# REACTIVE POWER AS AN IDENTIFIABLE ANCILLARY SERVICE

*prepared for*

**Transmission Administrator of Alberta, Ltd.**

*by*

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**March 18, 2003**

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# EXECUTIVE SUMMARY

This report examines the concept of reactive power as an ancillary service with its own compensation and charges. Its purpose is to help Alberta determine "if there is merit in creating a separate unbundled tariff mechanism for the revenue and cost allocation of reactive power as an identifiable Ancillary Service." Our perspective is that Alberta should aim to procure reactive power in a way that results in the most efficient investments in and dispatch of reactive power resources, including both generation and non-generation resources. From this perspective, the question of "unbundling" is really a question of resolving several important policy issues concerning market participants' obligations to provide or pay for reactive power. Fortunately, both the literature and the experience of other power systems provide many ideas about how these questions might be resolved.

## ES.1. Survey of Literature on Pricing of Reactive Power

With few exceptions, the literature proposes to base reactive power prices on reactive power costs. Consequently, there is a considerable portion of the literature that is devoted to identifying and quantifying reactive power costs.

Much of the literature on reactive power pricing builds on the theory for optimal locational pricing of real power. Consequently, a major strand of literature proposes that reactive power prices be set on a locational (nodal) spot basis. The pricing of reactive power would thus be virtually identical to the way that New York and the Pennsylvania—New Jersey—Maryland Interconnection (PJM) presently price *real* power on a locational hourly basis. Such an approach has some important theoretical strengths, as well as important practical limitations.

Many authors propose other pricing methods, some of which can be implemented in conjunction with the locational spot pricing framework. On the supply side, these include proposals for separately pricing different categories of cost (e.g. capability, utilization) or resources (e.g. static supply, dynamic supply), for long-term supply arrangements, and for setting penalties for failure to supply reactive power as promised or required.

Other literature provides proposals for paying generators and charging consumers. Some of these proposals are based on the locational spot pricing framework, while others are not. Many of these proposals are *ad hoc*, reflecting no engineering or economic theory, but merely aiming to achieve the practical goals of full cost recovery and simplicity of market arrangements and rate design.

The solutions that are most efficient in theory tend to be impractical to implement, while the solutions that are practical to implement tend to suffer important inefficiencies. Moreover, most of the cited articles were published at a time when there was high optimism for market solutions, and relatively little concern for the market power problems that must inevitably plague some of the proposals.

## ES.2. Survey of Other Jurisdictions' Treatment of Reactive Power

We summarize the reactive power market design and pricing policies of several power systems in which generation ownership has been separated from system control. We focus on the markets of New Zealand, the U.K. (England and Wales), and five U.S. Independent System Operators (ISOs): California, New England, New York, PJM, and Texas. For additional breadth, we also present some of the findings of two published surveys.

The discussion is divided in five parts. The first part looks at how reactive power service is defined, and though it finds no standard definition, there does seem to be a common understanding of what the service is. The second part briefly summarizes how system operators determine system reactive power needs and dispatch reactive power resources.

The third part describes the reactive power capability requirements that generators are expected to meet. All markets have some rules that indicate the minimum range of reactive power capability (often expressed as a power factor capability range) that generators must provide as a condition of interconnection or market participation. For the power systems that we have examined, lagging power factors vary between 0.85 and 0.95 while leading power factors are all 0.95. All markets also have rules that specify how well generators are expected to follow the system operator's reactive power dispatch instructions. These instructions are often given in the form of specified voltage setpoints.

The fourth part explains how resources are paid for the reactive power service that they provide, and finds that there is no standard methodology. There seems to be a growing consensus that generators should be paid for their opportunity costs of producing reactive power instead of real power – that is, for their lost profits on foregone sales of real power. There is not much consensus about how to set prices for the non-opportunity cost portion of variable costs or for reactive power capacity.

The final part discusses the various ways that reactive power costs are recovered from customers. It begins by summarizing the findings of two surveys of reactive power cost recovery, one by Alvarado *et al* [1996] and the other by Dingley [2002]. It then directly reviews the cost recovery methodologies of several regional power systems. In short, restructured markets recover reactive power costs that are set sometimes according to payments to reactive power resources, and other times according to administratively determined levels. Long-term (capacity) costs are sometimes recovered separately from short-term (variable) costs. Most costs tend to be recovered through per-MWh charges on all loads, but they are also recovered through charges on reserved (nominated) or actual peak kVAr demand or through kVArh charges. Some of these charges are applied only to reactive power consumption above a base level.

## ES.3. Options for Unbundling Reactive Power Service in Alberta

Whether there is merit in unbundling depends primarily upon whether (and how well) unbundling can help Alberta obtain needed investment in reactive power equipment and induce efficient real-time dispatch of its stock of reactive power equipment. If Alberta's present market structure has resulted or threatens to result in deficient reactive power investment or inefficient dispatch, unbundling might help resolve the deficiencies.

Other factors that might be considered as drivers for unbundling are fairness concerns and government policy in encouraging market structures over regulatory structures. "Fairness" would allow generators a reasonable opportunity to fully recover the costs of the reactive power services that they provide, and would give consumers a reasonable chance of eventually seeing lower reactive power costs. Government policy should seek a combination of market structures and regulatory structures that eventually lead to the greatest consumer benefits (in the forms of better service and lower prices).

Although we have not examined the specific physical configuration of Alberta's power system, we are fairly certain that the system will not support short-term competition in reactive power service, where "short-term" is the period before which new reactive power resources can come on-line. Nonetheless, because we have neither examined Alberta's data nor conducted quantitative analysis of the province's power system and tariffs, we are presently not able to determine whether Alberta's present reactive power arrangements merit reform.

If Alberta *does* make such a determination, however, we recommend that the reform include nine basic elements. The elements related to the supply of reactive power by generators are as follows:

1. *Minimum reactive power capability requirements*. As a condition of market participation, on-line generators would be required to provide a minimum level of reactive power service through automatic devices. This minimum requirement would allow some level of non-performance due to normal maintenance requirements and outage risks. Generators that cannot satisfy the minimum requirement would be charged for the value of the reactive power service that must instead be provided by other resources.

2. *Availability requirement*. As a condition of market participation, generators would be required to schedule maintenance so that they can provide reactive power at critical times (if any). They would also be required to be available to produce reactive power at an acceptably high reliability level that would be demonstrated through a testing procedure.

3. *Penalties for non-performance*. When generators fail to meet their obligations or to follow TA instructions, they would pay penalties. The TA would establish a testing procedure for determining whether generators meet the minimum reactive power capability requirements and the availability requirement.

4. *Compensation for capital costs*. If the Transmission Administrator (TA) asks generators to make investments that extend their reactive power capabilities beyond the minimum, the TA would provide compensation for the costs of the incremental capability. This compensation would give the TA the right to dispatch the generator's reactive power, with additional compensation for variable costs.

5. *Compensation for variable costs*. The TA would compensate generators for their variable costs (including opportunity costs) in two situations. First, when instructing generators to provide reactive power beyond minimum requirement levels, the TA would compensate generators for the variable costs incurred due to going beyond the minimum. Second, when committing generators so that they can provide reactive power or reactive power reserves, the TA would compensate generators for start-up costs and otherwise uncompensated costs (such as minimum loading costs).

6. *Transmission Administrator resources*. The TA should have the right to procure and manage its own reactive power equipment – or to direct Transmission Facility Owners

(TFOs) to do so – in cases wherein the preferred resources are not available from generators and other market participants. This right is needed to mitigate generators' potential exercise of market power in the long-term reactive power market, which it accomplishes by making substitute resources available to the TA. The TA should be required to justify such investments by demonstrating that either: a) the needed resources are not available from non-TFO parties; or b) the TA is capable of procuring the resources (or the resulting reactive power services) more cheaply if it does so directly (or through TFOs) rather than through non-TFO parties.

The elements concerning recovery of the costs of reactive power service, including costs from both generation and non-generation sources, are as follows:

7. *Charges for direct reactive power consumption*. For using reactive power outside of a standard power factor range, the customer should pay a charge based upon some combination of peak kVAr and total kVArh consumption. This approach would provide incentives for customers to install their own reactive power compensation equipment.

8. *Special voltage charges*. When a market participant's behavior or characteristics creates significant voltage control costs, it may be appropriate to levy a special charge on that participant. Circumstances that can create such special voltage needs can include: a) rapidly varying production or consumption of real power; and b) participant locations not readily reachable without special reactive power compensation schemes.

9. *Uplift charges*. For all reactive power and voltage control costs that are not recovered through the two preceding charges, there would be an uplift charge. These costs are primarily associated with the need to provide reactive power throughout the system to support real power flows.

Alberta's "options" for unbundling lie in the choices that can be made in implementing each of these elements.

# REACTIVE POWER AS AN IDENTIFIABLE ANCILLARY SERVICE

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Reactive power has a profound effect on the security of power systems because it affects voltages throughout the system: deficiencies of reactive power cause voltages to fall, while excesses cause voltages to rise. Voltages that are too high or too low can result in increased power system losses, overheating of motors and other equipment, and system voltage collapse with consequent loss of customer load. Indeed, many major outages have been ultimately traced to problems with insufficient reactive power support. Furthermore, insufficient reactive power at key locations in the system can result in the inability to transfer active power beyond a level that is often well below other system limits.

Although the costs of reactive power that is provided by transmission and distribution facilities can be recovered through traditional cost-of-service ratemaking mechanisms, the means by which generators can recover their costs of reactive power is not so clear. Because a growing number of Alberta's generators have revenues that are determined by market forces, they will not want to provide reactive power unless market rules require them to do so or they are rewarded for doing so. Consequently, for Alberta to continue to obtain reactive power services from generators, it must decide on the terms and conditions under which generators will provide these services.

With this necessity as its motivation, this report examines the concept of reactive power as an ancillary service with its own compensation and charges. Its purpose is to help Alberta determine "if there is merit in creating a separate unbundled tariff mechanism for the revenue and cost allocation of reactive power as an identifiable Ancillary Service." Our perspective is that Alberta should aim to procure reactive power in a way that results in the most efficient investments in and dispatch of reactive power resources, including both generation and non-generation resources. From this perspective, the question of "unbundling" is really a question of resolving several important policy issues concerning market participants' obligations to provide or pay for reactive power. Fortunately, both the literature and the experience of other power systems provide many ideas about how these questions might be resolved.

The organization of this report is as follows. Section 1 presents a bit of background on the present and prospective reactive power situation in Alberta. Section 2 provides an overview of the literature on reactive power pricing and market organization, most of which has been concentrated in engineering (rather than economic) forums. Section 3 surveys the reactive power markets in New Zealand, England and Wales, and five regions of the U.S. It also includes summaries of two published surveys of reactive power pricing practices.

From the surveys of Sections 2 and 3, Section 4 distills those ideas that seem most practical for implementation in Alberta. Because we have neither examined Alberta's data nor conducted quantitative analysis of the province's power system and tariffs, we make no recommendation concerning whether Alberta should actually unbundle reactive power service. Nonetheless, we provide specific unbundling options that Alberta might consider if it does choose to unbundle.

## 1. REACTIVE POWER ISSUES IN ALBERTA

Different parties appear to have different opinions about the significance of Alberta's present and future reactive power problems; but there does seem to be agreement that such problems exist. For example, there seem to be reactive power problems with some particular facilities or locations, such as the North-South corridor. As another example, wind generators may pose significant voltage problems that will require installation of synchronous condensers, STATCOMs, and static VAr compensators (SVCs) for the purpose of managing voltage levels in the vicinity of wind farms.[1] There is also a concern that, as areas of Alberta's power system become congested, additional reactive power support will be required and issues may arise concerning how such support will be procured. Most of this support could likely be procured through installation of static devices such as capacitor banks or SVCs.

Furthermore, Southern Alberta has allegedly been at threat of voltage collapse in recent years, and thus an Under Voltage Load Shedding scheme has been armed in the Calgary area. With increasing load growth in the South and increasing export needs through the BC tie line, there may be an increasing need for dynamic voltage control requirements for existing and proposed plants in Southern Alberta.

Particularly relevant to the issue of unbundling is that fact that Alberta relies upon generators for reactive power support. The Interconnection Requirements of the Transmission Administrator (TA) of Alberta (backstopped by the TA's tariff) stipulate that generators be capable of producing and absorbing reactive power within a 0.90 lagging and 0.90 leading power factor range.[2] Alberta apparently obtains additional voltage support from generators through programs involving location-based credits and transmission must-run schemes. In addition, consistent with the Western Electricity Coordinating Council (WECC) requirements, generators must be equipped with automatic voltage regulators (AVRs) on automatic voltage control mode and with power system stabilizers (PSS).

Generators accept direction from the system controller to adjust VAr output for voltage control purposes as long as the direction is within their capabilities. The signal received from the system controller is often in the form of a voltage regulation setpoint, which indirectly gives a signal to the generator to *adjust* its reactive power output rather than a signal that directs the generator to *produce a specific amount* of reactive power. Financial penalties are levied in the event of non-compliance, including non-compliance assessments by the WECC that are enforced through the Reliability Management System (RMS) contract that was signed by the TA and approved by the regulator. The generator is subject to a financial penalty if the generator fails to maintain its AVR/PSS in the appropriate state under the terms and conditions of the TA's tariff.

[1] Wind farms, particularly those powered by induction generators, are very bad from the perspective of reactive power and voltage regulation. Not only do induction generators absorb instead of supply reactive power, they also are unable to regulate the voltage at their location. Wind farms *could* use generators other than induction generators, but this would increase their costs and/or make their design and deployment more difficult.

[2] Some older generators are not able to meet the 0.90/0.90 power factor requirement.

Different parties appear to have different opinions about the extent to which the TA needs generators to operate beyond the power factor range expected for normal operation and the extent to which the TA pays generators for providing voltage support. The TA pays one generation firm to provide voltage support by operating its hydro units in synchronous condenser mode ("hydro motoring"). It has two other contracts by which generators provide regional voltage support by operating synchronous condensers that are coupled to gas turbine shafts. The two generators that are coupled to synchronous condensers also provide "transmission must-run" service for reliability. Some parties cite additional cases in which the TA needs voltage support, beyond minimum needs, from generators.

The TA recovers the costs of voltage support through a per-MWh transmission charge that is recovered half from supply customers and half from demand customers. The charge is in the form of a percentage charge on energy valued at the pool price.

