they wish to be dispatched.

Another feature of algorithmic optimization is that it generally attempts to minimize costs across multiple time periods, often the 24 hours in a day. This daily, inter-temporal optimization may shift costs among hours, thereby reducing participants' incentives to adapt their trading or operations to on-peak or off-peak hours. In addition, inter-temporal optimization requires central dispatch decisions to ensure that resources are on line when required by the optimal schedule, and is therefore not compatible with generator self-commitment.

- *Can an* ex ante *reserves market coexist with an* ex post *energy market? What is required to make it work, and should it even be attempted?*

The proposed ancillary service price-setting mechanisms are independent of the real-time (*ex post*) energy price, though suppliers will have the option of tying their active ancillary service offer prices to the day-ahead energy price. EAL believes this arrangement will work well.

- *What is the impact on ancillary services pricing and dispatch of price/volume restatements in the energy market?*

EAL supports the use of contracts that are binding on both buyers and sellers. To the extent that energy market contracts are non-binding, upward pressure could be put on spot energy prices by withdrawal of offers. Because energy and some ancillary services are substitute products, an increase in energy prices will increase ancillary service prices and/or provide an incentive for capacity to be shifted from ancillary services to energy. The use of firm obligation contracts for active reserves and option contracts for standby reserves will provide adequate levels of safety despite restatements in the energy market. It is likely that, in the future, significant volumes of energy will be traded in a binding, day-ahead market, thereby minimizing the volume of energy market restatements.

- *How closely should ancillary service procurement methods be tied, in a systems sense, to the operation of the Power Pool? That is, is it necessary that potential suppliers be able to make ancillary services and energy offers through the same system?*

EAL considers the link to be desirable but not essential. For example, in California there are a number of different market operators and scheduling coordinators that interface with the Independent System Operator. At a minimum it will be necessary to provide real-time price information about the energy market within the reserves trading system.

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[42] In some jurisdictions this is called the "rational buyer" model.

[43] Cramton, Peter, and Robert Wilson, *A Review of ISO New England's Proposed Market Rules,* 1998 September 9, available at the University of Maryland web site at www.cramton.umd.edu.

- *Is it necessary and/or advisable to guarantee energy market opportunity costs to ancillary service suppliers by formally linking the prices?*

EAL believes its market proposal provides ample opportunity for suppliers to manage their portfolios effectively, and that an absolute guarantee of opportunity cost is neither required nor desirable. For one thing, the opportunity cost of every supplier is not the same, and not every participant will always be indifferent to providing energy or ancillary services. However, those suppliers who wish to have an opportunity cost link have the option, under the ancillary services market proposal, of pricing as a differential to a day-ahead energy price.

- *Will arbitrage occur between the energy and ancillary services markets, and if so, will that arbitrage be beneficial or detrimental to the markets?*

Arbitrage is the mechanism by which market participants, through their actions, ensure that prices are in line such that excessive profits cannot be made for a given level of risk. Properly designed energy and ancillary services markets will allow that arbitrage to take place. Arbitrage will be beneficial because it is the mechanism that ensures efficient pricing between the markets.

Further discussion of the relationship between the energy and ancillary services markets appears in Appendix E, which contains EAL's responses to comments on this subject made by the Power Pool of Alberta.

iii. Ancillary Services Pricing

- *What is the longest price interval (weekly, daily, daily on/off peak, etc.) that is compatible with the hydro PPAs?*

EAL is proposing an hourly market. As such, compatibility with the hydro PPAs is assured. Longer price intervals could be arranged for bilateral contracts (forward purchases) between suppliers, or between suppliers and the Transmission Administrator.

- *Would it be possible to derive shorter-interval prices from longer-interval ones? For example, could one use weekly ancillary service offers plus some other inputs to derive an hourly ancillary services price?*

Given that an hourly market is proposed, this will not be necessary.

- *Should reserve prices include both availability payments (i.e., payments for being "on call") and utilization payments (payments for actually being dispatched)? If so, how should the prices in the hydro PPAs be established?*

EAL suggests that an appropriate price benchmark for the hydro PPAs could be the one-day-ahead market price (though other options, such as the five-day average price for the delivery hour, could also be considered). The standby market will include an availability payment, but the suppliers therein are selling call options rather than ancillary services per se. The immediate-day-ahead market will be capable of being arbitraged against the energy market through index pricing and suppliers' own offer behaviour, and against the previous four trading days as sellers can become buyers if opportunities present themselves. The ability of the Transmission Administrator to meet its requirements across five buying sessions will make it very difficult to manipulate prices.

- *Is the auction process wherein all suppliers offering less than the market-clearing price receive that price advisable? How would such a mechanism work if suppliers could offer different combinations of availability payments and utilization payments?*

A clearing price will be established each trading day using the equilibrium-pricing model for the active market. Thus, all active ancillary services purchased within a trading day will receive the same price. Suppliers in the standby queue will receive their option premiums plus, if they are dispatched, their activation price. The activation price is a fixed offer for the service and will relate to the supplier's opportunity cost. There will not be a "clearing price" for standby as the price the Transmission Administrator is willing to pay will be a combination of the premium and the activation price. Since the expected-use probability will vary through time and over different volumes, a standby clearing price is not meaningful.

- *Is the equilibrium model, the bid/offer matching model, or some other model the most appropriate one for the ancillary services market?*

EAL is recommending the equilibrium model for the active ancillary services market. This pricing mechanism will be used to determine the trade price for each of five different trading sessions for each delivery hour. By using an equilibrium model in conjunction with five separate pricing sessions, it is believed that competitive pricing can be achieved without requiring 7×24 staffing in a relatively low-volume market.

The benefit of equilibrium pricing is that there is no time premium for when bids and offers are put into the market, and all trades are at the same price. The major drawback to equilibrium pricing is that it is relatively easy to manipulate prices, particularly if the buyer has to acquire known minimum levels of service. This is alleviated by employing five discrete equilibrium pricing sessions with no indication of when or what volumes the Transmission Administrator will buy.

➢ *Should prices be set* ex post *or* ex ante*?*

All prices will be ex-ante because the last trading session will close at least ten hours prior to delivery. For the active service markets the prices will be fixed at the closing price for each of the five trading sessions, or will be at a market-clearing differential to the day-ahead energy price. The latter should be available prior to the close of the final trading session for the ancillary services delivery day. Standby services will all be at fixed premiums with known activation prices.

➢ *Should there be a cap on ancillary service prices, much like there is on energy prices? If so, what is an appropriate value?*

A price cap will be used as long as there is an energy price cap. The fact that regulating reserves must be held even if firm load is curtailed, while spinning reserve and supplemental reserve can be given up prior to firm load curtailment, suggests a price cap above $1000 for regulating reserve and below $1000 for spinning and supplemental reserves.

➢ *If ancillary services are priced against an index, what is the most appropriate index?*

For all forward purchases, the most likely index is the day-ahead energy price.

