UNIVERSIDADE FEDERAL DO RIO GRANDE DO SUL
ESCOLA DE ENGENHARIA
DEPARTAMENTO DE ENGENHARIA QUÍMICA
PROGRAMA DE PÓS-GRADUAÇÃO EM ENGENHARIA QUÍMICA

Controle Ativo de Golfadas em Poços de Petróleo Offshore

TESE DE DOUTORADO

Fabio Cesar Diehl

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Tese de Doutorado apresentada como requisito parcial para obtenção do título de Doutor em Engenharia.

Área de concentração: Controle Avançado

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A Comissão Examinadora, abaixo assinada, aprova a Tese intitulada *Controle Ativo de Golfadas em Poços de Petróleo Offshore*, elaborada por Fabio Cesar Diehl, como requisito para obtenção do Grau de Doutor em Engenharia.

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Resumo

A produção de petróleo e gás é caracterizada pelo transporte dos fluidos do reservatório até as instalações de processamento, onde as correntes produzidas são tratadas e enquadradas de acordo com as especificações de comercialização, descarte ou reinjeção. A etapa de transporte dos fluidos até a planta de processamento é governada por complexos fenômenos de escoamento multifásico em longas tubulações, principalmente quando o ambiente de produção é marítimo. Esta combinação de cenários pode induzir o surgimento de padrões cíclicos de oscilação de pressão-vazão no escoamento do poço. Este fenômeno é classificado como um ciclo limite estável, que no estudo da dinâmica de sistemas é um comportamento não linear gerado por uma trajetória fechada no espaço de fase com formato de espiral quando o tempo tende ao infinito. Na indústria do petróleo, este ciclo limite é chamado de golfada, escoamento intermitente, *slugging* ou *slug flow* e é constituído pelo deslocamento de ondas de massa de fluido nas linhas de produção, o que coloca as instalações em risco e reduz a capacidade produtiva dos poços. Muitas publicações sobre métodos de controle deste fenômeno têm discutido o problema desde a década de 1980, contudo muitos pontos permanecem em aberto visto a complexidade e diversidade de cenários possíveis. Além disso, poucas aplicações em campo são reportadas na literatura, sendo que a maior parte dos trabalhos práticos publicados apresenta descrições limitadas que dificultam a replicação das metodologias utilizadas. Portanto, esta tese objetiva explorar abordagens de controle por retroalimentação (controle ativo) para problemas de ciclo limite em poços de petróleo em águas profundas e ultraprofundas. Aspectos como controle preditivo, multivariável e não linear são discutidos e explorados no trabalho, culminando em duas diferentes aplicações de campo descritas em detalhes. Até onde se sabe, esta é a primeira vez que estratégias de controle preditivo e de controle não linear são apresentadas na literatura em aplicações reais de controle ativo de golfadas. Como resultado, foi possível minimizar os efeitos adversos das golfadas e aumentar a produção dos poços em cerca de 10% nas aplicações reais.

Abstract

Oil and gas production is characterized by the transport of fluids from the reservoir to the processing facilities, where the streams produced are treated and fitted to commercial, disposal or reinjection specifications. The fluid transport stage to the processing plant is governed by complex multiphase flow phenomena in long pipelines, especially when the production environment is marine. This combination of scenarios can induce the appearance of singularities in the flow stability, resulting in the formation of cyclic flow patterns. This phenomenon is classified as a stable limit cycle, which in system dynamics means a nonlinear behavior generated by a closed trajectory in the phase space with a spiral shape when time tends to infinity. In the oil industry, this limit cycle is called slugging, slug flow or intermittent flow and causes pressure and flow waves in the well, exposing the facilities to risk and reducing production capacity. Several publications on methods of controlling this phenomenon have discussed the problem since the 1980s, however many points remain open due to the complexity and diversity of possible scenarios. Furthermore, few field applications are reported in the literature, and most of the published works present poor descriptions that make it hard to replicate the methodologies deployed. Therefore, this thesis aims to explore feedback control approaches (active control) for limit cycle problems in oil wells in deep and ultra-deepwaters environment. Aspects such as predictive, multivariable and nonlinear control are discussed and explored in this work, resulting in two different field applications described in detail. As far as is known, this is the very first time that predictive control and nonlinear control strategies are presented in the literature to deal with slugging in actual applications. As a result, it was possible to minimize the adverse effects of the slug flow and increase the production of the wells by about 10% in actual deployments.

