Environmental Quality Council
Energy Subcommittee
December 10, 2001
Exhibit 7

The Montana Electric Transmission Grid
Operation, Congestion and Issues

Briefing Paper for the Montana Environmental Quality Council

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November 19, 2001

1. Historical development of transmission in Montana

The transmission network in Montana developed over time as it did in most places, as a result of local decisions in response to the growth of demand for power and decisions on where to build generation. The earliest power plants in Montana were small hydro generators and coal fired steam plants serving local needs for lighting, power and streetcars. The earliest long distance transmission lines were built from the Madison plant to Butte and from Great Falls to Anaconda. The latter was at the time of construction the longest high voltage (100 kV) transmission line in the country.

As the MPC system, and coop loads dependent on MPC's system for delivery grew, MPC expanded its network to include 161 kV and ultimately a 230 kV backbone. Long distance interconnections did not develop until World War II. During the war the 161 kV Grace line was built from Anaconda south to Idaho. Later, BPA extended its high voltage system into the Flathead Valley to interconnect with Hungry Horse dam and to serve the aluminum plant at Columbia Falls.

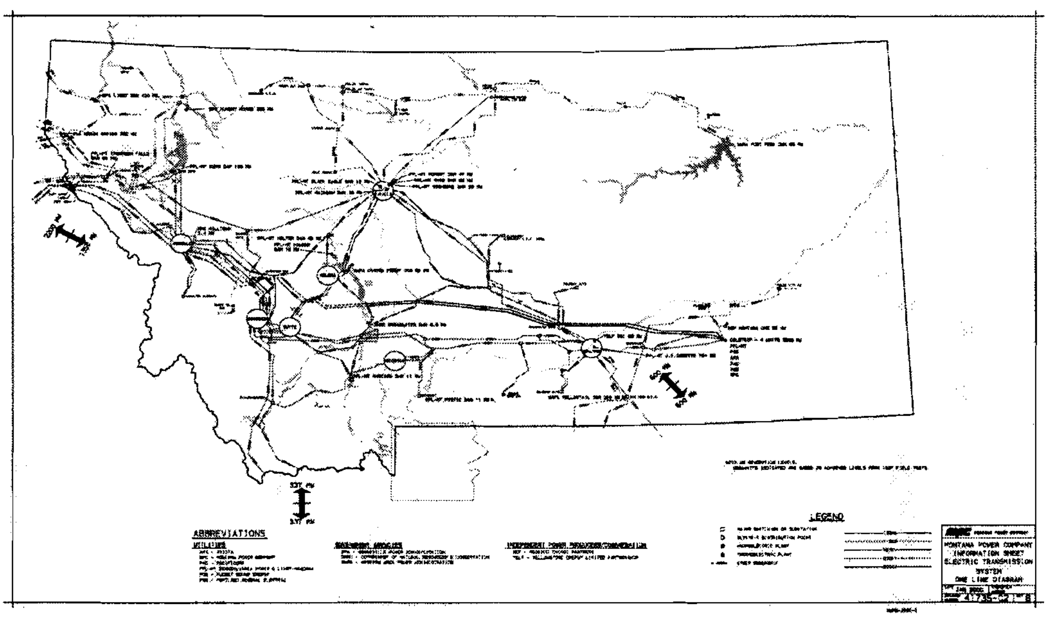

Figure 1. The Western Montana Transmission Network

Montana's strongest interconnections with other regions now are: the Colstrip 500 kV line which connects as far as Spokane and then into the BPA northwest grid; the BPA 230 kV lines heading west from Hot Springs; PacifiCorp's interconnection from Yellowtail south to Wyoming; WAPA's DC tie to the east at Miles City; and the AMPS line running south from Anaconda parallel to the Grace line to Idaho.

As U.S. and Canadian utilities have grown and increasingly relied on each other for support and reliability, the North American transmission network has developed into two major interconnected grids, divided roughly along a line that runs through eastern Montana south to west Texas. The western United States is a single, interconnected and synchronous electric system. Most of the eastern United States is a single, interconnected and synchronous electric system. Texas and Quebec are exceptions; Texas is considered a separate interconnection with its own reliability council, ERCOT.

