Application of constraints in the Declared Transmission System

1. Introduction

The proposal seeks to amend NGR 221(4) which disallows AEMO from including a representation of the DTS when developing the Pricing Schedule. This will enable inclusion of constraints internal to the DTS to be included in the Pricing Schedule where they constrain down withdrawals. This will effectively be a return to the scheduling process used before the changes in 2015.

On 14 July 2016 EnergyAustralia formally requested AEMO under rule 356 to submit this rule change proposal to the Australian Energy Market Commission and request that it be 'fast-tracked'.

2. Background

On 14 August 2014 AEMO presented a brief to the GWCF on an issue arising from the way in which AEMO applies constraints in the Declared Wholesale Gas Market (DWGM) pricing schedules. AEMO had identified that the current Wholesale Market Gas Scheduling Procedures (Victoria) v. 1.0 did not comply with the National Gas Rules (NGR).

Previous practice had been to apply constraints internal to the Declared Transmission System (DTS) in most cases when producing both the Pricing Schedule (PS) and Operating Schedule (OS). However the NGR states that in producing the PS, AEMO must not include a representation of the DTS.

On 8 September 2014 AEMO held the DTS Application of Constraints Workshop. Industry participants discussed the issues involved and potential solutions to the non-compliance.

On 4 May 2015, the Wholesale Market Gas Scheduling Procedures (Victoria) v 2.0 took effect. This introduced a new type of constraint and outlined the circumstances where the existing constraints could be applied.

The February and April 2016 GWCF meetings discussed the process of applying constraints in the Operating and Pricing Schedules within the DWGM – in particular the circumstances under which constraints are applied in one schedule and not the other. A technical workshop with participation from industry and regulators was undertaken on 29 April 2016.

3. Statement of issues

Each day, AEMO issues scheduling instructions to market participants in the DWGM to inject and withdraw gas in each hour for the gas day. Scheduling instructions are the final output in a process that includes the development of pricing schedules and operating schedules for the gas day by AEMO in accordance with the NGR.

A pricing schedule determines the market price, and an operating schedule determines the least cost, physically achievable schedule of gas for the gas day, taking account of transmission constraints.

Where a participant is scheduled to inject gas that was offered above the price set in the pricing schedule, an ancillary payment is made. This compensates participants for injecting more expensive gas.

The application of constraints in the current scheduling process is resulting in poor market outcomes. The particular issues are outlines below.

3.1. Constraints

The types of constraints currently utilised by AEMO as set out in the scheduling procedures are:

Supply and Demand Point Constraints - AEMO may apply SDPCs to reflect contractual, physical and operating constraints for facilities that are external to the DTS to system injection points and system withdrawal points. These are applied to both pricing schedules and operating schedules.

Directional Flow Point Constraints - A special case of the SDPC, a DFPC, allows an injection and withdrawal meter to be paired so that the net flow is subject to a new set of constraints. The feature of the MCE [Market Clearing Engine] is also capable of specifying different maximum flow limits depending on the net direction of flow.

Net Flow Transmission Constraints - A NFTC allows multiple injection and withdrawal meters at a common location to be combined so that the net aggregate flow is constrained to reflect the physical DTS capacity (e.g. pipeline capacity).

NFTCs for Iona and the Northern System have been often applied by AEMO over the past 12 months.

For example, the Iona NFTC represents a limitation of gas flowing across the system from east to west. Where controlled withdrawals from the west of the system scheduled in the PS cannot be met physically, these withdrawals will be constrained down in the OS. Either a corresponding reduction in injections or increase in withdrawals from the east of the system is required. Additional injections may also be required from SWP to meet uncontrolled withdrawal demand in the west of the system.

The proposal allows AEMO to apply the NFTC in the PS which will ensure controlled withdrawals from the Iona Close Proximity Point[1] (CPP) that cannot be physically met will not be used to set the gas price.

However where uncontrolled withdrawals are physically required to be met by increased injections at the Iona CCP, applying the NFTC in the PS will result in an increased gas price.

To maintain the PS and OS differential where additional injections are required, a NFTC should only be applied in the PS up to the point where withdrawals are constrained down. This could be effected by either applying a reduced NFTC, or by applying SDPCs at the system injection points which limit maximum withdrawals only. This maintains the ancillary payments available for the constrained on injections.

[1] Iona, SEA Gas, Mortlake and Otway system injection points

Figure 1 NFTC Hourly Max Net Withdrawals applied in 2016, Data from INT112B

3.2. Ancillary Payments

Under NGR 239, ancillary payments can be made only where a participant is scheduled to inject or withdraw gas in the Operating Schedule above the amount they were scheduled in the Pricing Schedule.