1. Concluding Remarks

The ancillary service market design proposed in this document provides the best option for ensuring the reliability of the Alberta Interconnected Electric System in an economically efficient manner. The proposal addresses all of the major issues raised by the ongoing restructuring of the electricity industry in the province, including the auction of the Power Purchase Arrangements. Assigning the operation of that market to an independent market operator will ensure a reliable and effective trading environment and will help ensure the independence of the Transmission Administrator as a buyer of ancillary services.

ESBI Alberta Ltd. appreciates the contributions that industry stakeholders and the Power Pool of Alberta have made to the market development effort to date. We look forward to working with stakeholders and the System Controller to refine and improve the concepts discussed herein, and to develop cost-effective procurement methods that will ensure system reliability in a manner that is consistent with the overall philosophy behind the restructuring of Alberta's electricity industry.

Appendix A: Stakeholder Comments, 1999 December 13 & 14

The following comments were received in the consultation sessions held Monday, December 13 in Edmonton and Tuesday, December 14 in Calgary. Comments have been combined and/or paraphrased to provide the context in which they were made, and have been numbered for ease of reference. The comments received are not necessarily internally consistent, and their appearance here does not imply that the Transmission Administrator and/or all session participants were in agreement.

Monday, 1999 December 13 (Edmonton)

1. For certain services, negotiations with specific suppliers may be most appropriate. The benefit of this approach is that it may allow more flexibility in meeting the Transmission Administrator's requirements than a RfP approach. It was noted that negotiation may work for infrequently procured services like black start, but it would have huge G&A and other implications if done for other services (like spinning reserve).

2. Reactive power should be procured through non-market approaches, though competitively where possible. It was noted that "reactively enriched" areas of the province might allow for some market-based procurement. It was also suggested that the Transmission Administrator might want to incent the installation of larger exciters on new generators.

3. For most loads, the provision of ancillary services is not their core business. The process must allow terms that aren't so short that they make participation by loads onerous. Also, it may be appropriate to tie contract terms, such as availability, to conditions in other markets (e.g., pulp markets).

4. It was suggested, with respect to the procurement of ancillary services from loads, that something very simple be established in the beginning (i.e., start small). This would allow time to build trust in the procurement process in both the Transmission Administrator and suppliers.

5. The concept of monthly RfPs for spinning reserve, and perhaps for other forms of reserve, met with some acceptance. It was suggested that the Transmission Administrator should not buy a significant number of fixed-price forward contracts because that would make the genesis of a market much less likely.

6. Separate markets, or at least separate pricing, will be needed for constrained-down and constrained-on spinning reserve.

7. Spinning reserve is ripe for market-based procurement, but it is too early for an exchange because there are not enough suppliers. There is potential for an exchange over the long term if retailers have to provide their own reserves.

8. The Transmission Administrator is the sole buyer of physical ancillary services in real time, but is not necessarily the sole buyer in the forward market. Load should have the option to buy.

9. Price transparency is important.

10. Simultaneous optimization of the energy and ancillary services dispatches is a good idea but it will not work in the early stages. Let the market(s) evolve.

11. To minimize entry barriers, maybe suppliers should not be at risk for replacement costs in case of an outage. This may have implications for the timing of availability declarations and for the notice periods that can be provided to the make-up suppliers.

12. A flexible short-term market is better for everyone. The Transmission Administrator should minimize the amount of fixed-price forward purchases.

Tuesday, 1999 December 14 (Calgary)

13. It is important to have a fair and level playing field for all participants, including both loads and generators. Competition should be used to the maximum extent possible.

14. Black start procurement was discussed. Some suggested that a market might be possible. However, given TransAlta's provision at zero incremental cost[44] and its long-term, capital-intensive nature, it is unlikely that system-wide black start is a candidate for competitive procurement. Reliability (rather than cost) considerations may lead to a requirement for other suppliers, so potential black start providers are urged to discuss the matter with ESBI Alberta Ltd.'s technical staff. Long-term contracts are most appropriate here.

15. Market-based solutions are not warranted for reactive power. The *status quo* is acceptable, that being direct negotiation or RfPs as appropriate. For now, the focus should be on operating reserves.

16. There should be an hourly market for spinning reserves, similar in some respects to the present hourly market for energy. Monthly procurement is too infrequent. The costs of not having such a market, which would arise from the need to buy higher volumes, will far outweigh the cost of building the infrastructure to accommodate an hourly market. Same-time decisions on energy and spinning reserve dispatch, as well as (possibly) using the same dispatch infrastructure, will result in more efficient decisions.

17. It may be possible, and would be desirable, to create a spinning reserves market prior to the effective date of the PPAs.

18. The real-time market should be implemented first. Forwards, futures, and/or options can develop later if the market wants them. The Transmission Administrator does not need to play a role here—suppliers and marketers will make their own arrangements, through an OTC market, as needed.

19. The Transmission Administrator should not contract for physical spinning reserves on a forward basis, though one-month-forward financial contracts (price hedges) might be useful.

20. Fostering competition for ancillary services will not necessarily lead to the lowest possible cost in the short run, but should result in lower costs in the long run.

21. The Transmission Administrator should have a portfolio of contracts for ancillary services.

22. The decisions on which forward contracts to sign would be made by the Transmission Administrator based on its forecasts. The Transmission Administrator should not be "at risk" on this.

23. If there is adequate competition in the energy market in the post-PPA period, there should also be adequate competition for spinning reserves. Some stakeholders do not believe there will be adequate competition in the energy market.

24. Several pricing options for spinning reserve were discussed. It was suggested that the flexibility to chose between a fixed price, a multiple of pool price, or a fixed increment or decrement to pool price would be desirable. A Dutch auction process, in which all "in merit" suppliers receive a market-clearing price, is appropriate.

25. Linking the spinning reserve price to the energy market may help prevent gaming.

26. A monthly market for non-spinning reserve should be adequate, but dispatch must be hourly. Also, there must be some mechanism to provide notification of unavailability over a much shorter interval (e.g., a day ahead). The Transmission Administrator must be able to adapt to this unavailability.

27. The market for non-spinning reserve should not necessarily be linked to that for spinning reserve. On the other hand, many participants can offer both forms.

28. Stakeholders would like to see the Transmission Administrator's transition plan, particularly for 2001. The plan might start with non-market procurement and move to market-based procurement once certain criteria are met.

29. Penalties for non-performance, based on known compliance standards, are important. The lack of same led to severe problems in California.

30. There could be a role for the Transmission Administrator or an aggregator/marketer to organize loads so that, as a group, they can respond to contingencies.

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[44] Funds received by TransAlta for black start service are paid into the balancing pool.

31. If supply obligations are transferred to another party through a secondary trade, it is critical that the System Controller be made aware of the revised merit order.