The Interconnections are not synchronous with each other, and only weakly tied to each other with AC/DC/AC converter stations. One such station is located at Miles City. It is capable of transferring up to 200 MW in either direction. Depending on transmission constraints, a limited amount of additional power can be moved from one grid to the other by shifting units at Fort Peck Dam. By contrast, the peak load in Montana is around 2500 MW.

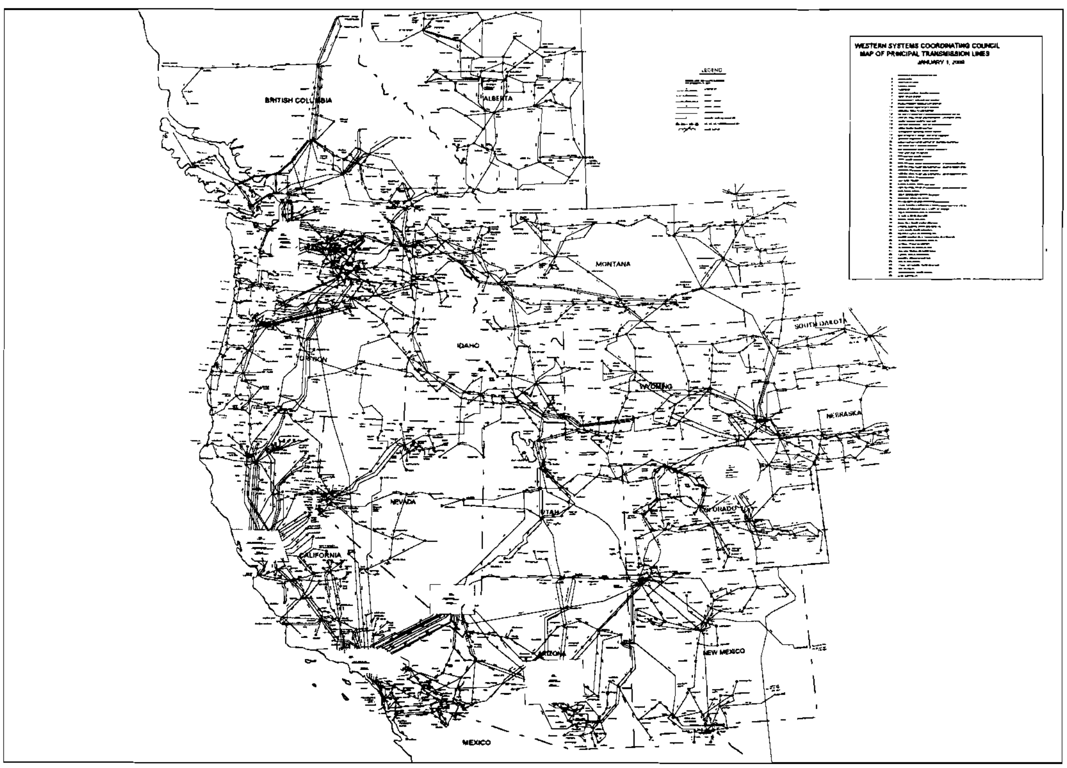

Figure 2. The Western Interconnection transmission network

There are currently 3 DC converter stations between the western and eastern grids with a combined capacity of 510 MW. Three more are planned or under construction at Lamar, in eastern Colorado , Rapid City, and Miles City. There are also two converter stations with a combined capacity of 420 MW connecting the Western Interconnection with ERCOT. The peak load of the western interconnection, by comparison, was around 131,000 MW in 2000.

Most of Montana is integrally tied into the Western electrical grid ("Western Interconnection"). However the easternmost part of the state, with around 5 percent of total Montana load, is part of the Eastern Interconnection and receives its power from generators in that grid.

2. How the transmission system works.

There are big differences between the way the transmission system operates and is managed physically, and the way it is operated commercially. The flows of power on the transmission network follow certain physical laws. Transactions to ship power across the grid follow a different and not fully compatible set of rules.

Physical operation: The transmission grid is sometimes described as an interstate highway system for electricity, but the flow of power on a grid differs in very significant ways from the flow of most other physical commodities. First, when power is sent from one point to a distant location on the transmission grid, the power will flow over all connected paths on the network. It will distribute itself so that the greatest portions flow over the paths of lowest resistance ("impedance," in alternating current circuits), and it generally cannot be constrained to any particular path or contract path. For example, power sent from Colstrip to Los Angeles will flow mostly west to Oregon and Washington and then south to California. But portions will flow south via Garrison into Idaho, and even southeast from Colstrip into Wyoming and then south to Arizona before continuing to Los Angeles.