## 2. SURVEY OF LITERATURE ON PRICING OF REACTIVE POWER

With few exceptions, the literature proposes to base reactive power prices on reactive power costs, where "costs" may be determined directly or through market processes. Consequently, there is a considerable portion of the literature that is devoted to identifying and quantifying reactive power costs. This is the first topic that we discuss in this survey.

Much of the literature on reactive power pricing builds on the theory for optimal locational pricing of real power. Consequently, a major strand of literature proposes locational spot pricing of reactive power. Such locational spot prices would serve as at least *part* of the basis for paying generators and charging consumers for reactive power. This approach has its limitations, however, so much of the literature is also concerned with addressing these limitations. This approach, as well as its extensions and limitations, is the second topic that we consider.

The third and fourth topics we review are, respectively, other proposals for paying generators and charging consumers. These proposals address a variety of issues that are important to resolve in arranging efficient provision of and payment for reactive power. Some of these proposals can be implemented in conjunction with the locational spot pricing framework.

Although the benefits (value) of reactive power might influence price, there are few articles that discuss these benefits. Sauer *et al* [2001, pp. 18-22] provides an example that shows how reactive power can increase real power transfer capabilities, and how this benefit falls as MVAr output rises. Hogan [1993, p. 179] refers to this benefit when he says "…limitations on transmission flows described as limits on transfer capability are… more often driven by contingency-induced voltage limits…" Dingley [2002, p. 18] notes "optimal power factor correction practices … reduce line losses." In principle, reactive power prices should reflect a balancing of benefits and costs; but in practice, the benefits are implicit in power system operating constraints (such as voltage constraints) or are ignored altogether.[3]

We concur with the remark made by Dingley [2002, p. 1]:

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[3] In principle, constraints should be set to reflect a balancing of the benefits and costs attributable to the constraints. For example, a requirement that certain voltages must fall within 5% of target levels implies that the benefits of keeping voltages within this band are at least as great as the associated costs.

> "The complexities of unbundling the pricing of reactive power are well appreciated in the literature, but the solutions offered are generally complex and are beyond the approaches adopted to date in even the most advanced market environments."

As this survey will show, the solutions that are most efficient in theory tend to be impractical to implement, while the solutions that are practical to implement tend to suffer important inefficiencies. Moreover, the reader should keep in mind the fact that most of the cited articles were published at a time when there was high optimism for market solutions, and relatively little concern for the market power problems that must inevitably plague some of the proposals.

### 2.1. Reactive Power Costs

Reactive power costs appear to constitute roughly 1% of power industry costs. Kirby and Hirst [1997, p. v] find that "embedded-cost tariffs average about $0.51/MWh, equivalent to $1.5 billion annually for the United States as a whole." Kirby and Hirst [1996, p. vi] indicate that this amounts to 1.2% of all generation and transmission costs. Similarly, Dingley [2002, p. 1] finds, for South Africa, "The national cost of reactive power is… about one percent of industry turnover, implying that imperfections in the cost-reflectivity of reactive power charges are swamped by even minor imperfections in the cost-reflectivity of other components of the total charge." New Zealand's Grid Security Committee Ancillary Service Working Group [2000b, p. 6] finds that the average cost of voltage support amounts to U.S. $0.27/MWh.

The literature divides reactive power into fixed and variable components, with nuances. See, for example, Barquin *et al* [1998, p. 545], da Silva *et al* [2001, p. 807], and Sancha *et al* [1997, p. 3]. Da Silva *et al* divide variable costs into explicit costs (e.g., out-of-pocket operation and maintenance costs) and implicit costs (e.g., opportunity costs of lost profits on real power due to producing reactive power instead).[4] Sancha *et al* divide variable costs into operation and maintenance costs and production costs. The division of costs into fixed and variable components is important because, as we shall see, it implies that prices that give efficient investment and dispatch incentives should be similarly divided into fixed (capacity) and variable (performance) components.

In this section we sequentially consider the characteristics of the various types of reactive power equipment, the estimation of the fixed costs of reactive power equipment, and the quantification of the variable costs of reactive power production. For an excellent elementary discussion of the economics and costs of reactive power, suitable for the non-engineer, the reader is directed to Berg [1983].

#### 2.1.1. Reactive Power Equipment

Alvarado *et al* [1996] say that the choice of reactive equipment depends upon the time-varying characteristics of load. Reactive power needs associated with slowly changing loads can be met

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[4] A generator's capability curve determines whether and to what extent that generator incurs an opportunity cost to provide reactive power. In almost all generators, provision of reactive power at maximum power output has no effect at all up to a point. Beyond that point, however, reactive power can become suddenly and discontinuously very expensive: to get one MVAr of reactive power, the generator might need to forego production of several MWs of real power.

with slowly changing or “static” reactive support equipment such as capacitors and reactors, while rapidly changing loads, such as arc furnaces, require rapid or “dynamic” reactive support equipment such as static VAr compensators (SVCs), synchronous condensers, and generators. The first two of these devices can rapidly supply or absorb VArs, while generators can change VAr output at a less rapid speed but still in a continuous manner. The costs of satisfying static reactive power demands are much lower than those of satisfying dynamic reactive power demands because the capital costs of static sources are much lower than those of dynamic sources.

Kirsch [1996, p. 7-25 *et seq*] echoes Alvarado *et al*’s remarks about static versus dynamic loads. He also states that the costs of reactive power depend upon whether demand is direct or indirect. *Direct consumption* of reactive power occurs at the customer site. It can therefore be served by equipment that is located close to the customer, and can be accurately metered at the consumer’s site. *Indirect consumption* of reactive power arises from the power flows throughout the power system that accompany a customer’s use of real power. These power flows lead to reactive power losses that require compensation by reactive power-producing equipment located throughout the power system. Indirect consumption can be quantified only though complex optimal power flow (OPF) analysis rather than through direct metering.

Kirby and Hirst [1997] provide the following table describing the characteristics of voltage control equipment:

**Table 1**
**Characteristics of Voltage Control Equipment, per Kirby and Hirst [1997, p. 13]**

| Equipment Type | Speed of Response | Ability to Support Voltage | Costs (in U.S. $) | | |
|---|---|---|---|---|---|
| | | | Capital (per kVAr) | Operating | Opportunity |
| Capacitor | Slow, stepped | Poor, drops with $V^2$ | $8-10 | Very low | No |
| STATCOM | Fast | Fair, drops with V | $50-55 | Moderate | No |
| Static VAr compensator | Fast | Poor, above its rated value it drops with $V^2$ | $45-50 | Moderate | No |
| Synchronous condenser | Fast | Excellent, additional short-term capacity | $30-35 | High | No |
| Distributed generation | Fast | Fair, drops with V | difficult to separate | High | Yes |
| Generator | Fast | Excellent, additional short-term capacity | difficult to separate | High | Yes |

Table 2 presents the similar table prepared by New Zealand’s Grid Security Committee Ancillary Service Working Group [2000b]. In this table, dollars are in U.S. dollars and “GO” refers to the grid operator. This table apparently ignores the variable costs of maintenance and wear-and-tear.

**Table 2**
**Costs of Voltage Control Equipment,**
**per Grid Security Committee Ancillary Service Working Group [2000b, p. 5]**

| Resource or Action | Approx. Fixed Cost | Approx. Variable cost |
|---|---|---|
| Fixed Capacitors | $2/kVAr/y | zero or low |
| Transformer tap changers | inc. cap. cost is very low | zero or low |
| Static VAr compensators (SVC) | $6/kVAr/y | zero |
| Generators' mandated reactive power capability | inc. cap. cost 1% of total generator cost | low |
| Generators in synchronous comp mode | $9/kVAr/y | moderate |
| Constrained on generators (by GO) | | potentially high |
| Committed generators | startup cost | reflected in nodal prices |
| Load shedding for voltage reasons | | value of lost load |

Tables 1 and 2 basically find that the faster and better devices are more expensive.

### 2.1.2. Fixed Costs

As implied by Tables 1 and 2, the fixed costs of reactive power equipment are straightforward for equipment that *only* manages reactive power, but are less straightforward for generators. The problem is that generators are built to provide both real and reactive power services, and the same piece of equipment within a generator may provide both services, sometimes simultaneously and sometimes not.

Consequently, several articles propose various methods for quantifying the portion of generation capital costs that should be attributed to reactive power. These methods are as follows:

a. *Incremental costs.* The fixed costs of reactive power are "the difference between the plant building cost with and without a reactive margin, and … the cost of the equipment needed to use that margin." Barquin *et al* [1998, p. 545]

$$CC_{kVAr}^{gen} \quad = \quad CC_{kVA}^{gen} - CC_{kW}^{gen}$$

where $CC_{kVAr}^{gen}$ is the generator's capital cost of providing reactive power, $CC_{kVA}^{gen}$ is the generator's total capital cost *including* reactive power capability, and $CC_{kW}^{gen}$ is the generator's total capital cost *excluding* reactive power capability.

b. *The costs of synchronous condensers* as a "valuation proxy." "[T]he capacity cost per kVAr between a typical synchronous compensator and a typical generator would be used as the reactive power capacity cost… [R]eactive power… would be valued on the basis of the avoided cost of building a new installation." Da Silva *et al* [2001, p. 809] Similarly, "Because reactive power produced by a generator is equivalent to that of a synchronous condenser, the costs of supplying reactive power by synchronous condensers can represent the equivalent costs of reactive power supply by generators." Hao and Papalexopoulos [1997, p. 99]

$$CC_{kVAr}^{gen} = \frac{CC_{kVAr}^{syncon} * CAP_{kVAr}^{gen}}{CAP_{kVAr}^{syncon}}$$

where $CC_{kVAr}^{syncon}$ is the synchronous condenser's capital cost, $CAP_{kVAr}^{gen}$ is the generator's reactive power capability, and $CAP_{kV}^{syncon}$ is the synchronous condenser's reactive power capability.

c. *Ratio of kVAr to kVA.* Reactive power capacity costs per kVAr equals capacity costs per kVA times kVAr capacity divided by kVA capacity. An adjustment may be needed "…to reflect more accurately the actual changes in plant capital costs associated with more lagging power factor operation…" Da Silva *et al* [2001, p. 809] Similarly, "For the embedded cost based methods, a portion of the generator and exciter costs… determined by the ratio of reactive power output to the total power, is allocated to the reactive power service." Hao and Papalexopoulos [1997, p. 99]

$$CC_{kVAr}^{gen} = \frac{CC_{kVA}^{gen} * CAP_{kVAr}^{gen}}{CAP_{kVA}^{gen}}$$

where $CAP_{kVA}^{gen}$ is the generator's apparent power capability.

d. *One minus the ratio of kW to kVA.* Reactive power capacity costs equal total capacity costs times one minus the ratio of the generator's kW rating to its kVA rating. Sancha *et al* [1997, p. 3]

$$CC_{kVAr}^{gen} = CC_{kVA}^{gen} * \left(1 - \frac{CAP_{kW}^{gen}}{CAP_{kVA}^{gen}}\right)$$

where $CAP_{kW}^{gen}$ is the generator's real power capability.

e. *Triangle method.* "The cost of the portion of the generators used to provide reactive and voltage support should include an allocated portion of the cost of the exciter and generator for each unit which produces VArs, as well as an allocated portion of the power consumed by the exciter and generator… [T]he kVAr portion is equal to the square root of the difference between the squares of kVA and kW. Therefore, only the reactive portion of the total exciter and generator investment in the units would be allocated to this service. To the allocated exciter and generator investment a production carrying charge net of O&M is applied to arrive at an annual carrying charge for the exciters and generators. The fixed O&M component should be calculated by multiplying the total fixed O&M for each unit by the ratio of the allocated exciter and generator investment to the total exciter and generator investment… [A]n allocated portion of the power consumed by the exciter and generator for each unit must be included in the charge for this service. The same allocator used to allocate the investment described above and energy and capacity costs of the units should be used to calculate the capacity consumption and energy consumption allocated to this service. The total of these components is then divided by the respective peaks… to develop the unit charges." Heintz [1996, pp. 4-5]

$$CC_{kVAr}^{gen} \quad = \quad CC_{kVA}^{gen} * \frac{\sqrt{\left(CAP_{kVA}^{gen}\right)^2 - \left(CAP_{kW}^{gen}\right)^2}}{CAP_{kVA}^{gen}}$$

f. *Cooperative game theory* that "allocates to each product at least the separable portion of the total cost for producing each product and at most the alternative costs for producing the individual product alone." Hao and Papalexopoulos [1997, p. 97]

$$CC_{kVA}^{gen} - CC_{kW}^{gen} \quad \leq \quad CC_{kVAr}^{gen} \quad \leq \quad \frac{CC_{kVAr}^{syncon} * CAP_{kVAr}^{gen}}{CAP_{kVAr}^{syncon}}$$

which implies that Method f should be bounded by the results of Methods a and b.

Method a tries to estimate reactive power costs directly from generator information, while method b tries to infer the value of generator reactor power services from the cost of other reactive power sources. Methods c through e are three arbitrary approaches for using relative real and reactive power capacities to infer their relative costs: it is impressive that three sets of authors each chose a different variation of the same arbitrary rule, without any recognition of the alternatives or any justification for why their variation might be best. Method f seems to be similar or identical to the Aumann-Shapley method for cost allocation described in Section 2.5, which gives it a patina of theory.

### 2.1.3. Variable Costs

The literature barely mentions the variable costs of reactive power equipment that *only* manages reactive power. Da Silva *et al* [2001, p. 808] report that the variable costs of shunt capacitors and reactors are limited to energy losses and to the depreciation that results from switching operations.

The literature is more concerned with the variable costs of reactive power from generators. Barquin *et al* [1998, p. 545] assert "The variable cost is mainly due to the active losses in the generator and in the step up transformer caused by the reactive power." Barquin *et al* also assert that only in "exceptional circumstances" will it be necessary to consider opportunity costs of active power production that is lost due to the need to produce reactive power.

Sauer *et al* [2001, pp. 26-28], by contrast, provide an example that shows how increases in a generator's reactive power output may require an accompanying reduction in that generator's real power output, and how this creates an opportunity cost for reactive power generation. They also show (pp. 23-26) how bilateral transactions need voltage support at locations throughout the power system, not merely at the points of power injection and withdrawal.

The variable costs of generation are central to the locational spot pricing framework described in the next section.

