# Beneficiaries-pay in USA

## Discussions on implementation of beneficiaries-pay cost allocation for transmission investment

Joint report: Electricity Authority, Commerce Commission and Transpower

20 June 2018

# Executive summary

In order to inform the transmission pricing methodology (TPM) review, the Electricity Authority (Authority) Board has directed staff to investigate the use, overseas, of quantitative models to identify beneficiaries and determine benefits of transmission investments for allocating investment costs through a beneficiaries-pay charge. The Board was aware that some Independent System Operators (ISOs) and Regional Transmission Operators (RTOs) in the United States (US) have adopted this approach.

In March 2018 a group from New Zealand (NZ) visited the US for the purpose of learning more about the beneficiaries-pay approach used by a number of ISOs and RTOs to allocate transmission investment costs and better understand the US experience. The group included representatives from the Authority Board and staff, Transpower and the Commerce Commission. Transpower was invited because of its role in developing and applying the TPM in accordance with TPM guidelines promulgated by the Authority. The Commerce Commission was invited because of its role in approving transmission investments. Each of the attendees has contributed to this report based on their recollections of the discussions in the US.

The group met with representatives of New York ISO (NYISO), the New York Department of Public Service (DPS), the Midcontinent ISO (MISO), PJM Interconnection (PJM) and with Professor William Hogan.

## Caveats

The meetings in the US were with people with varying seniority and roles in their respective organisations. Cost allocation practitioners were asked for their views on the strengths and weaknesses of their own approach. In some of their comments they provided their own personal views, and in other cases the views provided were effectively the formal positions of their organisations. It is difficult to separate these types of comments from each other, so this report contains a mixture of both types.

One consistent theme of the discussions related to how the cost allocation approach under discussion had been received by stakeholders. While the people we spoke to provided their own views on this question, we did not speak to or hear directly from these stakeholders.

## Drivers for beneficiaries-pay in the US

Beneficiaries-pays methods in the US were introduced in response to the Federal Energy Regulatory Commission (FERC) issuing Order 1000 in 2011, which required the adoption of beneficiaries-pay methods for allocation of costs of regulated transmission investments. Key issues with historic cost allocation methods included allocation between different transmission owners (transmission owners are the regulated transmission customers of the ISOs/RTOs), including inter-state issues.

Historically, there was no means for a transmission owner to recover costs from beneficiaries outside their transmission footprint, regardless of whether beneficiaries were principally in other transmission owners' regions.  This resulted in transmission investments that were economic not being able to proceed. Rather, generation local to load (principally gas, coal and nuclear) was built ahead of economic transmission.

Following FERC's Order 1000, beneficiaries-pay approaches have been implemented in a number of jurisdictions in the US, including each of the ISOs / RTOs visited by the group.

## What we heard

Below are some high-level take-outs from what we heard:

- Each of the three ISOs / RTOs we met operates a beneficiaries-pay approach which is used to allocate the costs of new, higher value and/or voltage regulated transmission investments in the economic category.
- The costs of investments in other categories tend to be allocated using simpler methods, and often allocated to the zone in which they were built and/or socialised using postage-stamp type methods including total volume and peak usage.
- None of the three ISOs / RTOs applies a beneficiaries-pay approach to recover the costs of existing assets. Historic costs are allocated to the zone in which they were built and then socialised, typically using postage-stamp type methods including total volume and peak usage.
- A new investment is assigned by need and value or capacity into a category, such as reliability, economic (or market efficiency) or public policy, each of which has different rules for cost allocation and investment approval. Investment approval and cost allocation processes are linked and based on the same or similar analytical assessments.
- "Market efficiency" (economic investment) projects have been approved with costs allocated on a beneficiaries-pay basis: around 50 projects by PJM and 5 by MISO. NYISO has yet to commit a project, but has two "public policy" investments in process with recovery expected to be 75% by beneficiaries-pay and 25% socialised.
- For the economic category, costs are typically allocated between large zones based on the economic benefits each zone is forecast to receive from the investment: NYISO considers 11 zones across NY state (20 million people), PJM 25 zones across 14 states (65 million people) and MISO 11 zones across 15 US states and 1 Canadian province (42 million end-use consumers). Within zones costs are socialised using postage stamp methods including total volume and peak usage.
- Forecast benefits of investments in the economic (or market efficiency) category are modelled using comprehensive and detailed system planning software models. The modelling methods are resource-intensive and time-consuming. Questions were raised by the person we spoke to from MISO whether the complexity and detail introduces false precision.
- We were told the beneficiaries-pay approach is accepted in principle by most reasonable stakeholders and there have been relatively few disagreements resulting in legal challenge. Where challenge does arise, it tends to be where one or a very small number of parties were allocated all, or almost all, the costs of a high-value new investment.
- The ISOs / RTOs seek stakeholder acceptance by working collaboratively with stakeholders to establish transparent long-term transmission plans including demand forecast inputs or "futures". This planning is undertaken periodically, every two to three years, or annually (MISO), and forms the underlying input for assessment of future new investment proposals and cost allocations.
- Efficiency benefits are realised through transparency with stakeholders: they know what costs they will be allocated through the beneficiaries-pay approach and so are motivated to involve themselves in ensuring the right investment decision is made.