A second way in which power flows differently than other commodities is that flows in opposite directions net against each other. If traffic is congested in both directions on an interstate highway it will come to a halt in all lanes and not a single additional vehicle will be able to enter the flow. By contrast, if 100 MW were shipped westbound on a transmission line from point A to point B, and 25 MW were sent simultaneously eastbound from point B to point A, the actual measured flow on the line would be 75 MW in a westbound direction. If power were shipped simultaneously in opposite directions at the full capacity of a transmission line, the net flow would be zero, and additional power could flow in either direction up to the full capacity of the line.

As a consequence of the above factors, the actual flows on the network are the net result of all generators and all loads on the network. In any real transmission network there are many generators located at hundreds of different points on the network, and many loads of varying sizes located at thousands of different locations. Because of netting, regardless of where power is sent or from where it is purchased, path loadings will depend only on the amounts and locations of electric generation and load.

Management of the grid. In contrast with the physical reality of the transmission network, management of transmission flows has historically been by use of a "contract path" fiction: A transaction shipping power between two points will be allowed if space has been purchased on any path connecting the two points, from the utilities owning the wires (or the rights to use those wires, if they are transferable) along that path. Transactions are deemed to flow on the contract path. Portions that flow on other paths are termed "inadvertent flows" or "unscheduled flows."

For example, power sent from Colstrip to the West Coast uses a contract path along the 500 kV lines through Garrison and Taft, then across the West of Hatwai path into western Washington and Oregon. However somewhere between 15 and 20 percent of the power actually flows south across two other paths, the Yellowtail-South path and the Montana-Idaho path south from Anaconda.

The topology of the western grid is such that major inadvertent flows occur around the entire Interconnection. Power sent from the Northwest to California flows in part clockwise through Utah and Colorado into New Mexico and Arizona and then west to California. Conversely, a portion of power sent from Arizona to California flows counterclockwise through Utah, Montana and Idaho, then west to Washington and Oregon, and then south into California. These major inadvertent flows are called "loop flow." Expensive devices ("phase shifters") have been installed at several locations to control loop flow and to limit its effect on owners of affected portions of the grid.

Owners of rights or contracts on contract paths are allowed to schedule transactions as long as the total schedules do not exceed the path ratings. Scheduling against reverse flows is not allowed, despite their netting properties, because the capacity created by reverse schedules is not deemed to be firm.

Inadvertent flows may interfere with the ability of path owners to make full use of their rights. The WSCC Unscheduled Flow Reduction Procedure requires utilities whose wires are affected by inadvertent flows to first accept flows up to the greater of 50 MW or 5 percent of the path rating by curtailing their own schedules. If further reductions are necessary the path owners can request the operation of phase shifters (devices that block loop flows) or curtailments of schedules across other paths that affect their ability to use their own path. Phase shifters are limited to operation no more than 2000 hours per year.

The shift to management of the grid by an RTO (discussed below) will do away with the use of the contract path, and with it, the necessity for special management of inadvertent flows.

If the scheduled flows do not exhaust the path rating, the unused capacity may be released as non-firm transmission capacity. This capacity cannot be purchased in advance; it can be scheduled only at the last hour. Owners of capacity who do not plan to use it could release it earlier, but often are reluctant to do so because of their own needs for flexibility or a desire to withhold access by competitors to their markets.

3. Grid Capacity and Reliability

The amount of power a transmission line can carry is limited by several factors. A major factor is its thermal limit. When flows get high enough the wire heats up and stretches, eventually sagging too close to the ground and arcing. Other factors relate to inductive and capacitative characteristics of AC networks. But the most important factor, indeed the limiting factor, is reliability. The transmission network is composed of thousands of elements that are subject to random failure, caused by such things as lightning strikes, ice burdens, pole collapse, trees falling on conductors and vandalism. Since customers value reliability and can be greatly harmed by loss of power, reliability of the grid is assured by building redundancy into it. It is designed to be able to withstand the loss of key elements and still provide uninterrupted service to customers. Service is provided by the network, not by individual transmission lines. Reliability concerns limit the amount of power that can be carried to the amount that can be served with key elements out of service.