### 2.1.4. Assigning Costs to Individual Transactions

Huang and Zhang [2000] propose three methods for determining the costs of transmission transactions. First, they suggest evaluating "the incremental reactive losses of an individual transaction by comparing two power flow results before and after the trade. For sequential trades, this method runs a power flow or OPF program once for each additional deal. For simultaneous transactions, the above procedure will be repeated many times, which covers all potential trade ordering sequences. An average value over all reactive loss evaluation patterns is chosen to represent a specific reactive loss portion of each trade… [This] method is time-consuming for a large number of simultaneous trades, and may not provide justifiable incentives to the trades that mitigate line loading and reactance loss…"

Second, they describe how reactive power costs might be determined according to a "reactive flow tracing method" that "traces reactive flows from a specific generation bus to sinking buses in the network, and finds contributions of generators to reactive loads… However, in the presence of large shunt terms, reactive power flows… are complicated, which results in inefficiency – even inability – of tracing reactive power flows."

Third, they propose that generators' voltage control costs be "distributed to the actual reactive loss incurred by each load. Though both real flows and reactive flows in the interconnected network are traceable… it seems impractical to assess specific contribution of each generator on picking up reactive losses incurred by individual load." They therefore assign to each load a share of total voltage control costs, where the share is that load's fraction of total reactance losses. In essence, they assume that each kVAr of reactance loss has an equal cost regardless of its location (and perhaps time).

## 2.2. The Locational Spot Pricing Framework

A major strand of the theoretical literature on reactive power pricing proposes that reactive power prices be set on a locational (nodal) spot basis. The pricing of reactive power would thus be virtually identical to the way that New York and the Pennsylvania—New Jersey—Maryland Interconnection (PJM) presently price *real* power on a locational hourly basis. Such an approach has some important theoretical strengths, as well as important practical limitations.

The basic idea of locational pricing is that reactive power is worth more in some locations (perhaps load centers) than in other locations. This implies that the cost of providing reactive power to dense load centers may be relatively high, and that the value of reactive power provided by generators who are far from low centers may be relatively low. Locational spot prices for reactive power could provide incentives for loads to consume reactive power efficiently and for generators to produce reactive power efficiently.

The first three subsections respectively discuss articles that propose the basic framework, explain why the framework is important, and add various features to that framework. The fourth subsection cites articles that discuss implementation issues. The fifth subsection cites articles that discuss other problems with the framework.

### 2.2.1. Description of the Framework

Baughman and Siddiqi [1991], Baughman *et al* [1997], Dandachi *et al* [1995], Hogan [1993], Schweppe *et al* [1987], and Siddiqi and Baughman [1994] describe how static demands for reactive power should be priced given a fixed stock of capital equipment. They use OPF programs to estimate optimal real and reactive power prices that vary by location and time. The OPF programs find these prices by minimizing power system costs subject to constraints on generator outputs, transmission flows, and bus voltages. For any location and time, the optimal reactive power price equals the change in power system costs that accompanies a change in reactive power demand at that location and time. Because reactive power is difficult to transport among locations, optimal reactive power prices (and their underlying marginal costs) can vary widely over locations.

The resulting reactive power prices can be divided into components. For the optimal price at a given bus location, Baughman *et al* [1997, pp. 497-499] find that the two main components are:

- the marginal cost of generating any power necessary to serve an increment of reactive power load at the bus; plus
- the expected increase in outage costs (reduction in system reliability) caused by an increment of reactive power load at the bus.

They also find several minor terms that reflect how an increment of reactive power load at the bus affects the deviation between actual and scheduled tie-line flows, curtailment premia, congestion charges, voltage quality, reactive power security, and emissions.

El-Keib and Ma [1997, p. 561] find that optimal reactive power prices have three components. The first two components – the effect of an increment of reactive power load on network active power losses and on system voltage security – are essentially identical to the two bulleted components listed above. The third component – the effect of an increment of reactive power load on scarce reactive power generation capacity – is more a mathematical nuance than a real component of price.

### 2.2.2. Importance of the Framework

The literature asserts that the framework is important for two basic reasons. First, it provides the *only* means of getting accurate locational prices for real power as well as reactive power. Second, it provides a basis for pricing the supply and demand of reactive power.

Baughman and Siddiqi [1991] say that "real-time pricing of reactive power should develop simultaneously with that of active power…" (p. 23) Li and David [1994, p. 1269] say "DC load-flows are inappropriate for determining wheeling rates because they ignore the effects of reactive power flow; … the potential error of ignoring reactive power in wheeling studies increases with the magnitude of the wheel and if the power factor of the wheel is bad." Hogan [1993] provides a slew of reasons why locational spot pricing of *reactive* power should accompany locational spot pricing of *real* power and why AC modeling is necessary:

- "In the presence of voltage constraints, the DC-Load model is insufficient [for determining efficient locational prices], and the full AC-Model is required to determine both real and reactive power spot prices." (p. 171)

- "In the presence of voltage constraints the reactive power marginal cost can be of the same order of magnitude as the real power cost." (p. 182)
- "[F]or a complicated network the DC-load model may provide little or no information about the marginal costs of real power at different locations in the presence of congestion arising from voltage constraints at buses." (p. 188)
- The practice of pricing "…in terms of MVA equivalent… attempts to ignore or hide the corresponding reactive power marginal costs… [and depends] on an assumption that there is a simple relationship between real and reactive spot prices, or that reactive marginal costs are negligible compared to the costs of metering and collection… [T]here is no correlation between the real and reactive prices at a bus." (pp. 189-91).
- "[I]f spot pricing to account for losses matters at all, then reactive power prices can have the same marginal significance as real power prices." (p. 191)
- "…one reason often cited for neglecting reactive power is that actual dispatch typically results in relative[ly] little reactive power load… [A]t the margin the implication is not that reactive power is negligible but rather that it is extremely important. Frequently the entire system is dispatched, and substantial real power out-of-merit costs incurred, in order to keep the net reactive volumes small." (p. 195)

### 2.2.3. Extensions of the Framework

Several authors have suggested modifications and extensions of the basic framework.

*Decoupling the Optimum Power Flow (OPF) Problem*

El-Keib and Ma [1997] decouple (separate) the OPF problem into two parts: a real power optimization that minimizes costs subject to power balance, line flow, and generator operating limit constraints; and a reactive power optimization that minimizes network losses subject to constraints on reactive power output at each bus, voltages at each bus, and tap ratio limits on transformers. The authors assert that this decoupling "provides the necessary flexibility for real-time applications, as separating P [real power] and Q [reactive power] controls separately has been an accepted practice. Also, this approach avoids the coupled OPF formulation which often produces solutions that are impractical to implement since many voltage/reactive variables are adjusted to gain a very negligible improvement in production cost." (p. 563)

In a discussion accompanying the El-Keib and Ma article, V.C. Ramesh questions the value of decoupling the OPF problem into two parts, saying "There are other ways to include network losses while retaining the coupled OPF formulation… Hence, it is possible to obtain the short-run marginal costs (SRMCs) of real and reactive power production simultaneously instead of obtaining them independently using a decoupled formulation." (p. 565) El-Keib and Ma reply that "the decoupled formulation… results in more stable solutions… [while] the coupled OPF often results in solutions that are not practical to implement… since many Volt/Var variables are adjusted to gain a very negligible improvement in production cost." (p. 565)

Paucar and Rider [2001] also decouple the problem because of their belief that it gives more stable solutions. Their decoupled problems are different than El-Keib and Ma, however. Their active power subproblem minimizes total operating costs of providing active power, while the reactive power subproblem minimizes the total operating costs of providing reactive power plus a specified amount of active power at the slack generator.

*Inclusion of Capital Costs*

Dai *et al* [2000] add the capital cost of capacitors to the OPF determination of prices, and claim that this amendment to the OPF problem improves estimated reactive power prices. Similarly, Hao and Papalexopoulos [1997, p. 96] note that the framework considers only variable costs of reactive power production, and assert that "the capital costs incurred as part of the reactive power service should be used in the reactive power price calculation."

Chattopadhay *et al* [1995] advocate nodal hourly pricing of reactive power to pay for generators' "operating costs incurred to supply the additional reactive power," plus fixed cost payments for capacitors.

We believe that the direct inclusion of capital costs into the OPF framework would be nonsensical, as the framework is a dispatch model that should consider only variable costs. Instead, capital costs should be recovered and priced through a separate fixed (capacity) charge that would allow dispatch to be efficient.

*Price-Sensitive Demands*

Weber *et al* [1998] add price-sensitive demands, for both real and reactive power, to the OPF model formulation for determining nodal spot prices.

2.2.4. Problems with Implementing the Framework

A few authors who are favorably inclined toward the locational spot pricing framework nonetheless find that it has serious implementation problems.

Baughman *et al* [1997, p. 501] say "The software, hardware, manpower, and computational requirements to calculate the advanced real-time prices in strict accordance with the theory set forth in this paper are formidable. Just solving large optimal power flows requires state-of-the-art hardware and software. Solving for the advanced real-time prices set forth in this paper would require solving a stochastic optimal control problem in which the power flow constraints are embedded. With today's computer technology, this problem can only be solved after making simplifications to the problem specification."

Zobian and Ilic [1997, p. 2] state "The use of OPF in real-time operation is currently infeasible, mainly due [to] the computational complexity and massive amount of information and controls required to operate the system efficiently. Instead, power pools now utilize constrained economic dispatch (CED) software for real-time operation and control. The CED is a simpler software that … ignores reactive power… [W]e propose to use the OPF for scheduled transactions on an hourly basis, while another real-time software takes care of accounting for the costs incurred in the short time scale between successive OPF runs."

Dandachi *et al* [1995, pp. 5-6] state that the OPF package then used by the National Grid Company (England and Wales) was not able to accommodate a transmission-constrained economic dispatch of reactive power. The basic problems are that manual changes to the computations are required to make the OPF work, and that the OPF model does not consider uncertainty:

> "[C]ompared with a SC-OPF [security-constrained optimum power flow] dispatch objective that enforces operating limits with minimum control action (MCA), the new MVAr cost objective seems to produce much better overall Var usage and distribution. However, this is achieved by moving most of the system's designated controls… Clearly, it is not possible to perform system-wide redispatch of quantities like transformer taps and shunt capacitors at very frequent time intervals. Therefore, a practical implementation approach is to perform the new MVAr cost minimizing calculation only at key points during the system load cycle to establish Var dispatch schedules…
>
> "…MVAr cost minimization tends to drive the power system against some of its voltage and generator Var limits. Given that the OPF model does not represent data uncertainty, more margin is needed for practical operation/control purposes. Moreover, with no contingency constraints, the SC-OPF solution can make post-contingency conditions worse… A promising method … is to add pre-contingency MVAr reserve constraints at all stations… The optimum amount of reserve to specify is a subject for further work…
>
> "When any outage case does not converge, the approach at NGC is to use engineering experience to switch in the additional compensation equipment needed to make the case converge."

Similarly, the National Electricity Market Management Company (NEMMCO) [1999, p. 17], which is the organization that manages Australia's power system, found serious problems with implementing nodal spot pricing of reactive power:

> "In its final implementation this envisages a full nodal active/reactive power dispatch optimisation in order to maximise the value of power (active/reactive) traded taking into account the pre and post contingency time frame. The development of such a process will require considerable research and development effort by NEMMCO.
>
> "The current SPD linear programming technology is unsuitable for the light on the hill recommendation for NCAS. At this stage, commercial software to do this optimisation is unavailable and is unlikely to be available for another 5 years. One issue for NEMMCO is whether it should fund research and development into this technology, and whether such funding is justified for the expected improvement in market efficiency.
>
> "The recommendation to use nodal pricing for reactive power is far reaching and has not been implemented elsewhere within a market structure, to NEMMCO's knowledge."

### 2.2.5. Other Criticisms of the Framework

Locational spot pricing of reactive power has been criticized for some other reasons as well.

*Unimportance of reactive power pricing.* Taking strong exception to most of the analysis of Hogan [1993], Kahn and Baldick [1994] say "in his simplest example the price on this [voltage] constraint results from an uneconomic and artificial characterization of the problem, namely an inefficient and unnecessarily constrained dispatch. By eliminating this characterization, the price of reactive power falls to a very modest level…"

*Manipulation of reactive power markets.* Alvarado *et al* [1996] and Kahn and Baldick [1994] both express the concern that locational reactive power markets can be subject to manipulation. Alvarado *et al* say that this occurs "because the high cost or impossibility of transporting reactive power over long distances makes reactive power markets geographically small…" Kahn and Baldick suggest "either some kind of monitoring and audit function to detect potential abuses, or alternatively, institutional restructuring to eliminate conflicts of interest." (p. 191)

*Price volatility.* Hao and Papalexopoulos [1997, p. 96] are concerned about the "'enormous' volatility of the locational node prices for reactive power…"

*Failure to price dynamic demands.* In addition to the concerns expressed in the literature, we note that the locational spot pricing approach fails to price dynamic demands. Because they are far more costly than static demands, they are more important to price right.

## 2.3. Other Proposals for Pricing Reactive Supply

Many authors propose other pricing methods, some of which can be implemented in conjunction with the locational spot pricing framework. We divide the discussion of these other methods into three areas: proposals that have separate prices for different categories of cost or resources; proposals for long-term supply arrangements; and proposals for setting penalties for failure to supply reactive power as promised or required.

### 2.3.1. Price Components

Da Silva *et al* [2001, p. 810], Gil *et al* [2000, pp. 484-485], and Sancha *et al* [1997, p. 5-6] propose that there be markets in reactive capacity and reactive energy. The basic rationale is that reactive power costs have both capital (capacity) and production (energy) components, and that locational spot prices can be volatile. Sancha *et al* note that "[W]ith only a production term… [it] will be very difficult for generators to predict their revenue and prepare their bids." With only a capacity term, generators might be reluctant to incur costs in real-time.