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# 1 Introduction

1.1 In order to inform the TPM review, the Authority Board directed staff to investigate the use, overseas, of quantitative models to identify beneficiaries and determine benefits of transmission investments for allocating investment costs through a beneficiaries-pay charge. The Board was aware that some ISOs and RTOs in the US have adopted this approach.

1.2 In March 2018 a group from NZ visited the US for the purpose of learning more about the beneficiaries-pay approach used by a number of ISOs / RTOs to allocate transmission investment costs and better understand the US experience. The group included representatives from the Authority Board and staff, Transpower and the Commerce Commission. Transpower was invited because of its role in developing and applying the TPM in accordance with TPM guidelines promulgated by the Authority. The Commerce Commission was invited because of its role in approving transmission investments.

1.3 The group met with representatives of:

(a) the New York ISO (NYISO)

(b) the New York Department of Public Service (DPS)

(c) the Midcontinent ISO (MISO)

(d) PJM Interconnection (PJM)

(e) and also with Professor William Hogan.

## Objectives

1.4 Our objectives for the trip, and for each meeting were to:

(a) learn about applications of a beneficiaries-pay approach to allocate the costs of new regulated transmission investments, including any challenges in applying charges, and the responses from their stakeholders;

(b) understand the practicability and implementability of the method; and

(c) make contacts with practitioners who may be helpful if we develop a beneficiaries-pay methodology in NZ.

## NZ attendees

1.5 The attendees from NZ (at all meetings in the US) were as follows:

(a) Allan Dawson, Board member, Electricity Authority

(b) Nick Russ, General Manager, Regulation, Commerce Commission

(c) Rebecca Osborne, Regulatory Affairs and Pricing Manager, Transpower.

(d) Tim Sparks, Principal Adviser, Electricity Authority.

1.6 Each of these attendees has contributed to this report based on their recollections of the discussions in the US.

## US institutional background

1.7 A number of different organisations have responsibilities relevant to the allocation of electricity transmission costs in US jurisdictions.

1.8 FERC is the federal agency that oversees the transmission, pricing and wholesale sale of electricity in the US, particularly where there are implications for interstate commerce. (It also has responsibilities relating to oil and gas.) FERC has various consumer protection objectives, including ensuring that electricity rates are just and reasonable.

1.9 There are also energy regulatory agencies at the state level. State regulators have responsibilities regarding approval of investments for cost recovery from electricity consumers and setting consumer rates.

1.10 An ISO is an independent electricity system operator which coordinates, controls and monitors a transmission grid. An ISO's system is sometimes limited to a single US State, and sometimes encompasses multiple states. RTOs typically perform the same functions as ISOs, but cover a larger geographic area. The creation of RTOs was initiated by FERC in response to challenges associated with the operation of multiple interconnected independent utilities.[1] There are ten such organisations (ISOs / RTOs) in North America.

1.11 ISOs / RTOs are responsible for transmission planning within their system. Both the determination of any new transmission investment that is required and the allocation of the costs of such investments occur within the context of the transmission planning process.

1.12 ISOs / RTOs are required to follow FERC orders relating to transmission and pricing. Beneficiaries-pays methods in the US were introduced largely in response to the FERC issuing Order 1000 in 2011, which set out guidance for cost allocation for new regulated transmission investments, including:

(a) costs to be allocated "roughly commensurate" with estimated benefits

(b) those who do not benefit from transmission do not have to pay for it

(c) benefit-to-cost thresholds must not exclude projects with significant net benefits

(d) no allocation of costs outside a region unless the other region agrees

(e) cost allocation methods and identification of beneficiaries must be transparent

(f) different allocation methods could apply to different types of transmission facilities.

1.13 Beneficiaries-pay approaches have been implemented in a number of jurisdictions in the US, including each of the ISOs visited by the group. These approaches apply only to new investments (as FERC order 1000 does not apply to historical investments). Stakeholders are able to challenge ISOs / RTOs' cost allocations by making an application to FERC that the allocation was not "just and reasonable".

1.14 Key issues with historic cost allocation methods in the US include allocation between different transmission network owners, and inter-state issues. Historically, there was no means for a transmission owner to recover costs from beneficiaries outside their transmission footprint, regardless of whether beneficiaries were principally in other transmission owners' regions. This resulted in transmission investments that were economic not being able to proceed. Rather, generation local to load (principally gas, coal and nuclear) was built ahead of economic transmission.

[1] FERC Order No. 2000, issued on December 20, 1999.

# 2 NYISO

## Background

### NYISO

2.1 NYISO is a not-for-profit corporation responsible for administering New York State’s bulk electricity grid and wholesale electricity markets (serving 20 million people), and conducting long-term planning for the state’s power system. NYISO has responsibilities for decision-making on new transmission investment proposals and acts as the clearing house for the state energy and ancillaries markets, and transmission with respect to inter-state connections. The power system in NY state “always” flows from upstate to large load centres downstate, including New York City.