Two examples will show how this applies. Within Montana Power's service area the reliability of the transmission system is evaluated by computer simulation of the network at future load and generation levels, taking individual elements out of service and determining whether all loads can be served with voltage levels and frequencies within acceptable ranges. If acceptable limits are violated, the network must be expanded and strengthened. Typically this means adding transmission lines or rebuilding existing ones to higher capacities. Identical procedures are used by other utilities and by regional transmission and reliability organizations.

The second example relates to major transmission paths used to serve distant load or to make wholesale transactions. Paths are bundles of related transmission lines that carry power between the same general areas. Most major paths are rated in terms of the amount of power they can carry, based on their strongest element being unavailable. (In some cases the reliability criteria require the ability to withstand two or more elements out of service.) For example, the Colstrip 500 KV lines are a double circuit line, but they cannot reliably carry power up to their thermal limit because one circuit may be out of service. Recently there has been a move by the WSCC, the Western Interconnection reliability council, to require the paths of which the Colstrip lines are a part to model both circuits out of service, because of the possibility of a tower collapse.

The paths through Montana toward the west have been rated and are limited generally to 2200 MW east to west. The West of Hatwai path, which is comprised of a number of related lines west of the Spokane area, is rated at 2800 MW.

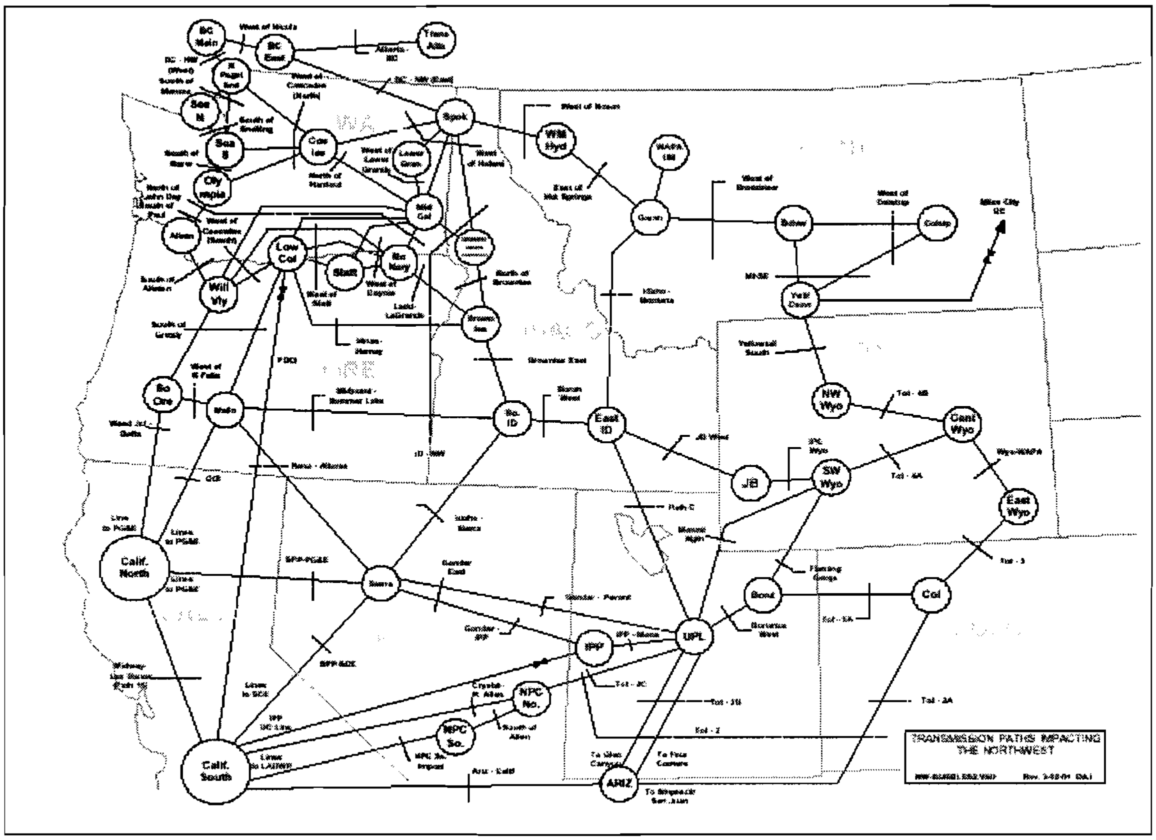

Figure 3. Rated Paths on the Transmission Network

4. Ownership and Rights to Use the Transmission System

Rights to use the transmission system are generally held by the owners or by holders of long-term contract rights. Rights to use rated paths have been allocated among the owners of the transmission lines that comprise the paths. In addition the owners have committed to a variety of contractual arrangements to ship power for other parties. Scheduled power flows are not allowed to exceed the path ratings.