Under the proposal of Sancha *et al*, system operators would accept the bids that meet reactive power needs at minimum cost. Bids would differ by resource type, as follows:

**Table 3**
**Bids by Resource Type, per Sancha *et al* [1997, p. 4]**

| Resource Type | Capacity Bids | Production Bids |
|---|---|---|
| Reactances & Capacitors | • MVAr offered<br>• price per hour available<br>• hours available per year | |
| SVCs | • MVAr offered<br>• price per hour available<br>• hours available per year | • MVArh price curve by MVAr output level |
| Generators | • MVAr offered<br>• price per hour available | • MVArh price curve by MVAr output level |

Sancha *et al* would pay reactances and capacitors according to their availability and capacity bidding price. Unavailability declared in advance would result in no payment, while failure to declare unavailability would be penalized. Generators would be paid according to how well voltage control is performed, with penalties assessed according to "mean voltage deviation." "Zero voltage deviation can be easily achieved with automatic voltage controllers…" (p. 5)

Similar to the Sancha *et al* scheme shown in Table 3, Kirsch [1996, p. 7-25 *et seq*] proposes separate recovery of reactive power costs according to resource type. Local reactive power devices (i.e., to compensate for poor power factors of individual customers) can be provided competitively, so that their prices can be set through normal competitive processes. Because system reactive power devices (i.e., non-generation equipment not attributable to individual customers) are inherently a part of the transmission firm's monopoly, their costs would be recovered through transmission rates. Reactive power provided by generators would be acquired on a long-term basis, partly because generators' decisions to provide reactive power service are basically investment decisions and partly to mitigate market power.

Da Silva *et al* [2001, 807] imply that the production component of the reactive power compensation should include opportunity costs (if any) of foregone real power sales.

### 2.3.2. Long-Term Supply Arrangements

To mitigate the potential exercise of market power, Alvarado *et al* [1996], Gil *et al* [2000, p. 484], Hao and Papalexopoulos [1997, p. 101], Kirsch [1996, p. 7-25 *et seq*], Kirsch and Singh [1995], and Sancha *et al* [1997] recommend that reactive power from competitive resources be procured by system operators through long-term contracts. As Sancha *et al* explain, in three years time, "reactive power resources such as shunt capacitors, reactances or SVCs could be installed in any place in the network and nobody could obtain excessive benefits of any particular location with a high power market associated with it if the reactive power market were to begin immediately." (p. 3)

Gil *et al* [2000, pp. 484-485] propose that reactive energy and reactive capacity markets be based on resources' long-term bids, including information on each bidder's losses curve. Winning bidders would have a long-term obligation for voltage regulation, and would receive a capacity payment. For the reactive energy market, the system operator would price losses at the hourly spot price for active energy, would dispatch the system to minimize costs including reactive losses, and would price reactive supplies and demands at the losses minimization spot price. Reactive energy prices would vary by bus.

The foregoing auction and pricing schemes tend to be short on some critical details. The proposals do not clearly specify the rights that the system operator obtains by accepting a long-term capacity offer, nor how many years that the system operator might be obligated to pay for the winning capacity. Because most reactive power costs are investment costs, once a capacity offer is accepted, and that capacity is built, it may be available for decades: how, if at all, will the capacity terms recognize this fixed availability? The proposals are also unclear about whether the long-term auction winners receive their own bid price or a market-clearing price based on the highest winning bid. Gil *et al* [2000, p. 486] further confuse the issue by providing the mathematics for a scheme under which the payments for capacity will vary by bus according to the spot value of reactive power produced at each bus. This second scheme masks price volatility without really mitigating it, and bears no obvious relationship to their long-term capacity bid proposal.

Huang and Zhang [2000] oppose long-term pricing of reactive power. They say that "Long-run pricing is solely based upon nominal capacity of loads, not the actual operating point. It may unfairly allocate reactive costs to users." They instead propose to encourage investment in reactive power equipment by dividing "reactive support of generators into two functions: reactive power delivery and voltage control…" and by devising "a payment framework to allocate reactive support cost of generators to the bidding loads and bilateral trades on the real-time operating point basis. In our method, the reactive sensitivity matrix derived from the fast decoupled power flow algorithm is used to determine reactive delivery allocation pattern; meanwhile, efficient reactive loss formulae are developed to charge voltage control costs of generators."

Alvarado *et al* [2000, p. 29] mention the significance of reactive reserves. "It is often necessary to have capability for reactive power in excess of amounts actually used for purposes of operability under contingency conditions. Thus, compensation is required not only for reactive power actually used, but also for reactive power required in reserve." Flatabo *et al* [1985, 1986] establish and demonstrate criteria that may be used to establish the amount of reactive reserves required by a system.

### 2.3.3. Penalties for Non-Performance

Sancha *et al* also propose that "Those generators… whose reactive power offers were not accepted should maintain a power factor between some defined limits… and could be penalized if they violate them." (p. 3) This limitation on generators failing to win bids is unnecessary, as all resources should be welcome to provide reactive power on short notice. The system operator could then have resources lined up well in advance, for which it pays capital costs and variable costs, plus resources lined up on short notice, for which it pays only variable costs.

Hao and Papalexopoulos [1997, p. 99] propose no payments to resources within pre-specified bands, with payments made for dispatch outside of the bands. Penalties would be levied for failure to follow dispatch.

### 2.4. Proposals for Allocating Reactive Power Costs

This section begins with a discussion of articles that support charges for direct reactive power consumption, a method widely used in practice.[5] The subsequent subsections respectively address the problem of reconciling efficient marginal cost prices with cost recovery requirements, the desirability of multiple reactive power charges, and self-provision of reactive power.

#### 2.4.1. Charging for Direct Reactive Power Consumption

Several authors comment on reactive power charges that are based upon consumers' power factors. Berg [1983] highlights the irrationality of cost recovery based upon power factors, partly because of the lack of a causal relationship between power factors and reactive power costs, and partly because of the wildly inconsistent ways that different utilities use power factors to develop reactive power charges. Baughman and Siddiqi [1991, p. 28] find that "Reactive power pricing based on power factor penalties is unable to provide accurate price signals to customers under voltage constraints… [P]ower factor penalties are unable to give accurate price signals to customers, while real-time prices provide such signals." Baughman *et al* [1997, p. 499] say "power factor penalties are unable to provide appropriate incentives to customers and/or suppliers to alter their reactive power usage/supply patterns when voltage limits are reached, the precise times when the price of reactive power is most important to regulating system voltage. Real-time [locational] reactive power pricing does provide appropriate incentives."

Fink [1996, p. 22] asserts "reactive load requirements should be the responsibility of the end user… so that only active (unity power factor) load is supplied by the network… [C]ustomer reactive requirements should either be supplied by equipment purchased by the customer himself (power factor correction), or provided locally by his distribution provider."

Da Silva *et al* [2001, p. 811] say "Charging D[istribution] companies on the basis of their metered consumption of reactive energy offers significant attractions in terms of sending accurate signals to those companies which need to invest in power factor correction most urgently… This Reactive Charge should ideally be derived by examining the proportion of the reactive energy which is required on the system which is specifically associated with *demand*, rather than inherent transmission (T) network requirements. This can be done analytically by evaluating in broad terms the approximate proportion of the reactive requirements of the system which is associated with reactive power losses in transmission lines, and subtracting this from the total system reactive requirement. The balance may be categorized as that reactive energy which is required to supply the reactive demands associated with D systems and T connected customers."

Da Silva *et al* also say "it would be preferable to charge for lagging reactive consumption across the full range of power factors from unity downwards, and to leave the consumers/companies to decide on the economic level of compensation to install in their systems. This is likely to prove less arbitrary than prescribing an 'optimum' power factor through the adoption of a 'dead-band' around unity power factor within which no charges would be payable." (p. 811)

[5] See Section 3.5 for a discussion of practice.

### 2.4.2. Reconciling Marginal Costs With Cost Recovery

The locational spot price framework described in Section 2.2 provides reactive power prices (or marginal costs) that will generally under-recover the full capital and variable costs of providing reactive power. The charges for direct reactive power consumption described in Section 2.4.1 will also recover only a part of the full costs of reactive power. If locational prices and charges for direct consumption serve as the basis for allocating reactive power costs, it would therefore be necessary to develop additional mechanisms for full cost recovery.

Alvarado *et al* [1996] say that the retail prices for reactive power "should primarily reflect the marginal capital costs of reactive power service, and they should differ according to the dynamic nature of the reactive power loads. *Marginal costs*, rather than embedded costs, are the appropriate basis for pricing because marginal cost prices are efficient and because a competitive market in reactive power services will tend to drive prices toward marginal cost. *Capital costs* are appropriate for reactive power pricing because these are the major reactive power costs and because, in a future competitive market, reactive power will be traded primarily under long-term contracts that reflect the capital costs of incremental investments in reactive power service. Because the capital costs of static and dynamic sources are so different from one another, there should be different prices for static and dynamic reactive power loads. *Price differentiation among static and dynamic reactive power loads* is appropriate because of the extremely different costs of serving these two types of loads." "Dynamic reactive power loads" include the rapidly changing reactive needs caused by rapidly changing active power loads.

Alvarado *et al* [2000] state that, "to promote economic efficiency in resource utilization *cost allocation based on marginal cost is most desirable* because it is compatible with a competitive economic environment." (p. 18) They suggest two means for reconciling marginal costs with cost recovery requirements. First, they suggest that marginal costs can be uniformly scaled up or down so that marginal cost-based revenues exactly equal total reactive power costs. Second, they emphasize the advantages of Aumann-Shapley charges as a means of reconciling marginal costs with revenues. "[T]he Aumann-Shapley unit charge … can be interpreted as the mean marginal cost … [as] loads increase uniformly from zero to their actual value…" (p. 28) "Because it is based on marginal costs, Aumann-Shapley has the property of inducing economic efficiency. In addition, it is generally considered 'fair' in the sense that it eliminates 'order of entry' as a consideration. Another important property of Aumann-Shapley allocation is that it has the property of recovering cost… [I]t is the unique cost allocation method that recovers the original costs (revenue reconciliation), is additive, weakly aggregation invariant and monotonic." (p. 25)

Vieira *et al* [1997] propose an allocation scheme that appears to be identical to Aumann-Shapely. They say that this scheme resolves two problems with marginal cost pricing of reactive power. First, they assert that marginal cost pricing will result in overcollection of reactive power costs because of decreasing returns. Second, they note that the allocation of reactive power costs among consumers can depend upon the order in which consumers are charged for reactive power service. Their allocation scheme assures that reactive power costs are exactly recovered; and it does not depend upon the order in which consumers are assumed to receive reactive power service.[6]

Gil *et al* [2000, p. 487] propose that full cost recovery be achieved through two charges for reactive power. First, distribution utilities and large consumers would pay nodal losses reactive spot prices for their reactive energy consumption. Second, any reactive power supply costs not recovered through the first charge would be recovered through an uplift on all active energy traded through the pool market.

Similarly, Kirsch [1996, p. 7-25 *et seq*] suggests that reactive power charges be divided into three parts: charges for *local reactive power devices* that are set by the market and are paid by the customer who benefits from the device; charges for *system reactive power service devices* that are set by the same rules as apply to the recovery of transmission revenue requirements, or that vary by time of use, zone, and dynamic versus static demands; and charges for *generation reactive power services* that are set by the same methods just described for system reactive power service devices.

### 2.4.3. Self-Provision of Reactive Power

Hao and Papalexopoulos [1997] support self-provision of reactive power service. "A transmission customer should have choices for supplying portions (or the entire amount) of the generation-related reactive power needed for supporting its transactions, to the extent that it is capable of doing so. However, it is highly impractical for transmission customers to supply reactive power along transmission paths. To overcome this problem, the development of the local reactive power market should be encouraged… [A] zonal based charge can be developed. Of course, if the transmission customer elects to self-provide reactive power, the service must be coordinated with the transmission provider." (p. 100) They go on to say that "reactive power capacity across different zones can also be traded… A zone multiplier… can be used to adjust the value of the reactive power capacity in different zones." We believe that this faith in markets and in self-provision of reactive power is unrealistic because the physical properties of reactive power – particularly transport difficulty – cannot allow short-term competition to flourish in reactive power markets except under extraordinary conditions.

## 3. SURVEY OF OTHER JURISDICTIONS' TREATMENT OF REACTIVE POWER

In this section, we summarize the reactive power market design and pricing policies of several power systems in which generation ownership has been separated from system control. We focus on the markets of New Zealand, the U.K. (England and Wales), and five U.S. Independent System Operators (ISOs): California, New England, New York, PJM, and Texas (ERCOT). For additional breadth, we also present some of the findings of two published surveys.

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[6] Aumann-Shapley pricing assumes that each resource providing reactive power to the system does so in an infinitesimally incremental manner, and that the order of "entry" among the providers is randomized to all possible entry orders. Alvarado *et al* [2002] and Vieira *et al* [1997] show that, in the limit, the process of randomizing entry of system users amounts to a simple integral that, when evaluated, leads every system user to pay a reactive power price that mimics marginal cost-based pricing while assuring full cost recovery.

The discussion is divided in five parts. The first two parts look at how reactive power service is defined and how system operators determine system reactive power needs. The third part describes the reactive power capability requirements that generators are expected to meet, while the fourth part explains how generators are paid for the reactive power service that they provide. The final part discusses the various ways that reactive power costs are recovered from customers.

### 3.1. Definition of Reactive Power Service

Although there is no standard definition of unbundled "reactive power service," there does seem to be a common understanding of what it means.

New Zealand defines the service as "the dispatch of reactive power and other support resources with the objective of managing voltage within the normal limits set out in the Co-ordination Policy."[7] Although New Zealand recognizes that voltage control can be provided by a wide variety of resources, the only resources that receive payment for voltage support ancillary services are certain capacitors owned by the transmission firm, static VAr compensators, generators in synchronous comp mode, and generators that are constrained-on to provide voltage support.

The U.S. Federal Energy Regulatory Commission [1996, pp. 208-211] requires all utilities under its jurisdiction to provide an ancillary service called "Reactive Supply and Voltage Control from Generation Sources." It explicitly excludes from this ancillary service the reactive power and voltage control services that are provided by transmission facilities such as capacitors, and includes only those services that are provided by generators.

The California Independent System Operator [2000b, p. 55] defines reactive power control as action taken to maintain acceptable voltage levels throughout the transmission system and to meet reactive capacity requirements at points of interconnection.

The New York ISO defines Voltage Support Service as including the ability to produce or absorb reactive power, and the ability to maintain a specific voltage level under both steady-state and post-contingency operating conditions, subject to the resource's capability limitations.

PJM divides generator reactive power products into two distinct types: "reactive power capability at rated generator output and reactive power provided at reduced generator output."[8]

The Electric Reliability Council of Texas (ERCOT) [2003, p. 5], which is not subject to FERC jurisdiction, defines voltage support from two different perspectives. First, this service is the provision, by Qualified Scheduling Entities (QSE) to ERCOT, of a generation resource whose power factor and output voltage level can be scheduled by ERCOT to maintain transmission voltages within acceptable limits. Second, this service is the provision, by ERCOT to the QSEs, of the coordinated scheduling by ERCOT of voltage profiles to maintain transmission voltages throughout the system.