2.2 In response to FERC Order 1000, NYISO developed a beneficiaries-pay approach to cost allocation for new transmission investments. Beneficiaries are defined in different ways depending on whether a project is made for economic reasons, or for purposes of reliability or public policy. Under this mechanism NYISO will act as the clearing house for cost recovery by owners of new regulated transmission investments.

2.3 No regulated transmission investments have been committed or built since the introduction of NYISO's beneficiaries-pay approach. However, two investment proposals are progressing as "public policy" investments, to enable renewable generation from upstate and Canada to supply the large load centres downstate, including New York City (cost allocation for one has been approved).

2.4 The state Government makes the decision to proceed with public policy investments based on cost-benefit assessments that allow consideration of less tangible or monetised benefits including emissions reduction benefits.

### New York Department of Public Service

2.5 The New York Department of Public Service (DPS) regulates and oversees the electric, gas, water, and telecommunication industries in New York. The part of DPS that does this is called the Public Service Commission (PSC). (The PSC is within the DPS, and the chairman of the PSC is the CEO of the DPS.) The PSC sets rates and ensures New York's regulated utilities provide safe, reliable and adequate services.

2.6 The DPS participated in developing NYISO's beneficiaries-pay approach to cost allocation for transmission investments, and is an informed observer of NYISO's approach since the system was introduced. The DPS also has a role in determining the cost allocation approach for public policy projects.

## Attendees

2.7 On 27 March 2018 we met with a number of people at NYISO including the following:

(a) Bradley C. Jones, President and CEO

(b) Zach Smith, Vice President, System & Resource Planning

(c) Yachi Lin, Senior Manager, Transmission Planning

(d) Tim Duffy, Manager, Economic Planning

(e) Ray Stalter, Director, Regulatory Affairs

(f) Michael Jamison, Regulatory Affairs.

2.8 On 27 March 2018 we met with the following people at the DPS:

(a) Warren Myers, Director, Office of Market and Regulatory Economics

(b) Allen Michaels, Assistant Counsel, NYISO and Wholesale

(c) Thomas Paynter, Economist

(d) Jerry Ancona, Power Transmission Planner.

## What we heard

2.9 Below are the main points we heard in our discussions at NYISO and DPS. Unless otherwise indicated, the points were made by NYISO staff. Where a point originates from the discussion at DPS, this is indicated.

### Background to adoption of beneficiaries-pay approach

2.10 The grid backbone in New York state has for some time needed to be strengthened in order to increase potential transmission capacity from upstate (northern) New York, where most of the (renewable) generation potential is, into New York city. This upgrade project would cross multiple transmission network areas. The historic cost recovery methodology would have allocated the costs of transmission upgrades to the customers in the upstate transmission areas rather than the beneficiaries of the project (located downstate including New York city). This cost recovery methodology was perceived as a barrier to investment occurring, and beneficiaries-pay was seen as a potential solution: DPS said that "you won't get anything built unless you have beneficiaries-pay."

2.11 However, no transmission investment has yet been built under the beneficiaries-pay approach, reportedly due to considerable hurdles within the design of the cost-benefit assessment for economic transmission investments, including bias towards generation solutions. Instead, two projects associated with grid strengthening are proceeding via the public policy category route.

### Cost allocation for the different categories of regulated transmission investment

2.12 Costs for new regulated investments are allocated based on different rules for each of the three investment categories:

(a) For the reliability category, beneficiaries of investments are determined and costs are allocated based on calculating the amount of load that would be shed (without the investment) and who would lose it.

(b) For the economic category, beneficiaries of investments are determined and costs are allocated based on decreases in load's payments for energy as a result of a transmission project. The models estimate or forecast changes in locational marginal prices (LMPs) resulting from an investment for each of 11 cost allocation zones over the first ten years that the investment will be in service. For example, New York City is one of the 11 cost allocation zones, and Long Island is another.

(c) For the public policy category, the PSC specifies the allocation process. If there is no specification, the method defaults to a state-wide load ratio share. For public policy projects considered to date, the PSC has specified a portion of the costs to be shared across the state, with the balance allocated in accordance with NYISO's beneficiaries-pay method for economic investments.

2.13 NYISO carries out any modelling of benefits that is required for cost allocation purposes. NYISO consults with stakeholders before finalising its view of the appropriate cost allocation.

2.14 Costs of historic investments are recovered based on the volume of energy purchases, either socialised within one of the eight incumbent transmission owners' network area or socialised state-wide. At one time there was a proposal to socialise costs of all existing assets on a state-wide basis, but it was decided not to go down this path because it would have resulted in significant wealth transfers and concerns about equity and fairness. For example, we heard that customers in Buffalo (upstate) didn't want to pay for the high embedded cost of lines in Manhattan.

### Modelling and stakeholder engagement

2.15 Modelling of benefits for the economic category (and, where required, for the public policy category) is carried out using GE's Multi Area Production Simulation (MAPS) production cost modelling software. Forecasts are prepared for the New York electricity system, taking into account flows to and from other interconnected systems, going out at least 10 years. This year the forecast was extended out to 20 years.