The combination of rule 239(3)

> *Subject to subrules (4), (5) and (6), any Market Participant who is given a scheduling instruction to inject or withdraw more gas than the quantity of gas that the Market Participant was scheduled to inject or withdraw under the relevant pricing schedule, is entitled to receive an ancillary payment in accordance with this rule.*

and rule 239(6)

> *If a Market Participant is instructed by AEMO to inject or withdraw a quantity of gas less than the amount of gas specified for injection or withdrawal (as the case may be) by that Market Participant in the pricing schedule, that Market Participant is not entitled to be paid ancillary payments for that amount.*

Where constraints internal to the DTS require injections to be scheduled out-of-merit order, the additional and more expensive gas required to meet system security does not set the gas price for that schedule. This allows the cost of the additional gas to be allocated on a cost-to-cause basis and the impact of constraints to be contained solely in uplift and ancillary payments (AP). Participants are incentivised to limit their bids as the cost of the system constraint will be allocated to the causer. Constrained on withdrawals are also eligible for APs to compensate participants for taking gas at a price above their bid price.

However, a design decision was originally made to not allow APs for constrained down injections and withdrawals. In these cases, participants have no incentive to limit their bids due to an expected constraint as the costs are not allocated to the causer. At the time, withdrawals from the DTS at their current levels were not anticipated.

Following the introduction of the new procedures in May 2015, market participants identified issues with market outcomes where constraints internal to the DTS were active. Notably, maintenance on the Brooklyn Compressor restricted net withdrawals from the SWP to zero in the OS, yet the PS included all withdrawal bids. As the constraint does not cause APs in this case, there is no incentive for participants to minimise the impact of the constraint. Hence the PS is developed using demand that is not feasible on the day - causing a higher gas price unrepresentative of the true supply/demand balance. Poor market outcomes can be expected whenever 'Iona' or 'Northern System' NFTCs are applied.

The PS and OS differential can signal the cost of a constraint where constrained on injections are required. It also allows this cost to be excluded from the gas price paid by the market. However this is not the case where withdrawals are constrained down.

The difference between constrained down APs and constrained on APs warrants a different treatment of how the constraints are applied in developing the PS and OS.

3.3. Reduced trading

In some scenarios, offers to inject gas below the market price are being constrained down even where they would act to relieve the applied constraint. This is a counter-intuitive and costly result of the current scheduling process. This can occur when injections at other system injection points that are offered at a lower price are constrained down in the OS. The lower priced injections set the price in the OS which precludes the higher priced injections. Inclusion of the constraint in the pricing schedule would result in a reduced differential between the PS and OS, allowing the injection to occur.

3.4. Illustrative example 17 March 2016

- NFTC applied: Hourly Max net withdrawal quantity from Iona CPP: 3,710GJ every hour across the day. This is a maximum of 89,040GJ for the day.
- 6am withdrawal bids from the Iona CCP priced at $800 totaled 108,000GJ.
- Controlled withdrawals de-scheduled by
  - 9,799GJ at Iona
- Injections de-scheduled by
  - 4,364GJ at Iona
  - 2,363GJ at VicHub
  - 3,000GJ at Culcairn

A number of the issues with the current scheduling process highlighted in this rule change proposal were demonstrated on this day:

- Injection offers priced below the market price were de-scheduled in the Operating Schedule. Due to higher priced injection offers being constrained off first, participants are incentivised to offer at low prices not reflective of their willingness to sell. This creates risk and uncertainty for participants with respect to both price and volume.
- Both injections and withdrawals are constrained off at the same CPP. Injections at Iona priced below the market price would have relieved the constraint yet were not scheduled.