APPENDIX B: DISCUSSIONS AT THE 2000 JANUARY 20 SESSION

The following items were discussed at the stakeholder consultation session held on 2000 January 20. Questions, comments, and responses have been combined and / or paraphrased, without (intentionally) changing the intent, to simplify this summary. The comments received were not necessarily internally consistent, and their appearance here does not imply that the Transmission Administrator and / or all session participants were in agreement. Also, a couple of points that were not discussed in the stakeholder session have been added to the responses for clarification; these points have been clearly identified.

At the end of the session it was concluded that a technical group consisting of representatives from the Transmission Administrator, the Power Pool, and industry should be formed to further develop potential solutions to some of the technical issues. Therefore, some of the items listed below will simply be referred to that group.

1. *Question:* Does a request for proposal (RfP) constitute market-based procurement?
   Response: In the context that the term is used in this document the answer is no. It is true that buyers issuing RfPs are going to a "market" to obtain prices. However, RfPs tend to be issued on an as-required, aperiodic basis in a process described in Section 4.2 as "non-market competitive." The term "market" was taken to imply that price discovery would take place on a regular (periodic) basis, such as daily or weekly. Thus, a process involving the daily submission of prices by potential suppliers would be considered a market for the purposes of this discussion.

2. *Comment:* The Transmission Administrator should take financial risk on ancillary services.
   Response: As indicated at the session and in this document's Revision History, ESBI Alberta Ltd. will prepare a discussion paper to address this issue specifically. This comment is in contrast to Comment 22 in Appendix A.

3. *Comment:* The Transmission Administrator's mandate should be to minimize the overall delivered cost of energy to end consumers.
   Response: This issue here is whether the Transmission Administrator's mandate is to minimize costs given a required level of transmission reliability (as indicated in Section 2.1) or to minimize the overall delivered cost of energy to end consumers. The difficulty with the former approach is that it may lead to the conclusion that it is acceptable to minimize ancillary services costs by causing a more-than-offsetting rise in the all-in cost of energy. The difficulty with the latter approach is that it assigns responsibilities to the Transmission Administrator for costs that are well beyond its reasonable control and obviously beyond its mandate. It was suggested that words that reflect a balance between the two extremes be added.

4. *Comment:* A spot market should be created first, and it should be non-binding.
   Response (revised 2000 July 26): As a buyer of a service that has mandatory minimum requirements, the Transmission Administrator could not make all of its purchases in real time without being exposed to higher costs that could be extracted by suppliers. A seller who is aware that a buyer is in a must-buy situation is able to drive up prices to capture windfall gains. This can occur in real-time electricity markets wherein the strategic withdrawal of one of a supplier's generating units can raise prices such that the revenue gain in respect of the supplier's other units more than offsets the loss of revenue associated with the withdrawn capacity.

   Commodity exchanges generally have rules that protect against sellers and buyers being able to manipulate prices through control of the commodity at the time of delivery. The following generally accepted exchange governance definitions for squeezes and corners illustrate this concern.

   Short squeeze: A situation in which the price of a stock or commodity rises as investors who sold short rush to buy it to cover their short positions and cut their losses. As the price of the stock increases, more short sellers feel compelled to cover their positions.

   Cornering the market: The illegal practice of attempting to purchase a sufficient amount of a commodity or security to manipulate its price.

   The problem for the Transmission Administrator is that it would be in the equivalent of a short squeeze for all purchases if it waits until real time to acquire its ancillary services. The sellers, knowing that the TA must acquire, will drive up prices to capture windfall gains. This practice of cornering the market, illegal in formal commodity exchanges, is executed by seller(s) having buyer(s) at a disadvantage in that the latter must buy to cover their short positions when the sellers control all of the physical volume.

   There are two possible and not mutually exclusive solutions to the short squeeze for the Transmission Administrator. The first, as proposed in the market design recommended in Section 7, is to meet ancillary service requirements with purchases over several days, so that sellers are not constantly aware of the volume and timing of the Transmission Administrator's purchases. The second option is to create elasticity in the demand for ancillary services, that is, to reduce the volume of services procured as prices rise. This option is perhaps worth exploring in the future, but is problematic in today's electricity market structure and, in any case, will require significant consultation with customers, the AEUB and standard-setting agencies like NERC and the WSCC.

Original Response: (The market design has evolved since this response was written.) It was, in fact, the Transmission Administrator's intent to create something very close to a spot market. The main purpose of the time lag between offer submission (1000h on the day prior to delivery) and the time of delivery was to allow for the development of the ancillary services merit order. As noted in Section 6.4, as the market matures, and as the systems needed to process information rapidly enough to adjust the merit order in real time can be constructed, the merit order could become more dynamic and closer to a "spot" merit order.

On the question of whether the spot market should be binding or not, both views have been expressed. The non-binding view was put forward by some at this session, while the view that there should be consequences for failure to deliver on an offer was expressed in December (see Appendix A, Comment 29). The technical group will discuss this issue further.

Another important point is that reserves and energy are different products. While insufficient energy may mean that some consumers have to curtail loads, insufficient reserves could lead to a complete system collapse. The prices of the products will be linked because generators have the choice of providing energy or reserves.

5. *Comment:* If ancillary service providers face consequences for non-performance, perhaps there should be consequences for transmission system unavailability as well.
Response: This issue is beyond the scope of the ancillary services project.

6. *Question:* Will there be adequate competition in an ancillary services market?
Response: ESBI Alberta Ltd. believes there is a good chance of success, but part of the reason for the stakeholder discussions, and for a project plan that includes a pilot implementation, is to better assess that chance. Also, contingency plans will be created to ensure the on-going delivery of services regardless of the level of competition or the timing of the implementation of market-based procurement processes.

7. *Comment:* The proposed payment mechanisms are overly complex, and the minimum price should be removed. All that's needed is a reserve price and an energy price.
Response (revised 2000 July 26): The market design has evolved significantly since this comment was made.
Original Response: ESBI Alberta Ltd. put this model forward one that reflects the comments made at the December consultation sessions. It should also be noted that the payment mechanisms are very similar to what exists today, and that most of the additional complexity arises from the desire to incorporate loads into the supplemental reserves market—again in response to comments made in December.

8. *Question:* Why does the Transmission Administrator's propose to use probabilistic methods to establish the ancillary services merit order?
Response: ESBI Alberta Ltd. believes this is an appropriate approach given some fundamental differences between energy and ancillary services, and between generators and loads as providers. The following example, which was not discussed during the session, may help clarify the issue.

Consider two providers of ancillary services, A and B. Supplier A offers reserves at $10/rMWh[45] plus $1000/rMW per contingency. Supplier B offers the same quantity of reserves at $12.50/rMWh plus $200/rMW per contingency. For the hour in question the unit costs paid by the Transmission Administrator would be as follows:

Option	No Contingency	One Contingency
A	$10	$1010
B	$12.50	$212.50

As shown in the table, if there is no contingency then the least expensive option is A, while if there is a contingency the least expensive option is B. The question is, how does the Transmission Administrator choose which option to accept?