2.16 Key inputs include fuel prices, load forecasts and system topology (including expected transmission and generation upgrades). NYISO works with transmission owners to obtain their data (e.g. demand projections). The aim is to collect all the data in one place, as a foundation to inform the analysis. Data on peak load and energy consumption is published on an annual basis by NYISO.

2.17 The costs of new regulated transmission investments are recovered from load only. Generators only pay for their connection and any investments they cause by connecting, including to enable them to access capacity markets.

2.18 Professor Hogan said that NYISO's approach to beneficiary-pays is "terrific", excepting they should charge benefitting generators as well as benefitting load DPS said that the reason generators were not determined to be beneficiaries was that "they would just pass charges on to load anyway."

2.19 NYISO and DPS consider NYISO's beneficiaries-pay modelling methodology is accepted in principle by most stakeholders. (DPS said that – while there's no such thing as pleasing all stakeholders – most reasonable stakeholders think the method seems reasonable.) Challenge from stakeholders does arise, typically directed at the level of detail (e.g. model inputs). (We didn't hear the reasons why challenge is typically directed at the level of detail. It is possible that this is because the method has already been determined so there isn't opportunity to challenge it beyond model inputs.)

2.20 NYISO considers they have achieved stakeholder acceptance and did so through an open and transparent collaborative planning process. This planning process takes seven to nine months and is run every two years. Stakeholders are engaged throughout the process.

2.21 NYISO's planning process proceeds through a multi-stage "gating" process (ie, approval is required at each level before it can progress):

(a) Initially: lower level working groups e.g. Electric System Planning Working Group (ESPWG)

(b) next level up: operating committee

(c) finally: management committee

(d) (potentially) appeal to NYISO Board.[2]

2.22 NYISO staff present the forecasts and network topology that they are planning to use in the modelling to the ESPWG, which includes representatives of stakeholders (including generators, load-serving entities (i.e. distributors), transmission owners, the City of New York and the association of community-owned utilities). Typically, there is good engagement from stakeholders in that process.

2.23 At the lower level working group (ESPWG) there is a vote before a matter goes further. According to DPS, this governance structure benefits incumbent generators, as “if end users want anything done, generators can block them.”

2.24 The planning process results in a single, central “base case” forecast of demand and generation and transmission developments. The base case is the case considered to be most likely; it is not based on a probabilistic weighted average of various possible scenarios. The base case is subsequently used as the counterfactual (i.e. “without the investment”) scenario for both cost-benefit assessment (in the case of investments in the economic category – discussed below) and beneficiaries-pay cost allocation.

2.25 NYISO considers its process is open and collaborative and this has resulted in a database and base case forecast that is well accepted by stakeholders. NYISO believes a level of credibility with stakeholders has developed over time that this is a robust and transparent process and the assumptions are reasonable. This engagement is carried out upfront, when nothing specific is at stake (because there is no transmission investment on the table at that stage). For a specific investment proposal, the base case has been determined well before you get to the more controversial cost allocation process.

### A biased cost-benefit assessment for economic investments

2.26 A key lesson from NYISO was the need for care in determining the counterfactual scenario (i.e., the scenario in which the transmission investment does not take place). NYISO has set strict rules for investments in its “economic” investment category with a deliberate bias against transmission investment. E.g. in the “counterfactual” scenario without the investment, they are required to assume that generation will emerge to solve all reliability problems (which reduces the benefits of the transmission investment). Also, the benefits to be captured in the cost-benefit analysis (CBA) for the economic planning process are not comprehensive: some potential benefits (e.g., capacity and emissions reduction benefits) are not taken into account.

2.27 In order to be approved, investments in the economic category must pass two tests:

(a) First, the investment’s benefits in terms of saved production (i.e. generation) costs must exceed the cost of the investment. Production cost savings are estimated for the purposes of the first test using the same model that is also used to calculate savings in load LMP payments for the purposes of benefits-based cost allocation.

(b) Second, 80% of beneficiaries must vote in favour of the investment.

2.28 To date none of the investments considered in the economic category have passed the first test. So no investment has yet proceeded to the voting stage.

[2] Appeals can also be made to DPS, at least in some categories.

2.29 NYISO and DPS consider one of the main reasons that no economic investment has passed the cost-benefit test is that the economic benefits considered are limited by the approach required to be taken with respect to the counterfactual scenario. The planner is required to assume that the system remains reliable during the next 20 years. If the planner finds a reliability problem, it is required to assume that generation enters and addresses the reliability issue. So the only benefits of the investment that can be taken into account are any additional benefits that would remain after all reliability problems for the next 20 years have already been solved by the entry of new generation.

2.30 Other contributing factors include the following:

(a) only production cost savings can be taken into account as benefits. Other potential benefits such as capacity benefits (resulting from NYISO's capacity market) and emissions reduction benefits cannot be taken into account.

(b) the process requires a focus only on congestion in the identified top three congested paths, and does not allow a focus on congestion in an aggregated "chunk" of the system (which would likely result in greater benefits)

(c) only one central scenario is used to calculate benefits (as opposed to, e.g., a high-renewables scenario – in which more transmission would likely be economic)

(d) according to DPS, the model assumes that all transmission lines are in service; that is, there are no line outages. As a result, its congestion forecast is always low (compared to actual historic levels), which causes the estimated benefits of a transmission investment to be artificially lowered

(e) the costs used in the cost-benefit assessment are relatively high (because the assessment uses generic costs that are sourced from utilities).