FERC Order 888, issued on March 4, 1997, required that transmission owners functionally separate their transmission operations to make them independent of their power marketing operations. They must allow other parties to use their systems under the same terms and conditions as their own marketing arms. They must maintain a web site ("Open Access Same Time Information System," or OASIS) on which available capacity is posted.

Available transmission capacity (ATC) is calculated by subtracting committed uses and existing contracts from total rated transfer capacity. Little or no ATC is available on most major rated paths, including those leading west from Montana to the West Coast. The rights to use the capacity are fully allocated and closely held. None is available for purchase by new market entrants.

These existing rights – and ATC, if any existed – are rights to transfer power on a firm basis every hour of the year. The owners of the rights on rated paths may or may not actually schedule power in every hour, and when they don't, the space they are not using may be available on a non-firm basis. In fact, the paths are fully scheduled for only a small portion of the year, and non-firm space is almost always available. For example, according to MPC, in the 12 months through September, 2001, the West of Hatwai path was fully scheduled or over scheduled about 8 percent of the time. The remainder of the time, 92 percent of the year, non-firm access was available.

However, non-firm access cannot be scheduled in advance or guaranteed. It is a workable way to market excess power for existing generators, and may be a reasonable way to make firm power transactions if backup arrangements can be made to cover the contracts in the event the non-firm space turns out to be unavailable. However it may be difficult to finance new generation if it cannot be shown with certainty that the power can be moved to market.

5. Congestion

A transmission path may be described as congested if no rights to use it are for sale. Alternately, congestion could mean that it is fully scheduled and no firm space is available. Or it could mean that the path is fully loaded. These are three different concepts.

By the first definition, the paths west of Montana are congested – no rights are available and no ATC is offered for sale on the OASIS.

By the second definition, the paths are congested a few hours of the year - the rights holders fully use their scheduling rights a fraction of the time, and the rest of the time they use only portions of their rights. In the past year, the West of Hatwai path was congested under this definition 8 percent of the time.

The third definition is based on actual loadings. Actual loadings are different than scheduled flows because of the difference between the physics and the management of the grid – schedules are contract-path-based, and actual loadings are net-flow-based. Actual flows on the paths west of Montana are almost always below scheduled flows, because of the net impacts of inadvertent flows and loop flows. Actual hourly loadings on the West of Hatwai path are posted on BPA's OASIS site. For the first eight months of this year, highest actual loadings were around 90 percent of the path capacity for only a few hours. For most hours the path was not heavily loaded. By the third definition, the lines currently are never congested – even when the lines are fully scheduled, the net flows are below path ratings.