The answer lies in a probability calculation. The *expected value* of a random variable, like a support service cost, is a probability-weighted average, and is the cost with no contingency times the probability of no contingency, plus the cost with a contingency times the probability of a contingency. (For the purposes of this simple example it is assumed that the probability of more than one contingency is zero.) Therefore, if the

[45] The unit "$/rMWh" means "dollars per 'reserves' megawatt per hour." Note that these offers are typical of the way loads have expressed an interest in offering their services, though the numbers are for example purposes and are not necessarily indicative of actual pricing

probability of a contingency is p, then the probability of no contingency is $(1-p)$, and the expected values of options A and B are

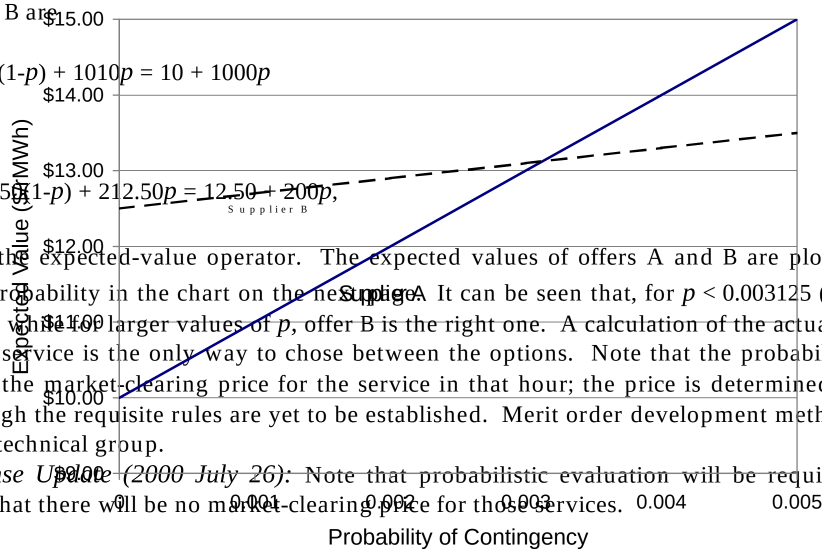
$$E[A] = 10(1-p) + 1010p = 10 + 1000p$$

and

$$E[B] = 12.50(1-p) + 212.50p = 12.50 + 200p,$$

where E[·] is the expected-value operator. The expected values of offers A and B are plotted for values of the contingency probability in the chart on the next page. It can be seen that, for $p < 0.003125$ ($\approx 27/8760$), offer A is the better one, while for larger values of p, offer B is the right one. A calculation of the actual probability of using the particular service is the only way to chose between the options. Note that the probabilities do not enter the calculation of the market-clearing price for the service in that hour; the price is determined based on the *actual dispatch*, though the requisite rules are yet to be established. Merit order development methods will be discussed further in the technical group.

Response Update (2000 July 26): Note that probabilistic evaluation will be required only for standby services, and that there will be no market-clearing price for those services.



1. *Question:* Why are forward purchases of supplemental reserves being proposed?
   Response: Such purchases were proposed as a method of facilitating reserves provision by loads, in response to comments made at the December sessions.

2. *Comment:* Formal reviews of the ancillary services procurement process should be conducted on a regular basis.
   Response: ESBI Alberta Ltd. agrees that such reviews are appropriate, and considers them to be part of its mandate. A paper reviewing ancillary services (and other topics) for 1999 has already been prepared.[46] Such reviews arise naturally in the annual tariff application.

3. *Comment:* Rules will be needed for the transition from the current procurement environment to the new one.
   Response: The Transmission Administrator will develop these rules as part of the overall implementation plan.

4. *Comment:* An administratively determined price could be used for constrained on operation.
   Response: The problem with such an approach is that the costs to run these units varies considerably, and for some such a price could be much too high, while for others it could be much too low. The offer price was suggested to be the most appropriate.

5. *Comment:* Ancillary services suppliers could be paid offer prices instead of market-clearing prices.
   Response: The idea behind using the latter is that it encourages suppliers to offer at their marginal costs, knowing that if market prices rise the suppliers will receive the benefit. The use of market-clearing prices also avoids the "winner's curse," wherein the winner feels the offer price must have been too low. This is a fundamental of market systems.
   Response Update (2000 July 26): Market-clearing prices will be used for active ancillary services, while offer prices will be used for standby services. Market-clearing prices are not appropriate for standby services, as discussed in Section 7.

6. *Question:* Why should there be a deployment payment when the provider gets the energy payment?
   Response: While this is true for generators, it is not true for loads that are curtailed in response to a contingency. Also, the pool price may not be adequate compensation for a load whose opportunity cost is its own lost production rather than the price of energy.

[46] See *A Review of the Efficiency of the Management of Ancillary Services, Transmission Losses and Inadvertent Energy on the Alberta Interconnected Electric System in 1999*, which is available on EAL's web site at www.eal.ab.ca.

7. *Question:* What if a load is armed and the price spikes?
Response: Another way of phrasing the question is, must a load remain on at pool prices above that at which it would normally curtail in order to avoid defaulting on an ancillary services obligation? (It is proposed that there be financial consequences for non-performance.) The ancillary services contracts will clearly have to deal with this issue, which will be discussed further in the technical group meetings.

8. *Comment:* Separate the financial settlement from the physical dispatch.
Response: The offer prices are what will establish the order in which dispatch takes place. Complete separation of the physical and financial aspects of ancillary services is not possible.

9. *Question:* Could reserves clear before the energy market?
Response: Yes, this is an option. However, there is a view that spot markets should reflect the price of system security, while the forward markets should reflect the price of energy. The method for establishing the ancillary services merit order, and how that merit order is related to the energy merit order, will be discussed by the technical group.

10. *Question:* What about capacity payments for out-of-merit spinning reserve providers?
Response: The Transmission Administrator has attempted to recognize the need for options on reserves beyond the initial merit order. Providers thereof would be flagged as *standby* and would be paid accordingly.

11. *Question:* What prices will be posted?
Response: While the specifics have yet to be worked out, ESBI Alberta Ltd. supports the greatest possible price visibility consistent with a competitive environment.

APPENDIX C: ANCILLARY SERVICES GROUP TERMS OF REFERENCE

Background

At an EAL stakeholder consultation session held on 2000 January 20, it was suggested that a technical group be created to address the detailed design issues associated with proposed markets for ancillary services. The first meeting of the Ancillary Services Group (ASG) was held on 2000 February 23.

Objective

The objective of the ASG is to develop a "blueprint" for ancillary services markets in accordance with the general principles set out below.[47] The focus will be on the creation of real-time and / or day-ahead markets as foundations for possible forwards or futures markets, recognizing current legislative, technical, and timing constraints. The target date for blueprint completion is 2000 June 1, and the *desired* implementation date[48] is 2001 January 1 or earlier.