2.31 According to NYISO, these rules were set with a deliberate bias against transmission investment. The purpose was to encourage generators to enter and solve congestion problems rather than rely on transmission solutions. This policy has resulted in the entry of generation in downstate New York (where most load is located and most generation is fossil-fuel and nuclear). DPS noted that it was an "intentionally conservative" approach, intended to allow room for competitive models.

2.32 NYISO's rules for recovering and allocating the cost of new regulated transmission investments are specified in its "NYISO OATT" (2119 pages), which has been approved by FERC, and supporting documentation. NYISO has this year initiated a review of the NYISO OATT, with a view to reforms that address the concerns/problems reported above.

### Current examples of beneficiaries-pay cost allocation at NYISO: AC initiative and Western NY upgrade

2.33 NYISO, working with the PSC, has used its beneficiaries-pay methodology to determine cost allocation for a planned public policy transmission investment known as "the AC initiative" (1000MW). The allocation has been confirmed by FERC and is available in a published report.

2.34 NYISO staff consider that a contributing factor in the approval of the cost allocation by PSC and FERC was that NYISO had shared its methodology with stakeholders, so it had already been through a vetting process. The inputs and assumptions had been made very transparent. The collaborative process that had been carried out (described above) had developed the credibility of the method.

2.35 Costs of the AC initiative project will be allocated:

(a) 75% beneficiaries-pay (with benefits determined through the modelling process discussed above). Beneficiaries of the investment were determined by modelling to be (indicatively) 90% downstate and 10% upstate; and

(b) 25% socialised across all NY state load (load ratio share). This represents intangible benefits that are difficult to quantify and allocate, and is the result of a pragmatic compromise: DPS said that most reasonable stakeholders accepted this level of socialisation.

2.36 There was some dispute from beneficiaries over the cost allocation for the AC initiative. Some parties lodged public filings with the PSC challenging aspects of the allocation (for example, the fact that the allocation considers energy benefits but not capacity benefits). Ultimately both the PSC and FERC approved the allocation, and there were no subsequent challenges. The allocation has not been challenged in court.

2.37 Another public policy category investment is in the process of cost allocation: the "Western New York" upgrade project. According to DPS, the Western New York upgrade will also be allocated 75% / 25% in the same way.

2.38 Both projects are yet to have progressed to committed capital projects.

# 3 MISO

## Background

3.1 MISO is an ISO and RTO providing open-access transmission service and monitoring the high-voltage transmission system in the Midwest US and Manitoba, Canada and a southern US region which includes much of Arkansas, Mississippi, and Louisiana. MISO also operates one of the world's largest real-time energy markets covering 15 US states and one Canadian province (42 million end-use consumers).

3.2 MISO employs different charging approaches depending on investment type (i.e., market efficiency,[3] reliability or a combination). Some of the approaches involve beneficiaries-pay arrangements, some are postage stamp, and others are intended to be broad proxies for benefits.

3.3 MISO's beneficiaries-pay approach has been in place about ten years during which time five market efficiency projects have been committed under a beneficiaries-pay mechanism.

## Attendees

3.4 On 28 March 2018 we met with Zheng Zhou, Manager, Economic Studies, North/Central region.

## What we heard

Below are the main points we heard in our discussions with MISO.

### Applications of beneficiaries-pay methodology to date

3.5 MISO has applied its beneficiaries-pay methodology to five investments in the “market efficiency” category (four 345kV projects and a 500kV project), approved between 2009 and 2017, in 2009/10, 2011/12, 2015, 2016 and 2017. Costs are allocated to load-serving entities.

3.6 MISO applies beneficiaries-pay to future investments only (not historical investments).

3.7 In addition to the beneficiaries-pay methodology, MISO also approved 17 investments in a bulk approval in 2011. These investments were in a different category (known as the multi-value project “MVP” approach). These investments were driven by a renewables policy. The costs for these 17 investments were socialised across the whole MISO footprint (via a postage stamp charge based on volume).

### Methodology used to model benefits and allocate costs

3.8 Benefits are modelled in order to A) perform a CBA of the project for approval purposes and B) allocate costs between 11 cost allocation zones. Each cost allocation zone is typically at least the size of a US state. Bigger zones allow beneficiaries to share the risks associated with transmission investments. The benefits modelled are production cost savings (i.e. if a transmission investment allows lower cost generation to be dispatched).

3.9 MISO’s beneficiaries-pay method is demanding in terms of cost and time. Generation production costs are modelled using a model called PROMOD. The model runs hourly

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[3] MISO uses the term “market efficiency” to describe a category of investments equivalent to NYISO’s “economic” category.

economic dispatch across the Eastern Interconnection in North America (which has 60,000 transmission buses, 5,000 generators) for a year. (Note this hourly solve is less time-granular than the system dispatch model, which needs to be solved every five minutes.) MISO models selected years (e.g. five, ten and fifteen years out from the investment commissioning date). The process takes a lot of resources including both scarce specialist person-hours and computer time (the model takes three days to run).