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[7] Grid Security Committee Ancillary Service Working Group [2000b, pp. 16-17].

[8] PJM Interconnection Market Monitoring Unit [2000, pp. 29-31].

### 3.2. Determination of System Reactive Power Needs and Dispatch

System operators use power flow analyses to determine reactive power needs. In New Zealand, such analysis is not integrated with its real power dispatch, as its dispatch model provides only a DC approximation of losses and does not schedule voltage. In California, the ISO conducts power flow studies to determine the hourly quantities and locations at which voltage support is required to maintain voltage levels and reactive margins within guidelines established by the North American Electric Reliability Council (NERC) and Western Electricity Coordinating Council (WECC). In New England, New York, and PJM, the amount of service that is required to support a given transaction is determined according to the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region. In Texas, ERCOT conducts studies to determine target voltage profiles for all generation busses, though it may temporarily modify its voltage requirements based on current system conditions.

Table 4 lists the various actions that are taken to manage voltages in New Zealand. The actions that Transpower (the transmission company) takes to manage voltage include: 1) altering the operation of Transpower's own plant (such as switching in capacitor banks); 2) varying generation schedules so that they provide voltage support even when they might not otherwise be dispatched according to market; 3) directing operational settings on the plant of other parties (such as varying generator excitation); and 4) purchasing ancillary services (such as output from synchronous condensers). The first two types of action are the most important. In addition to "constraining-on" specific generators, the Grid Operator can impose "group constraints" into the market dispatch model to maintain voltage quality in particular regions.

**Table 4**
**Voltage Dispatch in New Zealand,**
**per Grid Security Committee Ancillary Service Working Group [2000b, p. 5]**

| Resource or Action | Supplier | Control |
|---|---|---|
| Fixed Capacitors | End-use customers | Switched in with load |
| Fixed Capacitors | Transpower | GO directs switching |
| Capacitors to meet mandated power factor requirement | Distributor | Switchable but slow response which drops with $V^2$ |
| Transformer tap changers | Transpower & distributors | Automatic (new) or manual (old) |
| Static VAr compensators (SVC) | Transpower (asset owner) | GO schedules; fast response but drops with $V^2$ |
| Generators' mandated reactive power capability | Generators | GO directs control settings |
| Generators in synchronous comp mode | Generators | GO directs control settings |
| Constrained on generators (by GO) | Generators | GO instruction |
| Committed generators | Generators | SPD schedules |
| Load shedding for voltage reasons | End users | GO directs |

In California, the ISO issues daily voltage schedules. Generators that have contractual arrangements with the ISO must comply with the power factor requirements set forth in their contracts, while those that do not must adhere to the power factor requirements applicable under the FERC tariff of the transmission owner to whom they are connected. Subject to locational requirements, the ISO chooses the least costly generators from a merit order stack to produce additional voltage support in each location where voltage support is needed.[9]

In New York, the ISO and the transmission owners are jointly responsible for scheduling reactive power service. The ISO coordinates voltages throughout the control area, while transmission owners are responsible for the local control of the reactive power resources that are connected to their networks.

In PJM, the Transmission Provider maintains scheduling oversight to ensure that all sources of reactive power are treated in an equitable and not unduly discriminatory manner. The Transmission Provider may change schedules as necessary to maintain system reliability. Local

[9] California Independent System Operator [2000a, pp. 38-39]

control center operators may also direct changes to generators' voltage schedules or reactive output. Control systems on generators are supposed to react automatically to changing system conditions and to increase or decrease reactive power output as needed to maintain local voltages.[10]

Texas' reactive power dispatch is unusual in that it attempts to minimize the dependence on generation-supplied reactive power. This minimization reflects Texas' philosophy that ERCOT should have the smallest possible role in Texas' markets, and should therefore instruct generator dispatch as little as possible. ERCOT does determine voltage support needs by location and posts all voltage profiles on its Market Information System, thus letting QSEs know the desired voltages at their points of generation interconnection. QSEs are required to respond to changes in these voltage profiles. ERCOT deploys static reactive power resources so that QSEs can maintain dynamic reactive reserves that are adequate to meet ERCOT System requirements.

### 3.3. Voltage Control Capability Requirements for Generators

All markets have some rules that indicate the minimum range of power factors that generators must provide as a condition of interconnection or market participation, and how well generators are expected to follow the system operator's reactive power dispatch instructions. Table 5 summarizes the minimum range of power factor requirements for several regions.

**Table 5**
**Power Factor Requirements for Generators**

| System | Uncompensated | |
|---|---|---|
| | Lagging | Leading |
| New Zealand | 0.87 | |
| U.K. – England and Wales | 0.85 | 0.95 |
| U.S. – California | 0.90 | 0.95 |
| U.S. – PJM | 0.90 | 0.95 |
| U.S. – Texas | 0.95 | 0.95 |

In New Zealand, Transpower, which owns and operates New Zealand's high-voltage electricity transmission grid, requires generators to provide reactive power capability and distributors to meet power factor limits under its connection contracts. These mandated requirements are often sufficient to ensure voltage standards are met, particularly where load and generation are balanced and transmission lines are lightly loaded. Generators are not compensated for meeting these requirements.

In the U.K. (England and Wales), the Grid Code connection conditions specify that all generators must be capable of supplying their rated power output at any point between the limits 0.85 power factor lagging and 0.95 power factor leading at the generator terminals. Additional services

[10] PJM Interconnection [2000, pp. 29-31].

above the mandatory conditions include Commercial Services such as synchronous compensation and extended power factor ability.[11]

In California, generators are required to provide reactive power by operating within a power factor range of 0.90 lag and 0.95 lead. Generators that are producing real energy are required, upon the ISO's request, to provide reactive energy output outside their standard obligation range, for which they receive additional compensation. All loads and distribution companies directly connected to the ISO-controlled grid must maintain reactive flow at grid interface points within a power factor band of 0.97 lagging to 0.99 leading.[12] Loads are not compensated for maintaining their power factor within the bandwidth. Power factors for both generators and loads are measured at their respective interconnection points with the ISO-controlled grid. The ISO levies penalties against generators, loads, and distribution companies who do not comply with the power factor requirements.

In New England, generators must be able to deliver or absorb reactive power with a power factor that is consistent with the interconnecting Transmission Provider's requirements, and must operate with automatic voltage regulators (AVRs) unless otherwise directed by the Transmission Provider. If a generator does not have sufficient reactive power capacity or fails to dispatch that capacity as directed by the system operator, the Transmission Provider may install the needed reactive compensation equipment at the generator's expense. Transmission customers must maintain overall load power factors and reactive power supply within predefined regions in accordance with standards set by the system operator. If a transmission customer lacks sufficient capability for this purpose, the Transmission Provider may install the needed reactive compensation equipment at the customer's expense.[13]

In New York, the ISO directs the generators to operate within their tested reactive capability limits.[14]

In PJM, generators must be built to maintain a composite power delivery at continuous rated power output at the generator's terminals at a power factor of at least 0.95 leading to 0.90 lagging. The Transmission Provider may allow small generation resources to meet lower standards. Generators must follow the Transmission Providers instructions to produce reactive power within the generators' design limitations. AVRs should be in service at all times while the generator is synchronized with the grid, except when the AVR is out of service or PJM directs otherwise.[15]

In Texas, generators must be capable of providing reactive power over at least the range of power factors of 0.95 leading or lagging, measured at the unit main transformer high voltage terminals. This capability must be maintained at all times the plant is on-line. There is no compensation for reactive power service within this range. Some generators – namely those that are qualified renewable generators and or were in operation prior to September 1, 1999 – are

[11] Office of Gas and Electricity Markets [2000, p 126].

[12] California Independent System Operator [2000b, pp. 4-7].

[13] New England Power Pool [2002a, p.7].

[14] New York Independent System Operator [2000, pp. 14-16].

[15] PJM Interconnection [2001, p. 5], [2002, p. 138].

held to lower requirements based upon the quantity of reactive power that they can produce at rated real power capability.

ERCOT instructs generators to make adjustments for voltage support within the capacity limits provided by the QSE to ERCOT. Generators providing reactive power are not required to reduce real power output so they can provide additional reactive power.[16] If power system reliability is at risk, however, ERCOT may instruct generators to provide additional reactive power without compensation.

Texas generators must use AVRs except under emergency conditions or when directed to operate in manual mode by ERCOT. A generator's AVR must be available at least 98% of the time that the generators is providing reactive power. Any generator-controlled power system stabilizers will be kept in service whenever possible. Generators responding in less than two minutes from the time of issuance of reactive output requests shall be deemed satisfactory.

## 3.4. Pricing of Reactive Supply

There is no standard methodology by which system operators pay resources for reactive power. There seems to be a growing consensus that generators should be paid for their opportunity costs of producing reactive power instead of real power; though a few years ago, prior to significant restructuring occurring, Kirby and Hirst [1997, p. v] undertook a survey of U.S. utilities in which they found that "reactive power… opportunity costs are not currently compensated for in most regions [of the U.S.]." There is not much consensus about how reactive power capacity prices should be set.

The U.S. Federal Energy Regulatory Commission [2002, ¶283], in its proposed Standard Market Design, has asked whether generators that provide reactive power should be paid for alleviating voltage or stability constraints and for thereby increasing the transfer capability of the grid. In this same proceeding, FERC has also asked whether compensation for opportunity costs is warranted. "Should the generator be paid the higher of its opportunity costs or the market congestion value of the additional transfer capability created? How should locational market power concerns be addressed in these circumstances?" In the U.S., these issues are unresolved.

In this section, we review some of the methods by which several regions price reactive power supply.

### 3.4.1. New Zealand

New Zealand's need for voltage support beyond minimum requirements is almost entirely limited to the Auckland region. Transpower has a few long-term supply contracts with generators that allow such additional voltage support to be specifically requested under certain circumstances. The pricing of this additional supply depends upon the source, and for generators usually includes the opportunity cost of foregone real power sales. Transpower's payments under these contracts form part of the cost of purchasing voltage support ancillary services.[17]

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[16] Electric Reliability Council of Texas [2003, p. 42].

[17] Grid Security Committee Ancillary Service Working Group [2000a, pp.11-13].

The current annual cost for voltage support is approximately US $3.4 million.

### 3.4.2. U.K. – England and Wales

National Grid Company (NGC) typically procures ancillary services under bilateral contracts. The length of these contracts varies between one year and the lifetime of the asset. Remuneration for the service can either be cost- or value-based. Although cost-based remuneration was initially considered appropriate for mandatory services, progress has been made towards introducing competition and market-based mechanisms for procurement and value-based remuneration.

NGC holds two tender rounds each year to meet its reactive power requirements. NGC publicly provides information on the tender evaluation, including the number and type of tenders, details on the proportion of successful bids, and the aggregate payments and volumes. During the first year of reactive power tenders (April 1998 to March 1999), approximately 27% of total reactive power payments were under contract with the remaining 73% being made under the default arrangements. In the second year (April 1999 to March 2000), 102 tenders were received from centrally dispatched generators (67% of eligible generators) at 39 power stations owned by 11 firms. As a result 75 agreements were offered and 57 were signed, representing 11 generating firms. No tender offered services above the minimum obligatory services.

There are default arrangements to provide remuneration to generators that do not participate or are unsuccessful in the auction. The default payments are geographically differentiated. In April 2000, the basis for remuneration changed from a split between capability and utilization payments to pure utilization payments.

The utilization payments are made at prices that change over time with the British consumer price index. Thus, in 2001/02, the default price was £1.33/MVArh and generators subject to the penalty rate were paid £0.25/MVArh. In 2002/03, this price is £1.35/MVArh, with a penalty rate of £0.27/MVArh.[18] When a generator fails to pass a reactive test, set its AVR, comply with a reactive dispatch instruction, or be capable of providing zero MVAr, the utilization payment is reduced by 80% until the failure is remedied.

### 3.4.3. U.S. – California[19]

The ISO's total payments for the reactive power provided by generators is the sum of short-term procurement payments and payments under long-term contracts.

*Short-term payments* are based on opportunity costs. In each 10-minute dispatch interval, opportunity costs are calculated as the product of: a) the amount by which the market price of real energy exceeds the generator's marginal cost of real energy; times b) the real power output reduction due to providing reactive power. The generator's marginal cost is usually taken to be its bid price for real energy, but the ISO can develop its own estimates of marginal cost to be used in place of the generator's bid.

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[18] National Grid Company [2002 pp. 11].

[19] California Independent System Operator [2000a, 2000b, 2000c].

"Supplemental reactive power" is reactive power that generators supply outside of the minimum power factor range of 0.90 lag and 0.95 lead. Subject to locational requirements, the ISO selects generators with the highest decremental Supplemental Energy Bids to reduce MW output, as such bids are used in lieu of marginal costs in determining opportunity costs. The ISO pays compensation for supplemental reactive power only if the generators must reduce MW output to achieve the instructed MVAr output.

*Long-term payments* are made to Scheduling Coordinators that provide voltage support from Reliability Must-Run Units. The payments are made if, to provide voltage support, the ISO has decreased the output of the Reliability Must-Run Units outside the power factor range in any trading interval or the ISO has requested voltage support from the synchronous condensers of the Reliability Must-Run Units.

### 3.4.4. U.S. – New England[20]

If a generator is dispatched down for the purpose of providing reactive supply and voltage control, then the unit will be compensated its Lost Opportunity Cost (LOC). The LOC calculation considers profits that the generator would otherwise have earned from sales of energy, regulation, and reserve services. Although the LOC calculation is hourly, a generator will receive compensation only if the sum of their hourly LOCs is positive over a whole day.

If there are emergency purchases of energy from external sources, generators that reduced real energy output to provide reactive power will be held harmless for the costs of the emergency purchases. Under certain conditions, the calculated LOC may include an uplift to account for other costs, such as those of motoring hydro or pumped storage generation.

### 3.4.5. U.S. – New York[21]

In New York, reactive power resources receive payments for both capacity and lost opportunity costs. Generators that fail to perform properly are penalized by cessation of their capacity payments. Capacity payments, lost opportunity costs, and generator performance requirements are summarized below.