Deliverables

The market blueprint will contain recommendations to the Transmission Administrator with respect to:

- the products and services to be transacted, and their associated technical requirements;
- the commercial terms and conditions applicable to sales and purchases, including:
- the structure of bids and offers;
- the mechanics of setting prices and establishing payments;
- the settlement process;
- the dispute resolution process;
- the consequences for failure to perform on purchase or delivery obligations;
- the physical, financial and contractual processes necessary to cause ancillary services to be delivered. These processes will involve the Transmission Administrator, the System Controller, and the entities selling and supplying ancillary services—including Power Purchase Arrangement (PPA) Buyers, the owners of generation units subject to the PPAs, independent power producers, importers, exporters, and loads;
- the determination of the ancillary services dispatch order and deployment rules;
- the coordination of the ancillary services and energy markets.

The ASG will also provide a summary report on the viability of self-provision of reserves, even though this is not strictly a market issue.

Group Membership

Membership in the ASG is open to all interested parties.

General Principles

[The General Principles in the Terms of Reference have been included as Section 6 of this document.]

[47] See also the report entitled *The Acquisition of Ancillary Services in 2001 and Beyond,* which is available on EAL's web site.

[48] The target implementation date will not be determined until the implementation planning stage, which will follow the market blueprint stage.

APPENDIX D: DISCUSSIONS FOLLOWING THE RELEASE OF DRAFT #4

The following items were discussed at the Ancillary Services Group meeting of 2000 May 31 and at the stakeholder consultation session on ancillary services held 2000 June 22. Questions, comments, and responses have been combined and / or paraphrased, without (intentionally) changing the intent, to simplify this summary.

1. *Question:* Why does the Transmission Administrator need Appendix E?
   Response: The intent behind Appendix E was to establish a mechanism to ensure system security in the event that the ancillary services market does not provide adequate resources. In its recent decision on Appendix E,[49]

   > *The [Alberta Energy and Utilities] Board notes … that the System Controller has the capability to compel generators to supply SSS for any amount of SSS that are short of the needed requirements for that hour (or time period). The Board considers that the System Controller's capabilities adequately protect the transmission system during times of SSS emergencies.*

   Given the Board's conclusion, Appendix E has been withdrawn. However, a mechanism for compensating providers under emergency conditions has still to be finalized.

2. *Question:* Is the seller obligated to respond to a call on its standby offer?
   Response: Yes. The seller is paid a premium in return for taking on the obligation to respond if called upon by the System Controller.

3. *Comment:* The Transmission Administrator should publish a range of probabilities of requiring standby in order to return some balance to sellers.
   Response: The Transmission Administrator will make available relevant historical information relating to outages and the utilization of reserves. Suppliers will need to augment this information with their own estimates of the reliance that market participants will place on the standby market to supply replacement reserve for failed supply in order to derive their own estimates of the probability that standby reserve will be required.

4. *Question:* What will be the nature of the *force majeure* provisions contained in the agreement under which the ancillary services market will operate?
   Response: *Force majeure* provisions will be established, with the participation of stakeholders, the Transmission Administrator, and the independent market operator(s), during the contract definition process.

5. *Comment:* The current version of the prototype can cause the Transmission Administrator's portfolio to become too concentrated at a single supply source.
   Response: The ancillary services portfolio selected by the Transmission Administrator for any delivery hour will not necessarily be the one that results strictly from market considerations. Reliability constraints (e.g., a maximum volume of spinning reserve from any single generation unit) will be factored into the resource selection process.

6. *Question:* Is the market readily available to the public and market participants?
   Response: Market participants will have access to the market and to trading screens. The public normally does not have such access, although market summaries will be provided for proper public disclosure.

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[49] Decision 2000-46, *ESBI Alberta Ltd., 2001 General Tariff Application, Phase I & II, Part A: System Support Services - Thermal Power Purchase Arrangements (Appendix E)*, page 15.

7. *Comment:* Contract design must be balanced, favoring neither buyers nor sellers.
Response: All exchange-based contracts are developed on the basis of achieving reasonable balance and fairness between buyers and sellers. The structure of the market as proposed has considered this element foremost in its selection of:
   - the equilibrium pricing mechanism, which provides for equivalent access by large and small suppliers with little discrimination in timing and size of offer;
   - the five-day trading schema, which provides the dominant captive buyer the opportunity to attract competitive offers as suppliers will not know in which day purchases will be made;
   - the integration of, and the opportunity to arbitrage between, the energy and ancillary services markets through the indexed price option and the coordination of market closings;
   - the requirement for the Transmission Administrator to purchase its complete forecast requirements, which provides a commitment to the forward (five-day) market that will encourage sellers to provide competitive offers.

8. *Question:* Who appoints the market operator?
Response: Stakeholders have recommended that the Transmission Administrator contact a number of potential third-party market operators to determine their interest in providing systems and services for the trading of ancillary services.

9. *Question:* What role does / should the AEUB play in dispute resolution?
Response: The Transmission Administrator prefers to utilize normal market mechanisms for dispute resolution, and expects that mediation / arbitration will be incorporated within the contracts developed by the market operator(s). The operator(s) should be independent and operate in the best interest of a fair market, and should normally act as the mediator for disputes. Arbitrators are generally peers from the marketplace that resolve disputes that cannot be mediated. Most exchanges do not allow for any dispute resolution beyond arbitration, and as such would not provide for referral to the courts or other regulatory agencies. It should be noted, however, that the Transmission Administrator's overall management of ancillary services would remain under the jurisdiction of the AEUB.

10. *Question:* The code of conduct is defective in offsetting market power concerns.
Response: The rules and procedures for the ancillary services market will be developed with consideration for the effectiveness of the pending *Regulated Supplier and Retailer Code of Conduct.* However, it is not within the Transmission Administrator's mandate to change that code.

11. *Question:* What is the purpose of standby pricing?
Response: As outlined in Section 7, the purpose of the standby market is to provide certainty that replacement resources are available and obligated to supply when active resources become unavailable.
The bids and offers for the standby market will include two price components: one for acquiring the right to call for a service and a second as the payment for actually providing the service if activated. The premium paid for acquiring the right to call for a service acknowledges that the supplier undertakes an obligation to provide a service that may be called on at a future point in time. The price paid for activation acknowledges that suppliers to the standby market have opportunity costs in the event that the provision of reserves is requested.

12. *Question:* Why would the activation price for standby be anything other than the real-time energy price?
Response: The activation price being offered by a supplier should be a reflection of its opportunity cost to provide an ancillary service. Particularly for supplemental reserve and for spinning reserve provided by hydro, the real-time energy price is not necessarily a good proxy for the opportunity cost incurred when providing reserve.
The real-time energy price is currently determined *ex post*, and does not allow the Transmission Administrator a reasonable opportunity to control its market price exposure. It is imperative that the activation price be set in advance so that the TA can assess the various offers against the probability of use and to structure the merit order to call on these suppliers as required. By compensating at the real-time energy price it would not be possible for the TA to make prudent advance purchases of these services.
The Transmission Administrator will require the activation price component to be offered in as a firm exercise price. This will provide for transparent market competition, permit proper merit order stacking, and allow for arbitrage between day-ahead energy, active ancillary services, and standby ancillary services.