3.10 To deal with uncertainty, MISO models three to five scenarios ("futures") for its load forecast (e.g. baseline, high and low load growth rates) and then debates and determines a weighting or probability for each scenario. The MISO representative considers it may be better to weight each scenario equally and spend more time determining scenario assumptions. In calculating benefits, they take into account contractual positions of wholesale market participants (to the extent they have visibility).

3.11 The project is approved if the benefits exceed the costs by a ratio of 1.25 or more and has benefits across multiple scenarios.

3.12 80% of a project's costs are allocated based on benefit, and the remaining 20% of costs are socialised across the whole MISO footprint (in order to capture broader social benefits). Once the cost allocation has been made between the 11 zones, allocation to utilities within each zone is socialised on the basis of energy volume.

3.13 Once a cost allocation percentage is determined for each cost allocation zone in the MISO footprint, that allocation continues unchanged throughout the period over which costs are recovered.

The MISO representative we spoke to felt that there was a risk of "false precision" with beneficiaries-pay modelling, particularly if the modelling basis is very granular over a long forecast period. The modelling relies on long-term forecasts and scenarios of possible futures for both demand and generation, each of which in itself is very difficult to predict (the only absolute truth about any forecast is that it will be proven wrong). The risk or concern then is to the value of granularity in long-term forecasting (hourly over up to 15 years) that relies on inputs that are inherently inaccurate. One example given was that in MISO's system a large number of (largely coal) generators are likely to retire and others (as yet unknown) will come into service (e.g. wind). This makes benefits difficult to estimate in advance.

### Stakeholder engagement

3.14 The planning process is coordinated between MISO and stakeholders. Stakeholders give views on model inputs and MISO makes final decisions on the assumptions and planning principles to be used in the modelling. At the point when the project is approved, the allocation of costs is known.

3.15 The foundation for MISO's beneficiaries-pay cost allocation is having a transparent long-term network plan. MISO bases all of its cost allocation calculations off a plan established every two years and then set in stone. Underlying forecasts are developed annually.

3.16 The MISO representative was of the view that stakeholders generally accept the beneficiaries-pay methodology and there is good engagement and participation in associated processes.

# 4 PJM

## Background

4.1 PJM Interconnection is an RTO that coordinates the movement of wholesale electricity across 14 states (65 million people) including all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

4.2 PJM, headquartered in Valley Forge, Pennsylvania, was the world's largest competitive wholesale electricity market until the development of the European Integrated Energy Market in the 2000s.

4.3 PJM introduced a beneficiaries-pay approach to cost allocation for new investments in response to FERC order 1000.

4.4 PJM employs different charging approaches depending on investment type (e.g., market efficiency or reliability). Some of the approaches involve beneficiaries-pay arrangements, some are usage-based and some are allocated within the zone in which the investment was constructed or charged on a postage stamp basis. PJM has approved $36 billion of transmission investments since 2000. It has approved 50 market efficiency projects and around 3,000 reliability projects.

## Attendees

4.5 On 29 March 2018 we met with a number of people at PJM including the following:

(a) Mark Sims, Manager, Transmission Planning (Infrastructure coordination)

(b) Nicolae Dumitriu, Senior Lead Engineer - Market Simulation

(c) Jonathan Kern, Senior Lead Engineer - Transmission Planning

(d) Monica I. Burkett, Member Liaison, Knowledge Management Center.

## What we heard

### Approach to cost allocation

4.6 PJM applies different allocation mechanisms depending on the category of new investment, and also depending on other factors, including whether the investment is local or regional, the voltage level and the magnitude of the upgrade (above or below $5m).

4.7 The various methods for allocating cost employed by PJM include:

(a) ***DFAX method:*** allocation based on estimated usage of the investment by each load zone, determined via flow tracing, i.e. load flow is used as a proxy for benefit. Flow tracing is a mathematical method used by PJM to estimate the percentage of energy flow across a network asset attributable to each load. This method is applied to projects in the “reliability” category, which includes projects associated with restoring the life of aging assets. This is a variable allocation: updated annually based on flows over the assets in each given year.

(b) ***economic benefits method:*** allocation based on estimated benefits from reductions in LMP payments and production cost savings by each load zone (resulting from the investment). This approach is applied to projects valued above $5 million in the “market efficiency” category (for 50% of the value only).

(c) other methods including allocation within the zone in which the investment was constructed and socialisation of cost (eg on the basis of volume or peak usage).

4.8 Projects in the public policy category are allocated to the zone in which the project is located, or otherwise by “state agreement approach”.

4.9 Allocations are made to each of 25 load zones, then allocated to load-serving entities (utilities) within each zone based on their share of coincident peak load within the zone (this within-zone allocation is variable: updated annually).

4.10 Projects in the reliability category account for the bulk of all investments by value (99%).

4.11 PJM has documented its rules, processes and procedures related to the establishment of their benchmark transmission plan and the transmission cost allocation methodology. PJM has allocation manuals for each investment category including a 3,000 page Tariff document and a number of supporting schedules.