#### *Capacity Payments*

For 2003, the annual payment to each Generator and synchronous condenser qualified and eligible to provide Voltage Support Service shall equal the product of: a) the tested MVAr capacity of the Generator or synchronous condenser; and b) $3,919/MVAr per year or a generator-specific cost-based rate.

- The $3,919/MVAr per year figure equals estimated annual reactive power costs for 2002 of $61 million divided by estimated reactive power capacity of 15,570 MVArs. The $61 million estimate is based on the fact that in 1997, just prior to significant power industry restructuring and generation divestment, the New York State generation owners'

[20] New England Power Pool [2002b, pp. 1-11].

[21] New York Independent System Operator [2002, pp. 9-22].

transmission tariffs included Voltage Support Service costs of $60 million per year. From 1997 to 2002, New York's generating capacity rose from 35,938 MW to 36,558 MW, implying a 1.7% cost increase. The 15,570 MVArs estimate is based on the system average power factor of current generators and on an accepted formulaic relationship between real and reactive power.

- The generator-specific cost-based rate is based upon amounts filed in FERC Form 1 (or equivalent). The costs that are considered include: the annual fixed charge rate associated with capital investment; capital investment in the resource supplying reactive power; and operating and maintenance (O&M) expenses for supervision and engineering allocated for supplying reactive power.[22]

Each month, generators that supply Installed Capacity are paid one-twelfth of the annual payment for Voltage Support Service. Each month, generators that do not supply Installed Capacity and synchronous condensers are paid one-twelfth the annual payment, pro-rated by the number of hours that the resources operated in that month. Payments to the parties that own rights to the output of Non-Utility Generators[23] are based on the lesser of these generators' tested reactive power production capability or their contract MVAr capability.

*Lost Opportunity Costs*

The ISO pays generators for any Lost Opportunity Costs (LOC) that they incur when the ISO directs them to reduce real power output to allow production or absorption of Reactive Power (MVAr). Lost Opportunity Costs are calculated as the product of: a) the MW of output reduction; b) the time duration of reduction; and c) the locational spot price of real energy minus the generator's real energy bid.

*Performance Requirements*

To qualify for payments, resources that provide Voltage Support Service must have AVRs and must successfully perform reactive power capability testing in accordance with the ISO procedures and prevailing industry standards.[24]

A Resource will have failed to meet its voltage support obligation if it fails at the end of 10 minutes:

a. to be within 5% of the requested MVAr level of reactive power production or absorption as requested by the ISO or the applicable Transmission Owner; or

[22] For synchronous condensers, O&M expenses include all O&M expenses. For generators, O&M expenses applicable to reactive power are all O&M expenses times 30% times (1- power factor), where the power factor is calculated at the resource's normal upper operating limit or 90% of its Dependable Maximum Net Capability (DMNC), whichever is greater.

[23] These generators have preferential legal status under the U.S. Public Utility Regulatory Policy Act of 1978.

[24] New York Independent System Operator [1999, pp 3-6].

b. to be at 95% or greater of the Resource's demonstrated reactive power capability in the appropriate lead or lag direction when requested to do so by the ISO or applicable Transmission Owner.

Suppliers of Voltage Support Service that fail to comply with the ISO Procedures will be penalized according the number of times that they have so failed.

*For an initial failure* to comply with the ISO's request for steady-state voltage control or contingency response, the ISO withholds one-twelfth of the annual Voltage Support Service payment for that failing resource, or an amount equal to the last month's voltage support payment made to the resource if the resource is not an Installed Capacity provider. For failure to comply with a steady-state voltage control request, the resources must also pay any additional cost that the ISO incurs to procure replacement Voltage Support Service as a direct result of the resource's non-performance.

*If a resource fails to comply with the ISO's request for steady-state voltage control on three separate days within a thirty-day period*, the non-complying resource is no longer eligible for Voltage Support Service payments.

*If a resource fails to comply with the ISO's request for contingency response a second time within a thirty-day period*, the ISO will withhold one-fourth of the annual capacity payment for the specific resource, or an amount equal to the last three months' voltage support payments made to the resource if the resource is not an Installed Capacity provider.

No further payments are made to repeatedly violating resources until the ISO is satisfied that the resource has successfully performed a reactive power capability test, and until the resource has provided Voltage Support Service for thirty consecutive days without any compliance failures and without compensation.

### 3.4.6. U.S. – PJM

There are two distinct generator reactive power products in the PJM market: reactive power capability at rated generator output and reactive power provided at reduced generator output. Reactive power capability at rated generator output is the component that is incorporated into and compensated through the PJM Tariff. Control systems on generators react automatically to changing system conditions and increase or decrease generator reactive power output as needed to maintain local voltages within a bandwidth.

For their reactive power services, the Transmission Provider makes a monthly payment to each generation owner equal to the generation owner's monthly revenue requirement as accepted or approved by the Commission. If a generation owner sells a resource that is included in its revenue requirement, payments for that resource transfer to the new owner.[25]

A generator owner's revenue requirement is broken down into two components: fixed costs attributable to the generators' reactive power production capability; and increased generator and step-up transformer heating losses that result from the generators' production of reactive power.[26] *The fixed costs* consist of fixed plant costs for those facilities that are needed to provide

[25] PJM Interconnection [2002, pp. 224-226].

[26] Dominion Resources [2003 pp. 3-8].

reactive power. The relationship between real and reactive power output is used to determine the portion of plant costs that should be assigned to the provision of reactive power. The annual revenue requirement is determined by applying an annual carrying charge to the total amount of plant investment associated with providing reactive power. *The heating losses* are those associated with the armature winding and field winding of the generator as it produces reactive power. There are also heating losses through the generator step-up transformer.

#### 3.4.7. U.S. – Texas

Generators are required to provide voltage support without compensation in the range 0.95 leading or lagging at all times they are on-line. If ERCOT instructs a generator to reduce its real power output so that it can provide reactive power, that generator will be paid for its lost real energy sales at the greater of the market real energy price ("Out Of Merit Energy Down") for the generator's zone, the generic fuel cost applicable to the generator, or zero. If system reliability is at risk, however, there is no compensation. If ERCOT instructs a generator to provide reactive power outside of its required range, ERCOT will pay for the additional reactive power at a price that recognizes the avoided cost of reactive support resources.

### 3.5. Allocation of Reactive Power Costs

We begin this section by summarizing the findings of two surveys of reactive power cost recovery, one by Alvarado *et al* [1996] and the other by Dingley [2002]. We then directly survey the cost recovery methodologies of several regional power systems.

#### 3.5.1. Findings of the Survey by Alvarado *et al*

Alvarado *et al* [1996] look at the retail tariffs of eighty U.S. utilities. They find there are three general methods by which utilities recover reactive power costs.

*First, most U.S. utilities charge according to reactive power use* as measured by either maximum reactive demand (in kVAr) or (to a lesser extent) by total reactive energy (in kVArh). Of the U.S. utilities with reactive power charges, over half use the kVAr billing determinant. For these utilities, the reactive power charge is proportional to the amount by which the customer's maximum reactive power demand exceeds a threshold. The level of the threshold varies substantially among utilities, with values ranging between 10% and 62% of peak real power demand, and with an average value around 50% of real power demand, equivalent to an 89% power factor. The charge per unit of excess also varies substantially among utilities, ranging from $0.10 to $1.75 per kVAr, and averaging $0.43. There is no necessary relationship between an individual utility's threshold and per-unit charge.

Half a dozen utilities charge according to reactive *energy* consumption, using the kVArh billing determinant. For these utilities, the reactive power charge is proportional to the amount by which the customer's reactive energy consumption exceeds a threshold, where the threshold is defined as a percentage of real energy consumption.

Some utilities offer variations on these reactive power charges. Some provide an incentive for their customers to improve their power factor by offering credits when a customer's reactive power demand is less than the threshold. Other utilities offer reactive power charges that have ratchets, whereby maximum reactive power use in the past eleven months may determine the current month's reactive power charge.

*Second, some U.S. utilities charge for reactive power by adjusting the customer's real power billings*. This may be done by increasing the customer's real power billing demand (kW) or real energy billing consumption (kWh) when their power factor falls below a trigger power factor. For example, if the trigger power factor is 85%, a customer with a 10 MW peak load and a 75% power factor would be charged for 11.33 MW (=10*0.85/0.75) of real power peak load. Most utilities have trigger power factors of 85% or 90%, with an average of 86%. Two utilities adjust real energy consumption rather than real power demand.

*Third, other U.S. utilities use a variety of miscellaneous cost recovery methods.* These include adjustments to the total bill, customer charges, real power energy charges, and real power demand charges. For most utilities, the adjustment is based on the relationship between a trigger power factor and the customer's actual power factor. Other utilities have tariff-specified bill multipliers that vary by power factor in complex fashions.

Because the utilities pricing methods and parameters are so very different, they result in an astonishing variation in charges for reactive power service. For example, a hypothetical 1 MW customer with a 70% load factor and an 80% power factor could pay anywhere between zero and $3,520 per month, depending solely on the utility from which it gets power. Even under the most common type of reactive power tariff, the range is $19 to $438 per month. This large variation reflects a variety of seemingly arbitrary inconsistencies among tariffs. There can even be widely varying tariffs approved by a single regulatory commission within the same state: for example, the hypothetical 1 MW customer would pay $375 to one Iowa utility but only $120 to a different Iowa utility.

As a group, the reactive power tariffs of U.S. utilities have three significant flaws. First, they recognize only localized costs, not the reactive power costs that are incurred throughout the power system in amounts that may not be related to the chosen billing determinants (kVAr, kVArh, kW-to-kVA ratios, and power factors). Second, they fail to recognize how rapidly varying loads affect reactive power costs. Third, the tariffs are wildly inconsistent.

### 3.5.2. Findings of the Survey by Dingley

Looking at 45 utilities in 12 countries, Dingley [2002, p. 1] finds "a clear split between the preference in the USA for kVAR and kVARh based charges and the preference elsewhere for kVA-demand tariffs." He divides reactive power charges into six types:

a. Based on maximum apparent power demand (kVA);

b. Based on the maximum reactive power demand (kVAr), usually at the time of maximum real power demand, often applied using a threshold level;

c. Based on reactive energy consumption (kVArh) over the billing period, often using a threshold level, and sometimes differentiated by season, time-of-day, or power factor;

d. Based on either average power factor or power factor at the time of maximum demand. Charges are adjusted according to power factor, often using a threshold level, sometimes in a relatively complex way;

e. Based on a minimum required power factor, below which the utility is entitled if necessary to install power factor correction equipment at the customer's expense; and

f. No charges.

Table 6, which is directly from Dingley [2002, p. 9], classifies the large-user tariffs offered by the 31 utilities that have a bundled supply and delivery service. The columns indicate into which of the six classifications that each utility's tariff falls. The right-most column indicates whether a power factor threshold level triggers charges.

Table 6 "shows that basing reactive power charges on the maximum apparent power (kVA) demand over a billing period is common outside the USA, while not a single USA utility included in this scan uses this method. On the other hand, while 12 of the 15 USA utilities scanned base their reactive power charges either on the maximum reactive power (kVAR) recorded over a billing period, or on average or peak power factor, these approaches were not found outside of the USA. Furthermore, the scan shows that of the 12 USA utilities using the kVAR or power factor approaches, 9 allow a degree of latitude (usually down to a threshold power factor of 0.90) before the reactive power charges are applied. By contrast, all 10 utilities (all outside the USA) using the maximum kVA-demand approach apply the charges as soon as there is any deviation from unity power factor." (p. 10)

**Table 6**
**Tariffs for Bundled Supply and Delivery Services, per Dingley [2002, p. 9]**

| Country | Utility | Reactive charges based on | | | | | | Thres-hold |
|---|---|---|---|---|---|---|---|---|
| | | max kVA | max kVAr | kVArh | P.F. 1 | P.F. 2 | No charges | |
| Canada | BC Hydro | X | | | | | | All |
| | Richmond Hill Hydro | | | | | | X | |
| | Toronto Hydro | X | | | | | | All |
| France | Electricite de France | | | X | | | | All |
| India | Gujarat EB | | | X | | | | All |
| | Himachel Pradesh EB | X | | | | | | All |
| | Maharashtra SEB | X | | | | | | All |
| | Rajasthan SEB | | | | | | X | |
| | Tamil Nadu EB | X | | | | | | All |
| Jamaica | Jamaica PS Co. | X | | | | | | All |
| Malaysia | Tenaga NB | | | | | | X | |
| Singapore | Singapore Power | | | X | | | | 0.85 |
| S Africa | City of Cape Town | X | | | | | | All |
| | City Power (Jo'burg) | X | | | | | | All |
| | plus | | | X | | | | 0.96 |
| | Ethekwini (Durban) | X | | | | | | All |
| | Eskom - demand tariff | X | | | | | | All |
| | Eskom - TOU tariff | | | X | | | | 0.96 |
| USA | AEP Indiana Michigan | | | | X | | | All |
| | AEP - Ohio | | X | | | | | 0.90 |
| | AEP - Texas | | | | X | | | 0.90 |
| | Anonymous | | X | | | | | 0.90 |
| | Arizona PSC | | | | X | | | 0.90 |
| | Com Ed Illinois | | | | | X | | 0.85 |
| | Jersey Central P&LC | | X | | | | | All |
| | Kansas City P&LC | | X | | | | | 0.90 |
| | Los Angeles DW&P | | | X | | | | 0.995 |
| | Pacific - California | | X | | | | | 0.93 |
| | Pacific - Utah | | | | X | | | 0.90 |
| | San Diego G&E | | X | | | | | 0.90 |
| | Tampa Electric | | | X | | | | All |
| | Xcel - Colorado | | | | | X | | 0.90 |
| | Xcel - Minnesota | | | | X | | | 0.90 |

Dingly concludes: "(i) There is no clear international consensus on a 'correct' way of charging for reactive power in a bundled supply and delivery environment. (ii) Because of the many variables affecting the value or cost of reactive power, a cost-reflective charging method would need to be hugely complex. (iii) There are no international examples of the implementation of a fully cost-reflective charging method for reactive power, even in the most advanced market environments. (iv) The cost of reactive power is of the order of one percent of the total cost of electricity, so that imperfections in cost-reflectivity in reactive power charges are swamped by even minor imperfections in the cost-reflectivity of other components of the total charge." (p. 22)

### 3.5.3. Survey of Regional Power Systems

The restructured markets recover reactive power costs that are set sometimes according to payments to reactive power resources, and other times according to administratively determined levels. Long-term (capacity) costs are sometimes recovered separately from short-term costs. Most costs tend to be recovered through per-MWh charges on all loads, but they are also recovered through charges on reserved (nominated) peak kVAr demand or actual peak kVAr demand.