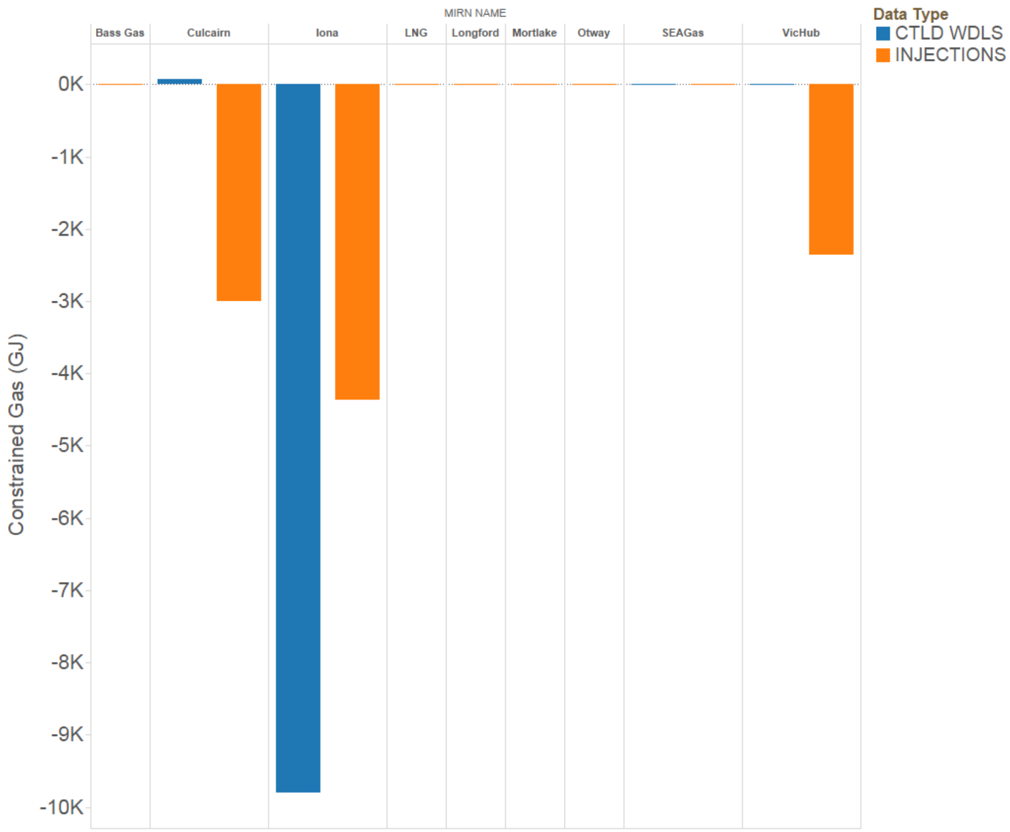

Figure 2 Difference between 6.00am OS and PS, 17 March 2016, Data from INT235

4. Description of the rule

A change should be made to NGR 221 (4) so that:

In developing the PS, AEMO should account for constraints internal to the DTS.

- Where a system constraint would act to physically limit scheduled withdrawals from the DTS, AEMO will apply a constraint to represent this in the pricing schedule.

Note that, a differential between the PS and OS will remain in cases where constrained on injections are required. The specific changes proposed to NGR 221(4) are:

> *The inputs and assumptions set out in subrule (3) must be applied by AEMO in an optimisation program in which valid bids submitted by Market Participants are used to produce pricing schedules that specify injections and withdrawals of gas to be made in each gas day in a way that minimises the cost of satisfying the expected demand for gas in that gas day and for the purpose of doing so, AEMO must ~~not include a representation of the declared transmission system.~~ include only constraints on withdrawals from the DTS*

5. Achievement of the National Gas Objective (NGO) and expected benefits

During the 15/16 summer period, the PS was often based on a demand 10-20% higher than what was technically feasible. Market sensitivities show price outcomes may have been $1-$2 / GJ above what would have been the case under this proposal. It is difficult to determine the exact impact as the scheduling phenomenon caused participants to change behavior over this period.

There is also an on-going risk of an $800/GJ price based on unrealistic demand that participants will be unable to effectively hedge using injections. This creates significant uncertainty and risks for participants.

This change will also provide a mechanism for additional trades to occur where currently offers to inject below the market price that would act to relieve a constraint are being constrained down.

The reduced uncertainty and risk in the market will enable more effective hedging and trading of gas between participants. An overall lower gas price is expected and a corresponding lower price paid by Victorian consumers. Withdrawals from the DTS are forecast to increase in the future. As a result, the negative impact from the current scheduling process is also expected to rise.

Market participants updated trading strategies when the scheduling procedures were changed in May 2015. The proposal is largely a reversion to how the market operated before this date and as such there should not be significant impact to the industry to adjust to the change. As the process of setting SDPCs to constrain withdrawals in the PS was undertaken by AEMO prior to 4 May 2015, system and process changes are expected to be minimal for both AEMO and participants. Therefore the proponent believes that the proposed change is technically, operationally, and economically feasible.

The proponent has considered whether this rule change proposal is likely to contribute to the advancement of the NGO. The NGO is stated in section 23 of the National Gas Law:

> *"The objective of this Law is to promote efficient investment in, and efficient operation and use of, natural gas services for the long term interests of consumers of natural gas with respect to price, quality, safety, reliability and security of supply of natural gas."*

The proposal will contribute to the advancement of the NGO by promoting the efficient operation and use of natural gas in the long term interests of consumers of natural gas with respect to price, reliability and security of supply. If this change is not progressed:

- market participants will remain unable to hedge effectively in the market where constraints internal to the DTS limit withdrawals
- Market outcomes will continue to be unpredictable and unreflective of the supply/demand balance
- Many trades between willing counterparties will not occur.

The proposed methodology will result in a lower or unchanged gas price in all cases compared with outcomes of the current procedures.

6. Summary of consultation

[Attached following AEMO consultation]