4.12 To minimise risks from legal challenge PJM sees it as very important that the allocation rules are developed in precise detail so there is not too much “wiggle room” or engineering judgement.

### DFAX methodology

4.13 For reliability investments (including projects to replace or restore the life of aging assets) with cost above $5m, costs are allocated 50% socialised based on load ratio share and 50% via the DFAX methodology (for larger / multi-zone projects); or 100% via the DFAX methodology (for lower voltage projects).

4.14 PJM has approved around 3,000 reliability projects, a few of which have been challenged and one of which, the Artificial Island Project, has been very controversial. Cost allocation for this project is based on the DFAX methodology.

4.15 In the context of the Artificial Island project, the DFAX method has been criticised on the basis that it results in charging nearly all the costs to parties that consider they will receive a much smaller share of the benefit from the new investment. The purpose of the Artificial Island investment is to resolve stability problems associated with very large single-point generation. The benefits appear to be related to the stability of the whole system. However, the DFAX method allocates more than 90 percent of the cost to one local load zone (based on flow tracing). Following legal challenge, PJM was required to consider other methods for determining the benefits, and did so using at least two different methods with very different modelling outcomes. However, FERC, in its approval of the investment, has upheld the rules as written and therefore the DFAX approach. Construction of the Artificial Island project is due to begin this year.

### Economic benefits modelling methodology

4.16 For market efficiency projects with cost above $5m, costs are allocated 50% socialised based on load ratio share and 50% based on benefits derived from estimated reductions in LMP payments and production cost savings by each load zone (resulting from the investment). Of these, reductions in LMP payments are the dominant driver, as they are generally around ten times the magnitude of production cost savings (e.g. fuel costs).

4.17 Benefits for 15 years from the project in-service date are calculated using the PROMOD model (which is also used by MISO). The model is used to simulate hourly results for a year (8,760 hours). Four years are modelled, including the project in-service year, four years prior to the project in-service date and future modelling looking out three and six years from the project in-service date. Results for in-between years and further future years are interpolated based on the estimated trend.

4.18 Inputs to the model include:

(a) Generation data

(b) Demand and energy

(c) Fuel forecasts

(d) Environmental costs

(e) Power flow case.

4.19 Outputs of the model include:[4]

(a) Hourly LMP

(b) Hourly unit generation and production cost

(c) Hourly binding constraints

(d) Hourly line flows

(e) Environmental emissions

(f) Fuel consumption.

4.20 One central scenario is used to produce a CBA for the project as well as allocate the costs of the investment. Generally speaking, a project is approved if the benefits exceed the costs by a ratio of 1.25 or more. However, PJM also considers other scenarios for information purposes and the decision maker (the PJM Board) takes these into account (an investment decision is not determined solely on the basis of benefits being identified in the base case). There can be cases where the annual base case has to be modified to be appropriate for a specific investment. The cost allocation is calculated once and not revisited.

### Stakeholder engagement

4.21 The benefits modelling approach for market efficiency projects is based on the transmission planning process which is carried out every two years. Input for the planning database, including the annual base case and scenarios, are presented to stakeholders and they provide feedback before PJM decides on final values. In this was PJM considers it can get stakeholder acceptance of the base case in abstract before it is applied to actual projects.

4.22 The model is made available to all stakeholders as an industry standard tool. When an allocation is made it is based on model runs for three or four selected future years (with interpolation for in-between years), using a single “base case” set of assumptions. Sensitivities are provided for information purposes.

PJM provides transparency to stakeholders via a “transmission cost information centre” on PJM’s website. This is “an enormous worksheet with tons of data” about network upgrades, costs and allocations. Customers can use it to estimate their future charges and test sensitivities to selected variables.

[4] Based on our discussions with NYISO and MISO, their models have similar inputs and outputs.

# 5 Professor William Hogan

## Background

5.1 Professor Hogan is a respected energy policy expert who has made important contributions to the policy debate on cost allocation for transmission networks. He has written a number of influential academic and policy papers on the beneficiaries-pay principle for transmission pricing (e.g. Hogan, 2011, *Transmission benefits and cost allocation*). He also played a key role early on in the development of NZ's electricity market and continues to be a thought leader in the evolution of electricity market design including cost allocation for transmission.[5]

## Meeting objectives

5.2 We met Professor Hogan on 28 March 2018 in order to obtain his views on US policy developments and practice with respect to beneficiaries-pay cost allocation for transmission investments.

## What we heard

### Views on implementation of beneficiaries-pay by US ISOs

5.3 Professor Hogan (Hogan) was generally critical of the way that ISOs have responded to FERC's order 1000 that required them to adopt a beneficiaries-pay approach to cost allocation (which he described as "disingenuous"). This was because in many ways they had failed to properly implement beneficiaries-pay or they were "trying to socialise costs" using methods that undermined the principle of beneficiaries-pay.