***In New Zealand***, Transpower annually revises its voltage support charges for consumers. Most consumers pay on a per-kWh basis. Because the costs of providing voltage support are highest in the north part of the North Island, the highest rates apply in this region.[27]

Distributors pay three voltage support charges. These are a nominated peak charge, an actual monthly peak charge, and a residual charge. *The nominated peak charge* equals the nominated kVAr rate, times the kVAr peak specified by the distributor. *The actual monthly peak charge* is a penalty charge. It equals the penalty rates times the excess of the actual kVAr peak over the nominated peak. The actual kVAr peak is calculated as the average of the six largest kVAr peaks for the distributor in each month, but no more that two kVAr peaks in any one day, and including only kVAr demands during on-peak periods (non-holiday weekdays between the hours of 07:00 to 21:00 inclusive). *The residual charge* recovers all remaining costs from all load on a per-kWh basis.

***In the U.K. (England and Wales)***, the National Grid Company (NGC) is subject to an incentive scheme that limits the amount of Reactive Power Uplift that it can recover from customers in any year. The allowable Uplift is partly based upon actual reactive power costs and partly based upon target reactive power costs.

***In California***, there are two voltage support charges.[28] Both charges vary by zone.

For each geographic zone, the short-term voltage support rate in each 10-minute trading interval equals: a) the total lost opportunity costs for that interval and that zone; divided by b) the total MWh load (including exports) for that interval and that zone. The charge paid by each customer equals the zonal rate for that interval times the customer's MWh load in that interval and that zone.

For each zone, the long-term voltage support rate for each month equals: a) the total payments by the ISO to Reliability Must-Run generators in that month and that zone; divided by b) the total MWh load (including exports) for that month and that zone. The charge paid by each customer equals the zonal rate for that month times the customers MWh load in that month and that zone.

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[27] Grid Security Committee Ancillary Service Working Group [2000a, pp.11-13].

[28] California Independent System Operator [2000c, pp. 20-25, 2000d, pp. 4-7].

***In New England***, each hour's reactive power costs are shared among customers according to their relative shares of Network Load plus Reserved Point-to-Point Capacity for that hour.[29] The costs that are shared are the sum of capacity costs for the hour, lost opportunity costs for the hour, and energy costs used by all resources to provide reactive power during the hour.

***In New York***, the rate for Voltage Support Service is constant within each year, and is updated annually.[30] It equals the year's forecast payments to generators that provide voltage support (adjusted for any under- or over-collection from the preceding year) divided by the year's forecast MWh load (including exports and wheel-throughs). The payment by any customer equals their actual load times the rate.

The 2002 rate for Voltage Support Service is $0.34 per MWh. This reflects a forecast cost of $61 million, an over-collection in 2001 of $6.5 million, and forecast 2002 load of 162,500,000 MWh.[31]

***In PJM***, the costs of Reactive Supply and Voltage Control from Generation Sources Service are allocated among transmission customers according to the size of the monthly peak MW loads that they serve (including average point-to-point transmission service energy reservations) relative to the sum of the monthly peak loads of all transmission customers.[32] The reactive power rate is therefore, in effect, a real power demand charge. The charge is differentiated on a zonal basis. It is partly allocated on the basis of reserved MW capacity rather than solely on monthly peak MW loads.

With FERC approval, transmission owners have quantified revenue requirements associated with the portion of their generation plant that is related to voltage control. Only a relatively small part of their generation revenue requirement is collected through the resulting reactive power tariff. Reactive power rates are different for each transmission owner, and average $105/MW-month or $0.3030/MWh on peak.

***In Texas***, voltage support costs are shared among load-serving entities on a Load Ratio Share basis.

## 4. OPTIONS FOR UNBUNDLING REACTIVE POWER SERVICE IN ALBERTA

In creating this project, the TA stated that the project's purpose is to determine "if there is merit in creating a separate unbundled tariff mechanism for the revenue and cost allocation of reactive power as an identifiable Ancillary Service." Whether there is merit in unbundling depends primarily upon whether (and how well) unbundling can help Alberta obtain needed investment in reactive power equipment and induce efficient real-time dispatch of its stock of reactive power equipment. If Alberta's present market structure has resulted or threatens to result in deficient reactive power investment or inefficient dispatch, unbundling might help resolve these problems.

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[29] New England Power Pool [2000b, pp. 272-275].

[30] New York Independent System Operator [1999, p. 7].

[31] $0.34 = ($61,000,000 - $6,500,000) / 162,500,000

[32] PJM Interconnection [2002, pp. 224-226]

Other factors that might be considered as drivers for unbundling are fairness concerns and government policy in encouraging market structures over regulatory structures. "Fairness" would allow generators a reasonable opportunity to fully recover the costs of the reactive power services that they provide, and would give consumers a reasonable chance of eventually seeing lower reactive power costs. Government policy should seek a combination of market structures and regulatory structures that eventually lead to the greatest consumer benefits (in the forms of better service and lower prices).

Although we have not examined the specific physical configuration of Alberta's power system, we are fairly certain that the system will not support short-term competition in reactive power service, where "short-term" is the period before which new reactive power resources can come on-line. We have two reasons for this expectation. First, in most power systems there are few locations at which reactive power resources are owned by a sufficiently large number of suppliers: there are simply not enough local competitors to make competition work. Second, Alberta's power system has low load density, meaning that the load level is low relative to geographic area. This implies that Alberta's reactive power market will tend to be even less competitive than that of other power systems. Thus, any unbundling of Alberta's reactive power service should not be predicated on the notion that workable competition is possible in a short-term reactive power market, but should instead aim to facilitate the provision of reactive power in a manner that is consistent with competition in real power services.

Because we have neither examined Alberta's data nor conducted quantitative analysis of the province's power system and tariffs, we are not presently able to determine whether Alberta's present reactive power arrangements merit reform. If Alberta does make such a determination, however, we recommend that the reform measures include nine basic elements. The elements related to the supply of reactive power by generators are as follows:

1. *Minimum reactive power capability requirements*. As a condition of market participation, on-line generators would be required to provide a minimum level of reactive power service through automatic devices. This minimum requirement would allow some level of non-performance due to normal maintenance requirements and outage risks. Generators that cannot satisfy the minimum requirement would be charged for the value of the reactive power service that must instead be provided by other resources.

2. *Availability requirement*. As a condition of market participation, generators would be required to schedule maintenance so that they can provide reactive power at critical times (if any). They would also be required to be available to produce reactive power at an acceptably high reliability level.

3. *Penalties for non-performance*. When generators fail to meet their obligations or to follow TA instructions, they would pay penalties. The TA would establish a testing procedure for determining whether generators meet the minimum reactive power capability requirements and the availability requirement.

4. *Compensation for capital costs*. If the TA asks generators to make investments that extend their reactive power capabilities beyond the minimum, the TA would provide compensation for the costs of the incremental capability. This compensation would give the TA the right to dispatch the generator's reactive power, with additional compensation for variable costs.

5. *Compensation for variable costs*. The TA would compensate generators for their variable costs (including opportunity costs) in two situations. First, when instructing generators to provide reactive power beyond minimum requirement levels, the TA would compensate generators for the variable costs incurred due to going beyond the minimum. Second, when committing generators so that they can provide reactive power or reactive power reserves, the TA would compensate generators for start-up costs and otherwise uncompensated costs (such as minimum loading costs).
6. *Transmission Administrator resources*. The TA should have the right to procure and manage its own reactive power equipment – or to direct Transmission Facility Owners (TFOs) to do so – in cases wherein the preferred resources are not available from generators and other market participants. This right is needed to mitigate generators' potential exercise of market power in the long-term reactive power market, which it accomplishes by making substitute resources available to the TA. The TA should be required to justify such investments by demonstrating that either: a) the needed resources are not available from non-TFO parties; or b) the TA is capable of procuring the resources (or the resulting reactive power services) more cheaply if it does so directly (or through TFOs) rather than through non-TFO parties.

The elements concerning recovery of the costs of reactive power service, including costs from both generation and non-generation sources, are as follows:

7. *Charges for direct reactive power consumption*. For using reactive power outside of a standard power factor range, the customer should pay a charge based upon some combination of peak kVAr and total kVArh consumption. This approach would provide incentives for customers to install their own reactive power compensation equipment.
8. *Special voltage charges*. When a market participant's behavior or characteristics creates significant voltage control costs, it may be appropriate to levy a special charge on that participant. Circumstances that can create such special voltage needs can include: a) rapidly varying production or consumption of real power; and b) participant locations not readily reachable without special reactive power compensation schemes.
9. *Uplift charges*. For all reactive power and voltage control costs that are not recovered through the two preceding charges, there would be an uplift charge. These costs are primarily associated with the need to provide reactive power throughout the system to support real power flows.

Alberta's "options" for unbundling lie in the choices that can be made in implementing each of these elements. We discuss each of the elements and their options below.

### 4.1. Minimum Reactive Power Capability Requirements

Alberta presently requires generators to be capable of producing and absorbing reactive power within a 0.90 lagging and 0.90 leading power factor range[33], and to have automatic voltage regulators on automatic voltage control mode and power system stabilizers. These requirements

[33] Generation covered under the legislated PPA regime has power factor commitments that deviate somewhat from these more standard amounts.

are similar to what other regions require, and do not impose an undue burden on generators in the sense of forcing them to forego significant sales of real power. These requirements serve the important purpose (among others) of helping mitigate generator market power, as generators cannot manipulate the non-existent price of reactive power within the required range.

Although most generators have comparable dynamic response characteristics, special consideration may be given to those that provide reactive support that is slower, lumpier, faster, or more dynamic than the norm. The feedback response speed associated with generator exciter systems is generally sufficient and adequate for most reactive power regulation needs. However, under some conditions slower and lumpier forms of reactive supply may suffice (shunt capacitors and reactors), while under some other circumstances a faster degree of responsiveness would be required (such as the responsiveness associated with devices such as SVCs and STATCOMs).[34]

Although we are not aware of any compelling reason for Alberta to change its ±0.90 power factor requirement, studies could be undertaken to analytically identify the optimal power factor range. In principle, this requirement should be set so that generators help meet, at least cost, the system's requirements for voltage regulation capabilities and reactive power reserves. The considerations that would underlie any changes in the capability requirement would include:

- the system's voltage control needs;
- generators' costs of providing voltage control;
- the requirement's expected effects (if any) on generators' investments in voltage control capability;
- the requirement's expected effects (if any) on the effectiveness of generator dispatch of reactive power; and
- the ease or difficulty of changing the current requirement to a new requirement.

The needs assessment could imply the minimum portions of reactive supply that are allocated to generators, dynamic devices, and slow devices, respectively.[35] The proportions of these resources for each region should depend on the characteristics of the system, characteristics of the loads, power quality objectives (tolerable flicker, for example), and other such considerations.

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[34] Metrics for characterizing the "speed" attribute associated with reactive power and voltage regulation are not very common or well developed. The need for speed has traditionally been classified according to rates of response or the ability to use feedback loops for voltage regulation.

[35] *Generators* can be brought on line relatively slowly (minutes to hours); but once on line they regulate voltage using a feedback loop that can respond in the order of a few cycles. *Dynamic devices* can be brought on line very quickly and they can respond to changes in reactive demand in the order of milliseconds. *Slow devices* must be brought on line more slowly.

### 4.2. Availability Requirement

As a condition of market participation, generators would be required to be available at certain times and with a defined level of reliability. This condition is needed to assure reliability and to mitigate any market power that might be exercised by withholding reactive power capacity.

*The timing requirement* would have generators schedule maintenance so that they can provide reactive power at those times when, based upon actual or anticipated system conditions, the TA determines that their reactive power capability is most needed. Because maintenance scheduling can impose opportunity costs on generators, the TA should allow as much freedom in scheduling as possible. If the reactive power services of two or more generators can substitute for one another, the scheduling can seek to coordinate maintenance for the mutual convenience of the power system and of the substitutable generators.

*The reliability requirement* would have generators be available to produce reactive power during non-maintenance periods at a reliability level that is determined and monitored by the TA. The generator's response characteristics must satisfy the minimum reactive power capability requirements and, if applicable, the conditions of any contracts for incremental capability beyond the minimum.

### 4.3. Penalties for Non-Performance

Penalties are needed to induce generators to follow the rules, and to compensate the TA for any costs that might be incurred to resolve any reactive power deficiencies that might arise from generators' delinquency. There are two basic issues.

*First, what behavior should incur a penalty?* Behavior should incur a penalty only if it increases expected system costs, reduces power quality, or risks reliability. Options for the behavior subject to penalty include:

- Failure to meet reactive power capability requirements.
- Failure to operate automatic voltage regulators on automatic voltage control mode and power system stabilizers.
- Failure to follow reactive power dispatch instructions in a timely manner.

*Second, what should the penalty be in different situations?* In principle, penalties should at least equal the expected costs of the damages caused by misbehavior, and should exceed these expected costs to discourage misbehavior. In practice, the penalties should be high enough to discourage misbehavior, but low enough to avoid imposing significant financial risk on generators. Options include:

- For behavior that violates WECC requirements, generators could pay at least the WECC penalty.
- For performance failures, penalties could equal one or more months of capacity payments.
- For repeated performance failures, the penalty could be suspension of capacity payments and/or re-evaluation of the generator's reactive power capability.

- Penalties on reactive power not delivered could be at least equal to the locational spot value of reactive power, if it can be determined.

The first three options yield prices that are poorly related to damages. The fourth option is closely related to damages, but is difficult to calculate.

For those generators that are unable to meet reactive capability or performance requirements at reasonable cost, it may be reasonable for the penalties to be set equal to the costs that the TA incurs to obtain equivalent services from other resources.

### 4.4. Compensation for Capital Costs

Reactive power prices should allow the providers of reactive power services a fair chance of recovering their costs, including a "normal" return on capital. This is particularly important to assure an adequate supply of reactive power, notably including reserves that may rarely provide reactive power but nonetheless enable the power system to withstand certain contingencies.[36]

Determining appropriate compensation raises at least four questions.