Sumário

Capítulo 1

Introdução

1.1 Uma Breve História da Produção de Petróleo

Em 1846, às margens do Mar Cáspio, era aberto o primeiro poço de petróleo no mundo[1], na cidade de Baku, hoje Azerbaijão, com 21 m de profundidade. Na época, o petróleo era destinado principalmente à produção de querosene de iluminação. Entretanto, a transição dos meios de produção de forma manual para a manufatura baseada em máquinas, período referente à Revolução Industrial, demandava melhores lubrificantes do que as gorduras animais e os derivados de carvão[2], utilizados até então. A alta qualidade e o baixo preço dos derivados de petróleo impulsionaram a busca por jazidas mais volumosas e profundas em detrimento às coletas rústicas realizadas naquela época.

Na década de 1850 era perfurado o primeiro poço de petróleo dos Estados Unidos[2], na Pensilvânia, com profundidade também de 21 m e uma produção que chegou a atingir os 25 m³/d. Depois de 15 meses da descoberta havia cerca de 70 poços em produção naquela região. Na década seguinte, foi descoberto, no Canadá, o primeiro poço jorrante do mundo a 60 metros de distância vertical da superfície. Também conhecido como poço surgente, este tipo de poço não requer estímulo externo, como o bombeamento mecânico, por exemplo, para produzir o óleo[1].

Talvez o maior marco após a perfuração do primeiro poço do mundo tenha sido a criação da Standard Oil Company, por meio de empresários americanos liderados por John D. Rockfeller, no início dos anos 1870[1]. A companhia estabeleceu padrões de qualidade para os derivados e 10 anos mais tarde o querosene tornava-se o principal produto de exportação dos Estados Unidos[3]. Ao final do século XIX a corrida pelo petróleo avançava em diversas partes dos Estados Unidos, Ásia e Leste Europeu. O propulsor desta expansão eram novos produtos necessários à indústria, como óleo combustível, graxas, vaselina, parafina e a gasolina, utilizada principalmente como solvente nesta época[3].

As primeiras operações de produção sobre água, ambiente referenciado como *offshore* no jargão da indústria do petróleo, foram registradas nos Estados Unidos ao final do século XIX. Apesar de haver divergências entre historiadores, ao que tudo indica em 1891 se iniciou a primeira produção de petróleo *offshore* do mundo, no Grand Lake Saint Marys em Ohio, em lâminas d’água de 1,5-2,1 m de profundidade. Nos 10 anos seguintes, cerca de 100 poços foram perfurados no lago, sobre estruturas de madeiras, com produção que variava entre 25-250 barris por dia[4]. A foto do Departamento de Recursos Naturais de Ohio, apresentada na Figura 1.1, ilustra as atividades de perfuração no lago no ano de 1890. Alguns anos mais tarde, em 1897, iniciava-se a produção *offshore* na costa oeste dos Estados Unidos, no Canal de Santa Barbara, Califórnia. Os poços eram instalados em píeres de madeira para suportar equipamentos usualmente empregados em operações secas[5]. Cinco anos mais tarde havia cerca de 400 poços similares produzindo no campo, chamado de Summerland, que aqueceram a economia da Califórnia durante 25 anos.

Figura 1.1 – Primeiras atividades de perfuração offshore do mundo, em Grand Lake St. Marys, Ohio[4].

No Oriente Médio, exploradores ingleses iniciaram as primeiras perfurações no Irã no início do século XX, encontrando a primeira importante jazida somente em 1908[1]. No Iraque, as buscas iniciaram-se na década de 1920, resultando na descoberta de quantidades vultuosas de petróleo que foram exploradas através de empresas inglesas, francesas e norte-americanas[3]. Na década seguinte, foi descoberto o campo supergigante de Burgan no Kuwait, o segundo maior do mundo até hoje, com reservas estimadas em cerca de 70 bilhões de barris de óleo[6]. O primeiro poço produtor de Burgan foi perfurado em 1938, a uma profundidade de 1.120 m da superfície; era surgente e produzia mais de 4.000 bopd (*barrels of oil per day*) de um óleo de alta qualidade, com 32° API.