13. *Question:* Should the Transmission Administrator have the ability to simply pass on costs?
Response: The Transmission Administrator is prepared to support the competitive market-based procurement mechanism outlined in this document by incorporating these purchases within its proposed incentive scheme. Under that proposal, EAL is prepared to risk up to $1 million annually on the cost of ancillary services as

measured against a Board-approved benchmark. Please refer to Section 3.4.2 of *ESBI Alberta Ltd., 2001 General Tariff Application, Phase I and Phase II,* Alberta Energy and Utilities Board Application 2000135.

14. *Question:* Is the self-supply of ancillary services viable?
Response: The Transmission Administrator will not provide for the self-supply of ancillary services on January 1, 2001. However, depending on the overall performance and success of the new markets structure, the Transmission Administrator will re-examine this issue in consultation with its stakeholders on an ongoing basis.

15. *Comment:* The liability provisions in the existing contracts for reserve from loads are too onerous.
Response: These provisions were recently changed. As noted in Section 2, the liability obligations should be severe enough to encourage performance on contracts, but not so severe as to discourage participation in the market.

16. *Question:* What happens when a facility that is "in merit" is prevented from performing its ancillary service contract obligations by external forces (e.g., transmission line capacity limits)?
Response: The *force majeure* provisions in the ancillary service contracts will set out the conditions under which suppliers will not be held accountable for the performance of their obligations. Such conditions will include those where transmission system conditions beyond suppliers' control affect their ability to deliver the contracted services.

Note that the Transmission Administrator is bound by the market-based contracts it enters into, just as suppliers are. Clearly it would be inefficient for the Transmission Administrator to enter into a contract for ancillary services if it had advance knowledge that delivery would be impossible, due, for example, to transmission line maintenance.

APPENDIX E: POWER POOL COMMENTS ON THE MARKET DESIGN

The Power Pool of Alberta wrote to the Transmission Administrator on 2000 June 2 to provide its comments on energy and reserves market coordination. An annotated copy of the Pool's letter and the Transmission Administrator's response follow. (Note that formatting changes occurred as a result of the letters' incorporation into this document.)

ESBI ALBERTA LTD.
TRANSMISSION ADMINISTRATOR

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26 July 2000

Power Pool of Alberta
McFarlane Tower
1800, 700 - 4 Ave SW
Calgary, Alta T2P 3J4

Attention: Ms. Cheryl Runge

Dear Cheryl:

RE: Energy and Reserves Market Coordination

Thank you for your letter of 2000 June 2 on the coordination of the energy and reserves markets. I appreciate your taking the time to review and comment on the ancillary services market proposal from the "energy market" perspective. I believe most of the issues raised in your letter have since been resolved through a better understanding of, or refinements to, the ancillary services market proposal. However, to continue with the practice established in *The Acquisition of Ancillary Services in 2001 and Beyond* of recording and addressing comments submitted by stakeholders, I will "close the loop" by addressing the points you raised in your letter.

For ease of reference, at various points in your letter (a copy of which is attached) I have inserted numbers that refer to the comments that follow.

1. Competitive Procurement of Regulating Reserve

EAL believes that competitive procurement of regulating reserve is appropriate. The volume of such reserve available on the AIES is typically several multiples of the hourly requirement. During those periods when the supply does become limited, prices should rise and the entry of new suppliers should be encouraged. The result, over the long term, should be better prices and improved reliability due to the increased supply.

In light of the Alberta Energy and Utilities Board's recent ruling on Appendix E to EAL's 2001 transmission tariff terms and conditions,[50] competitive procurement is essentially the *only* option available to the Transmission Administrator except under emergency conditions. While competitive alternatives to an hourly market (e.g., requests for proposal) do exist, they are not as adaptable to real-time conditions.

2. Load Following

The question of whether suppliers will be able to meet the technical specifications for load following can be addressed by noting that: (a) in practical terms the service is already being used; (b) there are suppliers that have demonstrated both the willingness and the capability to provide the service; and (c) the service is used in several jurisdictions in the United States and is recognized by the Federal Energy Regulatory Commission (FERC) as an ancillary service.

My understanding of current practice, based on discussions I had with system operators during a visit to the control centre, is that load following requirements are met in two ways. The first is to dispatch "ramp rate." That is, the operator may dispatch units that are farther up the energy merit stack than is necessary strictly from an energy market perspective in order to achieve the ramp rate necessary to follow changes in generation and load. This "above-merit" dispatch may cause pool price to rise, thereby increasing the price

[50] Decision 2000-46, *ESBI Alberta Ltd., 2001 General Tariff Application, Phase I & II, Part A: System Support Services - Thermal Power Purchase Arrangements (Appendix E).*

of all of the energy being exchanged through the Pool at that moment. Paying explicitly for load following capability as an ancillary service should have the effect of damping the pool price rise caused by the ramp rate dispatch. If suppliers demand prices above the extant energy price to provide load following, then at least those higher prices will apply to a limited-volume service and not to all AIES energy.

The second way in which load following is currently provided is by dispatching additional AGC and / or by dispatching AGC units to their high or low limits in anticipation of load, generation, or tie line ramps. EAL expects that it will be more expensive to acquire load following from AGC-capable units than from other units.

3. Acquisition Principles

This oversight has been corrected.

4. Market Design Principles

EAL appreciates the Pool's support of these principles, which have long been a part of the Transmission Administrator's market philosophy. EAL has not adopted the term "rational buyer," however, because it is superfluous, adding nothing to the procurement processes that have been in place in Alberta for some time. The term refers to a buyer that meets its requirements for a lower-quality service (e.g., supplemental reserve) with a higher-quality service (e.g., spinning reserve) whenever the higher-quality service is cheaper. The alternative, which in this case would be to buy supplemental reserve in place of less expensive spinning reserve, has never been considered by EAL.

The rational buyer concept has been evident for some time in WSCC operating reserve criteria, which state that *at least* 50% of required operating reserve must be spinning. That is, the option exists under those criteria to purchase extra spinning reserve in place of supplemental reserve when it is beneficial to do so. In addition, the Transmission Administrator's operating policies incorporate the essence of the rational buyer model in that, for example, "excess" spinning reserve is used to reduce the quantity of supplemental reserve required.

Cascading markets follow logically from rational buying decisions. The coordination of the closings of the energy and ancillary services markets is required to allow suppliers to manage their energy and ancillary service portfolios and to ensure the efficiency of the electricity market as a whole.