5.4 Hogan did not approve of categorising investments as "reliability" or "public policy". His view was that all transmission network investments will have benefits that can be measured (regardless of the category they are assigned to). So it is feasible to allocate the costs of all investments according to measured benefits. The introduction of the "public policy" category, under which investment costs can be socialised, was a deliberate move to greater central control (including political control) of investment planning. This move has reflected a shift in the position of the FERC, which has become less supportive of the beneficiaries-pay approach over time. There is pressure to categorise a project as reliability as then it is easier to socialise the costs.

5.5 Hogan generally approved of the beneficiaries-pay approach that NYISO "has on its tariff". He noted that NYISO had not used its beneficiaries-pay approach in practice to allocate costs for the economic category of investments. He wasn't aware that NYISO has recently used its model to allocate 75% of the costs of two public policy projects according to a beneficiaries-pay approach.

5.6 However, Hogan did not approve of the fact that NYISO don't treat generators as beneficiaries (for most investments). In his view an allocation only to load is wrong.

5.7 Hogan also held out MISO as a good example of beneficiaries-pay being implemented well, in particular the approach they used 10 years ago. He may have been referring to the beneficiaries-pay approach that MISO has used to allocate costs for its "market efficiency" category of investments. His understanding was that MISO doesn't allocate costs in this way anymore, but now socialises costs via its multi-value project "MVP"

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5 E.g. Hogan, 2016, *Electricity Market Design: Political Economy and the Clean Energy Transition*

approach. (He wasn't aware that MISO has not abandoned its market efficiency category, and in fact approved market efficiency projects in 2015, 2016 and 2017.)

5.8 Hogan was critical of the "DFAX" method used by PJM to allocate the costs of some investments in the reliability category. This was because it produces "arbitrary" results that do not reflect benefits (as proven with respect to the Artificial Island project). The DFAX method uses flow tracing to determine which zones are users of the investment. For the Artificial Island project, most costs were allocated to a single zone based on flow tracing, however the benefits of the project are more widely dispersed (improvements in system stability). Hogan had expected the DFAX method to be replaced by a more benefit-reflective method after its use for the Artificial Island was challenged. However, FERC has found the method to be acceptable (a stance he was critical of).

### Application of beneficiaries-pay to historic investments

5.9 Hogan did not approve of applying beneficiaries-pay to historic investments (including the HVDC). He said for historic investments, "we are where we are" (which we took to be a reference to the fact that it is no longer possible to influence an investment decision that has already occurred).

5.10 He expressed the view that it's best to allocate the costs of existing assets in a way that does the least harm and avoids as much distortion as possible – recognising that you will never be able to design a pricing method that avoids all distortion and captures all the possible efficiencies, so all you can do is select the best of the practicable options.

5.11 He did acknowledge that where an existing cost allocation for historic investments is grossly unfair or is distorting future investment decisions then a revision may be appropriate. However, in making such revisions, great care had to be taken to avoid causing more harm.

5.12 When asked if he thought the HVDC charge should be reviewed in order to improve investment incentives for generators in the South Island, he said that the problem is variabilisation, i.e., an allocation based on future variable activity.

### Ex ante vs ex post allocation of costs

5.13 In implementing beneficiaries-pay charging, Hogan stressed the importance of making an ex ante cost allocation (e.g. based on a weighted average of forecast scenarios) and then keeping that allocation fixed indefinitely into the future. Even if circumstances changed ex post and the distribution of benefits ended up being different to the distribution that was originally forecast (and used for cost allocation), the beneficiaries-pay charges should not be altered ex post. Otherwise "you get variabilisation of charges" to recover a fixed cost, where charges are a function of marginal consumption, which creates perverse incentives and leads to inefficiency. Efficiency benefits have been realised by stakeholder participation: they know what costs they will be allocated through the beneficiaries-pay approach and so are motivated to involve themselves in ensuring the investment decision is right.

5.14 Hogan explained the logic that underpinned his advocacy of an ex-ante beneficiaries-pays regime for transmission investments. It is an attempt to place a commercial lens over a transmission investment made by a monopoly network owner. The idea is to establish an ex-ante estimate of a transmission investment's costs and benefits (and the beneficiaries), and that the transmission investment only proceeds if benefits exceed costs materially and the beneficiaries approve the investment. Then the costs are allocated to the beneficiaries in proportion to the projected benefits that the transmission investment was expected to deliver. Firmly sticking to the ex-ante cost allocation, even though circumstances may change, was consistent with what occurs with private sector investment planning in competitive markets.

5.15 Hogan admitted that firmly sticking to the ex-ante cost allocation, even though circumstances may change, is a real political problem. However, he also noted that this problem also occurs “in the hot dog business” and “we don’t worry about it there.” He also admitted that cost allocation of transmission investments is politically difficult – and said that his colleague, a former regulator, “thinks I’m crazy” for proposing beneficiaries-pay. He explained that he saw his role as highlighting the economically ideal approach (as opposed to taking into account political considerations).

### Standard of accuracy required in modelling

5.16 Hogan said that perfection was not required on estimating each party’s share of benefits, and rough approximations are acceptable, particularly if the overall benefits of the investment significantly exceed the overall costs.

5.17 The only constraint is that a party’s charge should be less than the value it gets from the investment. In most cases the value will be many times the cost.