West of Hatwai Jan-August 2001 E-W Cumulative Loading Curve

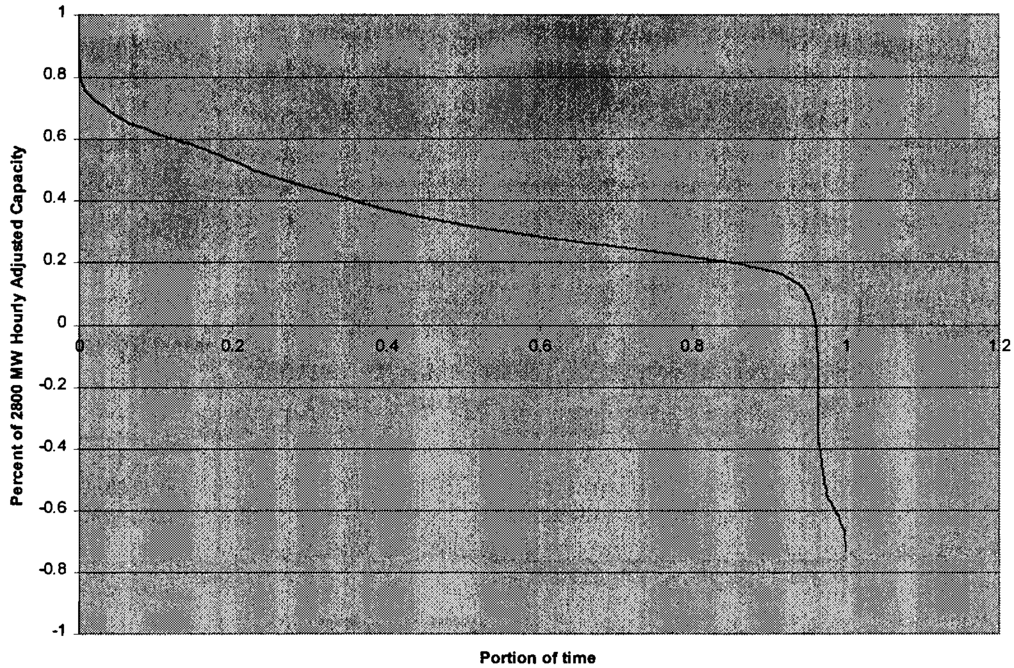

Figure 4. West of Hatwai Path Cumulative Loading Curve Jan-Aug 2001
(Negative flows mean power was flowing from west to east)

6. Grid Management By RTO West.

Discussions have been underway for several years among the transmission owners and other stakeholders in the Northwest to have an independent body take over operation and control of access for the transmission system. This was partly out of a recognition by the transmission owners that proof of independence, as required by FERC Order 888, would become an increasingly difficult burden, and partly out of anticipation that FERC would ultimately move to order such a transfer. Initial discussion revolved around IndeGO, a proposed independent system operator that would lease and operate the wires. The IndeGO discussions ultimately foundered on cost-shifting concerns, but after FERC issued Order 2000 the discussions revived, focusing now on a Regional Transmission Organization (RTO) that would own as well as operate the system.

Assumption of responsibility for grid management by RTO West is important because for the first time it would provide for a market-driven means of managing congestion. The current fixed assignment of rights to use the grid prevents non-incumbents from making use of unused capacity, and even hinders their ability to bid for it. The RTO would allow all parties to signal their willingness to pay for access and to make efficient use of the grid. In addition the RTO management would result in congestion price signals that would allow economic decisions on location of new generation and on expansion of capacity on congested transmission paths.

7. Major Issues of Transmission

There are a number of issues affecting the transmission system and the need for and ability to complete new transmission projects. Some of these are discussed below.

Availability of existing capacity. A considerable amount of existing capacity is not available for use because it is held off the table for reliability reasons when paths are rated. (See discussion of reliability issues, below.) Significant additional capacity is often withheld by owners because of uncertainty, need for flexibility, and in some cases, to protect their markets. Uncertainty affects the transmission needs of utilities because they don't know in advance what hourly loads will be or which generating units may be unavailable.

Need for flexibility affects transmission needs because utilities want the right to purchase capacity to serve their loads from the cheapest source. When RTO West tried to convert existing contract rights into flow based rights the claims greatly exceeded available capacity. This was largely due to utilities that had a right, for example, to move 100 MW on any of several paths, claiming a simultaneous right of 100 MW on all of them.

Complaints of withholding of capacity for market protection are a violation of Order 888. Withholding has been a problem since the order was issued, with a number of utilities being cited and fined by FERC for violations. The failure of Order 888 to result in open and comparable access was a major reason for FERC Order 2000 which requires utilities to form RTOs.

Reliability Criteria. Reliability is an issue because the criteria governing the setting of path capacity and the operation and expansion of the transmission system relate only vaguely to economics – they do not reflect very well the probability or the consequences of the events being protected against. Since the system is quite reliable as currently built and operated, at the margin reliability generally involves very low probability events that may, depending on when they occur, have high costs. Further, the criteria apply everywhere on the transmission grid despite the fact that in some areas and on some paths the consequences may be minimal while in other areas and other paths the same type of event may have large consequences. For example, Path 15 in central California, where a line outage can result in cascading failure and impact many millions of people, should probably be operated more stringently than parts of the transmission grid where an outage might cause a generating unit to trip off , but not affect any load.

Reliability criteria for the Western Interconnection are set by the Western Systems Coordinating Council (WSCC), which is part of the National Electric Reliabity Council (NERC). WSCC is largely a creature of the transmission owning utilities. WSCC has generally opposed suggestions to subject the reliability criteria to cost-benefit considerations.