5. Co-Optimization in Today's Market

EAL recognizes that system operators use their knowledge and experience in an effort to dispatch resources in the most economically efficient manner possible. However, taking "optimized" in the context of your letter to mean that there are *no dispatches whatsoever* that would result in a lower combined cost of energy and reserves—a definition that is consistent with the definition of "co-optimized" in your June 12 BDAM paper—one might be left with the impression that some kind of sophisticated cost minimization algorithm is being employed today. To the best of EAL's knowledge, there is no process in place by which the System Controller selects the least-cost option from a series of technically acceptable dispatch scenarios whose costs have been computed in advance.

The Transmission Administrator's ancillary services market proposal substitutes market-based optimization for the subjective optimization that is in place today. This in no way minimizes the importance of the operators in determining ancillary service requirements based on system conditions.

I discuss optimization further in Point 7 below.

6. Market Details

I trust that the Operational Walkthrough section of the most recent version of *The Acquisition of Ancillary Services in 2001 and Beyond*, together with our recent meeting on market co-ordination, have provided the details you require.

7. Future Co-optimization of Energy and Ancillary Services

Your statement that the System Controller would dispatch the ancillary services and energy markets separately (i.e., with no co-optimization) is correct, but it could be misinterpreted. Echoing my concern in Point 5 above, it is important to note that, given compatible energy market and ancillary services market rules, competitive forces and suppliers' portfolio management options will lead to the desired economic efficiency. That is, the competitive markets themselves will drive economic optimization without the need for either the Transmission Administrator or the System Controller to perform any algorithmic ("black box") optimization.

There are several other points I would like to make with respect to optimization, to wit:

- The design of the ancillary services market, including its timing relationship to the energy market, will allow arbitrage to occur. Arbitrage is important from a market efficiency perspective.
- EAL expects that the majority of ancillary services will be procured in advance of real time. Assuming that significant volumes of energy also transact in advance of real time and that generators are responsible for their own unit commitment decisions, there will be limited opportunity for a real-time co-optimization process to take place.
- Algorithmic optimization of energy and reserves is more open to gaming than the market-based alternative.[51]
- Algorithmic optimization generally attempts to minimize costs across multiple time periods, often the 24 hours in a day. This daily, inter-temporal optimization may shift costs among hours, thereby reducing participants' incentives to adapt their operations to certain hours. In addition, inter-temporal optimization requires central dispatch decisions to ensure that resources are on line when required by the optimal schedule, and is therefore not compatible with generator self-commitment.
- Optimization based on anything other than the market itself requires that either the Transmission Administrator or the System Controller undertake a "central planner" function. EAL's stakeholders have clearly expressed their aversion to such a function. Stakeholders have also stated their preference for transparent, market-based solutions over "black box" alternatives.

[51] "The efficiency of such a system [unbundled energy and reserves] may seem counterintuitive, since it makes no attempt to optimize jointly the energy and reserves markets. However, it is precisely this joint optimization—selecting energy and reserve resources to minimize total system costs—that creates the incentive for bidders to distort their bids, undermining efficiency." Cramton, Peter, and Robert Wilson, *A Review of ISO New England's Proposed Market Rule,* 1998 September 9, pp. 36. The paper is available at the University of Maryland web site at www.cramton.umd.edu.

8. The Release of Reserves into the Energy Market

The Transmission Administrator fully supports the notion that reserves (except regulating reserve) should be released during supply-constrained situations before firm load is shed. This is consistent with existing practice as set out in Transmission Administrator Operating Policy (TAOP) OP-700, which has been in place since 1998 November 24.

The ancillary services market proposal provides for the release of supplemental and spinning reserves into the energy market when energy prices rise to the respective price caps. In our meeting of July 18, you and Dale said a release mechanism might be required in the event that the energy supply has been exhausted but the price has not risen to those levels. If the energy market rules ultimately permit such an event, EAL will adapt the reserves release mechanism accordingly.

9. Provision for the Real-time Acquisition of Reserves

The ancillary services market model recognizes that the ability to call on additional or replacement resources in real time is critical to the System Controller, and it provides that ability through the standby queue. To acquire resources in real time, the System Controller will exercise one or more of the "call options" sold to the Transmission Administrator by standby suppliers. Note that, while ancillary service options can be exercised in real time, the price is not set then; instead, it is determined in advance through the Transmission Administrator's forward standby purchases.

10. Purchases at Any Price

It is not true that "all SSS will be forward purchased *at any price*" (emphasis added). Initially, and for as long as there is a price cap in the energy market, there will be a cap on ancillary service prices. Following elimination of the cap, and perhaps before, it is appropriate that the Transmission Administrator examine the possibility of creating a demand curve for ancillary services to avoid the excessive price spikes associated with inelastic demand. The creation of a demand curve is, however, a complex process that must be undertaken with the significant involvement of stakeholders and the Alberta Energy and Utilities Board.

11. Real-time Buyer

The Transmission Administrator is mandated by legislation, and is expected by stakeholders, to make prudent financial arrangements for ancillary services. It is also in the interest of a fair and orderly market that the Transmission Administrator meets market participants' expectations that it will buy the required volumes of active and standby reserves at market prices. Thus, it is EAL's intent to purchase its full complement of reserves, subject to forecast tolerances, by the close of the forward trading sessions. Note that, eventually, the purchase volumes may also be subject to the influence of the demand curve discussed in Point 10.

The System Controller's role in real time is to dispatch active ancillary service resources and, if necessary in real time based on system conditions, to execute the call options pre-purchased by the Transmission Administrator (i.e., dispatch resources from the standby market).

12. Incentive to Sell Ancillary Services in Advance of Real Time

The incentives to sell ancillary services in advance are much the same as the incentives to sell energy in advance and include, in particular, the ability to lock in prices. In addition, operating in both forward energy and forward ancillary services markets provides suppliers with portfolio management and resource optimization options that do not exist if they forgo participation in either of those markets. Waiting until after the energy market closes may result in lower revenues, or perhaps no revenues at all because the Transmission Administrator has already purchased its required reserve volumes.

13. Opportunity-Based Compensation

EAL does not support the concept that an energy-related opportunity cost be used to compensate suppliers of standby ancillary services. Suppliers' opportunity costs are not necessarily related to the price of energy. This is particularly true of interruptible loads providing supplemental reserve, whose opportunity costs are more likely to be related to the value of lost production. It is also true, however, in the case of fuel-constrained generation such as run-of-river hydro. The Transmission Administrator believes that suppliers are in the best position to determine their opportunity costs and to reflect them in their ancillary service offers.

A stock market analogy to the standby market is provided by the sale of a call option. The seller receives a premium in return for giving up its claim on profits from stock price rises above the agreed strike price. In the standby reserves case, suppliers receive a premium in return for releasing their claim on profits from rising energy prices (in addition, of course, to having to provide the service if called).

14. Out-of-Merit Standby Resources

EAL has no objection to flagging those "out of merit" in the standby market as willing reserve providers. It should be noted, however, that they would only be called under emergency conditions, i.e., at times when the standby queue has been exhausted by a series of contingencies.