*First, should generators be paid for all of their capital costs, or only that portion that exceeds the minimum reactive power capability requirements?* We believe that payments to generators should only cover the capital costs on the portion of capability that exceeds the minimum requirements. This is consistent with the basic logic of having minimum requirements, and avoids the administrative costs of estimating capital costs for most generators.

*Second, should generators be paid separately for capital costs than for variable costs?* Because generators incur both fixed and variable costs in providing reactive power service, it would reduce their risk to receive capacity payments related to reactive power capability and variable payments related to reactive power output. Capacity payments would provide a mechanism by which the TA could assure that adequate reactive power resources are available long-term, thereby providing stability in reactive power costs and mitigating potential market power problems in reactive power service. For these reasons, we find a compelling case in favor of separate payments for generators' capital and variable costs of providing reactive power.

*Third, what conditions would make generators eligible for capacity payments?* The basic condition needs to be that the TA and the generator have agreed upon eligibility and upon the terms under which the capacity will be available to the TA. Such an agreement would be reached only when the TA finds that reactive power from a particular generation resource would be cheaper than that available from other generation and non-generation sources. This raises the problem of determining the price and non-price terms of agreement, and whether the TA might be able to compel a generator to make an investment in incremental reactive power capability if agreement is not forthcoming. In the absence of market power concerns, terms could be determined through a competitive procurement process. In the normal situation in which market power *is* a concern, however, there would need to be cost-based rules for setting prices.

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[36] Many reactive resources are needed exclusively for meeting contingencies rather than for meeting the needs of the power system under base case conditions. Contingency constrained operation criteria can be used to readily determine the amount of needed (but not necessarily used) reactive power injection.

The TA would have no right to call upon capability for which the TA has not made capacity payments, even if the generator has such capability. This provision is necessary to assure that the TA pays for reactive reserves that the TA rarely or perhaps never uses, but that nonetheless have value to the TA and to the power system.

*Fourth, how should the capital costs attributable to reactive power be determined?* Negotiating reactive power capacity costs is challenging because it involves negotiations between bilateral monopolists. On the one hand, the generator might be the only possible source at a particular location, which might encourage it to attempt to exercise market power by demanding payment far in excess of cost. On the other hand, the TA, which is always the only buyer, might underestimate the generator's cost.

There are several options for determining capital costs:

- Reactive capacity auctions might be used as a market-based approach for revealing generators' reactive power costs. Unfortunately, auction results in other regions have sometimes been unimpressive, and the location-specific need for reactive power might well allow auction prices to be subject to market power.
- Incremental capital costs could be used as a lower limit on the value of generators' reactive power capability. These costs might be estimated as the difference between the capital costs of the generator with the *desired* reactive power capabilities and its capital costs with the *minimum* required capabilities. Such estimation would require identifying the extra equipment required for the desired capabilities, or allocating the costs of particular pieces of equipment among incremental reactive power capabilities, minimum reactive power capabilities, and real power capabilities.
- The costs of non-generation equipment (e.g., capacitor banks, reactors, and synchronous condensers) could be used as an upper limit on the value of generators' reactive power capability. The relevant alternative would be the equipment that can provide, at least-cost, reactive power services that are equivalent to those provided by the generator.
- For equipment and facilities that provide both reactive and real power, relationships between reactive power (MVAr), real power (MW), and apparent power (MVA) capabilities can be used as the basis for separating reactive power costs from real power costs.
- Generic *pro forma* engineering studies of generation plant could be used as the basis for separation of reactive power costs.

These imperfect options are not mutually exclusive. The best approach for Alberta may be a combination of options. For example, Alberta might with to consider auctions capped at the cost of the least-cost alternative. For situations in which competitive auctions are not workable, negotiations could begin at estimated incremental costs.

### 4.5. Compensation for Variable Costs

Depending upon circumstances, the provision of reactive power services may cause a generator to incur both variable costs (such as active losses in the generator and in the step up transformer) and opportunity costs (due to lost sales of real power, regulation, or reserve services). If the TA commits a generator for the purpose of providing reactive power or reactive operating reserves, the variable costs would also include that portion of the generator's start-up and shutdown costs that are not recovered from payments for energy and reserve.[37] Estimation of all of these costs should be fairly straightforward.

To hold generators harmless from these costs and to induce generators to provide reactive power, we believe that TA should compensate generators for the variable costs of providing reactive power that are provided in response to the TA's instructions. This raises at least two questions.

*First, should compensation apply to all of the reactive power provided, or only to that portion in excess of the minimum requirement?* On the one hand, compensation for all the reactive power is arguably fair and provides appropriate incentives for generators to provide the service. On the other hand, the variable costs incurred to meet the minimum requirement tend to be trivial, and compensating only the excess over the minimum requirement will avoid the administrative costs of estimating variable costs for most generators.

*Second, should compensation be based on the generator's variable costs or on the locational spot value of reactive power?* If dispatch is efficient, the locational spot value will always be at least as great as the variable cost, and payments based on locational spot value will provide generators with incentives to provide reactive power service. On the other hand, locational spot values are difficult (though not impossible) to calculate with today's computer technology. For the time being, at least, compensation based on variable costs will have to do.

### 4.6. Transmission Administrator Resources

The TA should have the right to procure and manage its own reactive power equipment – or to direct TFOs to do so – in situations in which the preferred resources are not available from generators and other market participants.[38] Such situations can occur for several reasons. First, the most appropriate equipment may be of a type (e.g., capacitors, synchronous condensers, SVCs, and STATCOMS) that is not ordinarily provided by generators and other market participants. Second, the TA (or a TFO as its agent) may be able to procure and site a particular resource faster than it can be procured and sited by another party. Third, direct procurement can allow the TA to circumvent (and thereby mitigate) the exercise of market power by other parties.

### 4.7. Charges for Direct Reactive Power Consumption

For power factor correction at interconnections with customers (distributors or consumers), the costs of correcting power factors outside of a standard range would be recovered from the particular customer with the out-of-range power factor. A positive range (such as 0.90 lagging to 0.90 leading) would mimic the general U.S. approach, while a zero range (limited to the 1.00

[37] Start-up costs should include all costs associated with unit start, including wear-and-tear, reduced availability, and expected loss of generator life.

[38] The TA's obligation to plan the reliable operations of the Alberta system may already give the TA all or part of this right to plan and procure reactive power equipment or services.

power factor) would mimic the general non-U.S. approach. In either case, the customer would pay a charge based upon some combination of peak kVAr and total kVArh consumption.[39]

In principle, the charge should be based upon the lesser of the costs of the equipment (such as capacitors) that is needed to correct the problem, or the locational spot value of providing the reactive power needed to serve the customer. In the absence of information on locational spot values, the more practical approach is to use the costs of the power factor correction equipment.

Power factor correction charges need not include any penalties unless there is some reliability risk. The point of these charges is to make sure that costs are paid by the customers who cause these costs to be incurred, and to encourage customers to self-provide cheaper solutions if they can. If the customer's behavior is creating a reliability risk, however, the power factor correction charge might be set to discourage the inappropriate behavior.

## 4.8. Special Voltage Charges

When a market participant's behavior or characteristics creates significant voltage control costs, it may be reasonable to levy a special charge on that participant. Circumstances that can create such special voltage needs can include: a) rapidly varying production or consumption of real power; and b) distant location.

### 4.8.1. Rapidly Changing Real Power Production and Loads

Some abnormal and very costly voltage problems arise from certain generators (e.g., wind turbines) or consumers (e.g., arc furnaces) that have erratic real power production or consumption. The effect of this behavior is to create rapidly changing real power flows throughout a transmission network (or a portion of the network), which often creates a need for expensive dynamic reactive power compensation throughout the network as well as larger reactive power reserve margins.[40]

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[39] Whenever voltages are within normal ranges and power factors are near unity, there is little cost to reactive power. That is, there is very little difference to the system (hardly noticeable) between a load with a power factor of 1 and one with a power factor of 0.99. However, as the departure from unity increases, the costs associated with this departure rise quadratically, and even more dramatically in cases where line flow limits or voltage limits are reached.

Likewise, since most generators are designed to operate at constant terminal voltage, there is generally very little additional cost to a generator designer to provide a minimal amount of reactive power supply capability. It is only when the amount of reactive power goes outside some "window" that there are nontrivial costs to the generator designer and supplier. In fact, at some point these costs become noticeable for operations. Costs of providing reactive power by generators are always positive, as increased field and armature currents associated with low power factor operation decrease the internal efficiency of the generator. However, these effects tend to be negligible around a band near unity power factor.

[40] The regulation of voltages throughout the system is performed primarily by adjusting reactive power injections. The need for voltage regulation arises as a result of departures or excursions of the voltage outside some normal range. In some cases the evolution of the voltage to a range outside the normal range is gradual. Gradual changes in voltage call for either gradual or at least intermittent adjustments of reactive injection. In some other cases, voltages can change drastically in a very short time period. Such a condition can arise as a result of a sudden connection or disconnection of a load or generator. It can also arise as a result of the outage of a line or transformer or some other piece of system equipment. Or it can arise as the result of sudden and erratic changes in demand (as in the case of

In principle, generators and consumers who create these problems and costs should pay for them. It is partly a matter of fairness, since they are the parties who create the costs by imposing on the power system a need for extra or special voltage control equipment. It is also a matter of efficiency, because these parties can often respond to price incentives to improve their behavior and can thereby reduce the power system's costs.

In practice, there are two difficulties in determining the charges for abnormal voltage problems. First, it is technically challenging to estimate the costs associated with the rapidly changing outputs and loads of erratic generators and consumers. Getting a reasonable estimate requires power flow analyses of costs with and without the erratic behavior under a variety of system conditions; and the estimates are subject to error. The second difficulty is political: a generator or consumer that is large enough to create a voltage problem may be able to prevent imposition of appropriate sanctions.

### 4.8.2. Locational Aspects of Reactive Supply

Suppliers and consumers that are in locations that require special voltage regulation services should bear the associated costs if the costs significantly differ from those of most other suppliers and consumers. For example, remote generation facilities may require special reactive power compensation schemes, possibly in the form of static VAR equipment or other fast-responding VAR resources, along the long lines that connect them to the main power grid. Another example would be a large load located far away from any sources of reactive power supply, requiring the installation of special equipment or the frequent use of out-of-merit dispatch in order to meet the requirements of the load.

The customer's need for reactive power can vary a great deal according to their location. Long transmission lines or medium length cables have the tendency to have poor voltage regulation characteristics. This means that the longer the line or cable that connects a customer to the grid, the more the voltage at the receiving end will tend to change as a result of changes in both active and particularly reactive power consumption at the receiving end. The bottom line is that the rate of change in voltage as a result of a change in power injection cannot become excessively large. Even an infinite amount of reactive power at the sending end will do no good to the regulation of voltage at the receiving end when the reactive resource needs to be at or near the receiving end. In the case of long lines, reactive resources in the middle of the line are also required.[41]

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arc furnaces). Whatever the reason, sudden changes in voltage may require rapid adjustments in reactive power injection. Lumpy or slow adjustments in reactive injections may lead to either undesirable voltage flicker or (in extreme cases) voltage collapse. Even when voltages are always entirely within the acceptable and normal range and never have any excursions outside this range, sudden changes of voltage can be quite disruptive to both humans and machines. Thus, an important attribute of the regulation of voltage is the speed of response of the equipment intended to adjust the voltage, and the speed with which a particular load may change its demand for active or reactive power.

[41] One way to characterize the locational aspects of the need for reactive power support throughout the grid is through formal determination of the change in voltage (dV/dP or dV/dQ) that accompanies change in real or reactive power injection. Such a determination can be done based on uses of the system Jacobian matrix, properly constructed to recognize which locations have reactive support and which locations do not.

### 4.9. Uplift Charges

Power factor charges and abnormal voltage charges will recover only a part of total reactive power costs. The remainder must be recovered through some sort of uplift. The usual way of charging such an uplift is through a uniform real energy charge (MWh) or real demand charge (MW) on all load and exports, usually buried in transmission charges or bundled service charges. Other options include charges on peak apparent power demand (MVA), peak reactive power demand (MVAr), or nominated reactive power demand (MVAr).

We believe that uplift charges based upon real power usage are appropriate because most reactive power costs are related to the transmission system flows that arise from real power loads. The portion of reactive power costs that are related to direct reactive power usage can be recovered through the charges for direct reactive power consumption that are described Section 4.7.

Alberta may wish to consider differentiating uplift charges by load zone and by consumer type. The costs of providing reactive power in support of transmission flows can be very different for the consumers located in different zones. Because the time patterns and variability of loads differ among different types of consumers, the costs of providing reactive power can also differ among different consumer types. Power flow studies can – with some difficulty and some imprecision – estimate these cost differences.

## 5. CONCLUSIONS

The main potential benefit of unbundling reactive power service is that, by making costs more transparent, it may encourage greater efficiencies in the provision and use of reactive power. On the other hand, an important constraint on the manner of unbundling is that reactive power supply is generally not competitive, at least in the short run. The potential exercise of market power by generators may be substantially mitigated by a combination of minimum capability requirements, minimum availability requirements, and authorization for the TA to procure reactive power from non-generation sources.

The question of unbundling reactive power service is about how reactive power supplies should be organized and priced and how reactive power costs ought to be recovered from consumers. This question can be answered both with and without formal unbundling. The literature and the experience of other power systems offer numerous ideas about detailed ways in which Alberta

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A second way to characterize the reactive power characteristics of a given system location is the use of the "Short Circuit Ratio" (SCR) as an indicator of when a particular system location may be in need of additional reactive power support. The SCR is easily calculated. There is a strong coupling between how "weak" the system is (a system is weak when its SCR is low, such as below 4) and how much the voltage will flicker or vary as a result of potentially even small changes in injection, either real or reactive. In other words, the weaker the system is, the more important it becomes to have the ability to rapidly regulate the voltage. That is, it is not sufficient to have the right amount of raw reactive power at a given location (say by having lots of shunt capacitors). It is also important to have the right kinds of reactive power support.

A rational tariff for reactive power procurement must take into consideration not only the system location but also the anticipated needs of the various types of reactive power that will be needed at that location. While there is some substitutability between locations, this ability to replace one MVAr at one location with a corresponding MVAr at a different location diminishes rapidly as we move away from the first location.

might take modest steps to improve the incentives for efficient investment in and dispatch of reactive power supply, and for efficient consumption of reactive power. Alberta needs to determine whether any of these options are sufficiently superior to warrant modifications to its current system.

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