WSCC may tighten reliability standards to increase reliability without regard to the impact of its decisions. For example WSCC recently set a 1000 foot separation rule for new transmission lines, precluding the use of existing corridors and rights of way for siting new lines adjacent to existing ones. In areas where siting opportunities are limited such a move may greatly increase the difficulty of building additional capacity.

FERC recently approved a merger of WSCC with several other transmission organizations into a new organization to be called the Western Electricity Coordinating Council (WECC) which will have much broader representation on its board and will have stakeholder advisory committees.

Hours of Congestion As discussed out above, the congested portions of the transmission grid tend to be fully or heavily scheduled and loaded only a few hours to a few hundred hours of the year. The rest of the time there is excess capacity available, although it is a challenge to make use of it on a firm basis. Expanding capacity is expensive and difficult. Yet it is the preferred method of gaining access for additional transactions and additional flows. If the costs could be assigned to the congested hours only it is very likely cheaper alternatives to new construction would be found. For example, some current users with relatively low valued transactions or with ready alternatives might be willing, at some price, to sell their rights to new users.

Difficulty of Siting New Transmission High voltage transmission lines can be difficult and contentious to site, especially in forested, mountainous or populous areas. For example, the Colstrip double circuit 500 kV lines were relatively easy to site in eastern Montana where they traversed rolling agricultural and grazing land. Siting in western Montana was a different story, particularly in the areas of Boulder, Rock Creek and Missoula. The resulting route had to stay away from the interstate highway corridor, instead opening new corridors through forested areas with issues of impacts to elk security areas and increased access for ORVs. Lengthy detours around Boulder and Missoula added considerably to the cost of the line. Rural growth and residential construction in western Montana in the 15 years since the Colstrip lines were sited, combined with the already limited siting opportunities due to wilderness areas and Glacier National Park, can be expected to make siting challenges more likely for additional construction.

Further, the recent proposed changes in WSCC criteria, mentioned above, have increased the likelihood that new lines would have to open additional corridors instead of making use of existing corridors.

Cost High voltage transmission lines are expensive to build. A typical single-circuit 500 kV line may run over $1 million per mile. A double-circuit 500 kV line may cost around $1.5 to $1.75 million per mile. 500 kV substations cost around $50 million each, depending on the complexity caused by their location on the network. If series compensation is required, 500 kV substations may cost up to $100 million. 230 kV lines are somewhat cheaper – about half the cost per mile of 500 kV lines, and substation costs run around $25-30 million each. DC lines are a bit cheaper but the equipment required to convert alternating current to direct current and back is extremely expensive, so this technology is generally used only for very long distance transmission with no intermediate interconnections. There are only two DC lines in the Western Interconnection – the Pacific DC Intertie, from Celilo in southern Oregon to Sylmar near Los Angeles, and the IPP line from the Intermountain Power Project generating station in Utah to the Adelanto substation, also near Los Angeles. Neither line has any intermediate connections.

Who Pays? Finally, a major issue in getting new transmission capacity investments is the question of who pays for them and who benefits from them.

The primary beneficiaries of new transmission capacity are those who were previously unable to gain access but who now can make firm transactions that make new generation feasible. Consumers will also benefit by having access to cheaper generation, although load-serving entities generally hold rights to transmission and can use them to access generation now.

The question of who pays is important because it affects the difficulty of determining whether and which transmission projects are worth building. If the beneficiaries pay the costs and bear the risks of new transmission investments many of these questions are off the table. The users of proposed new generation are the ones best positioned to assess its value, and if they are bearing the costs and risks then siting becomes relatively simple. However, if the costs and risks are socialized and borne by ratepayers or taxpayers, issues of need and economic feasibility become both more important and more difficult to assess.

The key to getting transmission built in the near term to accommodate new generating plants in Montana that require access to West Coast markets may be subscription, where interested parties commit to use and financing of shares of the project. With a subscription process the generating projects that are reasonably certain of marketability and feasibility would get together to propose to build and finance the transmission needed to service them. This was the process used for the 500 kV lines by the five utilities that built Colstrip 3 and 4. It is also commonly used in the construction of natural gas pipelines, such as the recently completed Alliance Pipeline from Alberta to Chicago.