15. Premiums at Zero and Activation Prices at the Price Cap

A participant that offers a standby premium of zero and an activation price at the cap may well be eliminated from the standby merit order. It must be remembered that both prices are used in the probability-weighted calculations that determine which suppliers will be selected to provide standby reserves. On the other hand, if the expected cost of using that participant is lower than that of alternate suppliers, the Transmission Administrator has no objection to zero premiums.

16. Strike Price at the Reserves Market Clearing Price

It might be argued that a clearing price in the standby market would be more consistent with the active reserves market than would be the payment of offer prices. The fundamental difference is that standby providers are selling options, and must assess for themselves the probability of being called and the implications (e.g., lost production) thereof. Different participants are likely to make different assessments that, together with opportunity cost information, constitute information critical to pricing decisions. In addition, there is a strong link—embodied in many mathematical models, the best known being the Black-Scholes model—between an option's strike price and its premium. Setting a market-clearing strike price inappropriately severs that link. Finally, an option with a strike price that is set after the purchase has been agreed to is of no value, and the associated premiums would therefore necessarily be zero.

17. Market Operator

From EAL's perspective, particularly in light of the Pool's decision not to develop the Binding Day Ahead Market, the Pool is not a candidate to operate the ancillary services market.

Thank you once again for your comments, and also for your contributions to the ancillary services market design effort.

Yours truly,

i) TRANSMISSION ADMINISTRATOR OF ALBERTA

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June 2, 2000

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Dear Randy:

RE: ENERGY AND RESERVES MARKET COORDINATION

Thank you for the opportunity to meet to discuss market coordination questions between the reserves and energy markets. I have reviewed your Discussion Paper, Draft # 4 as well as your proposed section on "Interaction with the Energy Market" and have the following comments. My comments have been sorted into general market design observations separate from market coordination items that we need to discuss further.

TA Market Design Proposal – General Observations:

- The Power Pool of Alberta fully supports a competitive procurement process for ancillary services where practical. However, we remain uncertain as to need for competitive procurement for regulating reserve given limited supply alternatives. **[1]**
- There is an ongoing assessment as to the need for load following given depth in the merit order. The Power Pool has committed to work with EAL to better assess the need for a load following service and to implement a pilot program. One of the concerns is whether suppliers will be able to meet the technical specifications required to provide load following services. **[2]**
- The "principle" of working with the Power Pool to coordinate the design and operations of the DA energy and markets for SSS is still missing from section six ("Ancillary Services Acquisition Principles.") **[3]**

Market Coordination – Comments and Issues:

The TA's market design proposal has incorporated a number of principles that the Pool has presented and discussed at the working group meetings over the last couple of months (i.e., rationale buyer, cascading markets, coordination of market closings). **[4]** While I have a number of comments about the details in your proposal which I can provide directly on the draft "market interaction" document, the following represent the main items which I think we still need to discuss and understand further.

1. Impacts of Forward Positions in Real-Time Market:

   In today's market, the TA contracts forward for reserves and a co-optimization occurs in Real-Time **[5]** to, in essence, integrate the reserves and energy products. The Power Pool of Alberta fully supports the concept of forward contracting for reserve services but we must ensure the arrangements provide the proper incentives in all markets. We think this goal is achievable but the current documents do not provide the details we require. **[6]**

   Under the May 18 Ancillary Services Market proposal, the TA would buy forward its reserve requirements, overlapping the BDAM timeline to allow participants to close out any open reserve positions. The final positions resulting from the SSS market are then passed to the System Controller to be dispatched in Real-Time. The System Controller would dispatch the SSS and energy market merit orders separately (i.e., with no co-optimization). **[7]**

In order to understand fully how this is intended to work, I think we should meet to walk through some examples of how the TA's forward "call energy" position would be envisioned to be applied in Real-Time. For example, during supply constrained situations we need to clearly understand if and how units in the SSS market would be released into the energy market to produce energy. ***[8]*** *It is imperative that the forward positions for reserves do not impose further inflexibility on the system management by the System Controller.*

2. "Mandatory" Reserves Market:
It is my understanding that the Ancillary Services market design model has no provision for Real-Time acquisition of System Support Services. **[9]** In essence, it is envisioned that all SSS will be forward purchased at any price **[10]** to fulfill the merit order requirements for Real-Time. I would like to further understand the default position to this proposal.

While the five day forward buying portfolio concept theoretically compensates for the "single buyer" exposure, sellers still know that the TA is mandated to meet its requirement criteria prior to Real-Time. Will the TA pay ANY price for reserves to meet this criteria? **[10]** If the criteria is not met at the close of the forward trading session, will the System Controller become the Real-Time buyer of SSS on behalf of the TA? If so, what mechanism will enable this? **[11]** What incentive does a participant have to provide forward reserves prior to the energy market when they can simply wait until after the energy market clears, knowing that reserve requirements must be met? **[12]**

3. Activation Flag and Price for Stand-by:
Similar to the point raised in item 2 above, for system management purposes it is necessary to establish the rules around meeting SSS requirements in Real-Time potentially by going to the energy market. The TA proposal includes the provision for "stand-by" services as an avenue to meet these needs. In order to provide depth and fairness to the stand-by market, it is recommended that a couple of changes be made to the market proposal.

First, the Pool proposes that the activation price for stand-by be set at the opportunity price in the energy market. Participants who are in the stand-by market are, by choice or as a result of bidding behavior in the active reserves market, in the energy market (in most cases). Accordingly, to activate stand-by participants for the reserve market, they should be paid their lost opportunity for leaving the energy market. This principle additionally adds depth to the stand-by market as any energy market participant willing to provide reserves could be taken from the energy market to do so at an appropriate compensation. **[13]** To this end, it is proposed that those "out of merit" from the stand-by market also be flagged as willing to provide reserves. **[14]**

Clearly, there are other ways to compensate activation of stand-by providers; however, the alternatives create perverse incentives. For example, the current proposal creates an incentive for a participant to bid "zero" to provide stand-by with an activation price at whatever the price cap is. **[15]** Alternatively, the strike price could be at the clearing price of the reserves market. However, because they are in effect "out of market" for reserves, this may be perverse as well. **[16]**

4. Reserves Market Operator:
We should talk further about the market operator for the SSS market as well. To the extent that the Pool operates a BDAM and to the extent that the System Controller becomes the defacto Real-Time operator of the reserves market, there are efficiencies for the Pool to also operate the reserve market. Additionally, to consider alternative private sector operators for the BDAM, as mentioned at the meeting, we have made contacts with a number of interested forward energy market operators. Perhaps, you would be interested in making these same contacts as part of your analysis for the SSS market. **[17]**

We should meet to sort out these global issues regarding market coordination. Additionally, I will provide a draft version of the joint document using your draft as a starting point.

Yours truly,

Power Pool of Alberta

Cheryl L. Runge

BDAM Project Manager

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