Na Arábia Saudita, as concessões de exploração foram outorgadas em 1933 para a empresa norte-americana Standard Oil of California (Socal)[7], que alguns anos depois se associou à Texaco criando a Arabian American Oil Company (Aramco)[2]. Em 1948, em profundidades de 2.000-2.330 m da superfície do deserto saudita[8], a Aramco descobriu a maior reserva de petróleo do mundo, o campo de Ghawar[7]. Para se ter uma ideia da sua dimensão, o campo de Gahwar possui uma extensão de 280 km por 30 km, e entre 1980 e 2010, produziu sozinho uma média de 5 milhões de barris de óleo por dia, o que equivaleu a cerca de 6,25% de todo o consumo de óleo do mundo na época[8]. O poço Ain Dar #1, primeiro poço de Ghawar, iniciou sua produção em 1951 com uma taxa de 15.600 bopd e produziu sozinho até 2008 cerca de 152 milhões de barris de óleo[9]. Não se sabe exatamente a quantidade de óleo de Ghawar, contudo as estimativas variam em torno de 190-300 bilhões de barris. A única operadora deste campo é a Aramco, que desde 1980 é totalmente controlada pelo estado da Arábia Saudita, passando a se chamar Saudi Aramco Oil Company. Atualmente, a Saudi Aramco é considerada a companhia de óleo mais valiosa do mundo[10], visto seu baixo custo de produção, em torno de US$ 3 por barril[11], e suas reservas comprovadas de cerca de 270 bilhões de barris de petróleo[12].

A primeira metade do século XX mostrou que a produção de petróleo em novas fronteiras tecnológicas no mar era complexa e de alto custo. Dos primeiros poços em ambiente aquático até 1930, houve pequenas evoluções nas instalações, que permitiram não muito mais do que a transição de estruturas de madeira para estruturas de aço. O aprimoramento e adaptação requerida para a evolução além das fronteiras tecnológicas, em sistemas de exploração e produção, eram constantes e levaram as empresas petroleiras a adotarem ações cooperativas por meio de esforços conjuntos de pesquisa e desenvolvimento (P&D). As primeiras grandes dificuldades enfrentadas foram no Golfo do México (GoM), nas décadas de 1940 e 1950, devido às distâncias das jazidas da costa e os problemas de produzir em ambiente marinho. Esta realidade levou as operadoras a criarem os seus próprios centros de P&D, associados a instituições científicas, universidades e empresas detentoras de capacitação em inovação em exploração e produção de petróleo[2].

Impulsionada por esta nova estratégia colaborativa, os avanços tecnológicos foram se acelerando de modo que de 1947[13] até o início da década de 1960[14,15] a lâmina d'agua passou de 4,6 m para 48 m de profundidade, o que representou um aumento de 10 vezes na capacidade das sondas de perfuração *offshore*. A Shell despontava como principal empresa em capacitação tecnológica, graças a massivos investimentos em P&D, e em 1962 a empresa inaugurava a primeira plataforma de perfuração móvel semi-submersível do mundo, com capacidade de realizar explorações em águas de até 91,5 m de profundidade[2]. Foi então que, em 1965, a Shell batia o recorde mundial de profundidade ao instalar uma plataforma de produção em 86 m de coluna de água no Golfo do México.

Nesta mesma época, eram descobertas as primeiras grandes jazidas de petróleo do Mar do Norte nas costas marítimas da Noruega e Inglaterra. O petróleo do Mar do Norte estava em uma região mais profunda do que a área até então explorada no Golfo do México, o que exigia maiores desenvolvimentos tecnológicos de exploração e produção do que aqueles que eram disponíveis no mundo naquela época[2]. A produção em grande escala só viria a se concretizar na década seguinte.

No Brasil, até a década de 1950, as buscas por petróleo, majoritariamente liderada pelo setor privado, esbarravam na falta de capacitação técnica e equipamentos de perfuração. A prospecção era feita quase de modo aleatório, visto que havia pouco conhecimento da geologia do território nacional e praticamente nenhum conhecimento na área de engenharia de petróleo[2]. Os resultados desta frente exploratória eram sempre poços secos. A primeira descoberta relevante de óleo no Brasil aconteceu no Recôncavo Baiano no final dos anos 1930, em Lobato[16], onde foram perfurados 17 poços que não se mostraram comercialmente viáveis devido à sua baixa produtividade. Os fracassos na exploração de petróleo até 1950, a forte dependência da importação de derivados que o Brasil vivia (as importações de gasolina saltaram de 0,5 milhão de m³ para 2,3 milhões de m³ de 1945 até 1950[18]) e o nacionalismo pós Segunda Guerra Mundial, que levantava preocupações sobre a soberania nacional e suspeitas sobre as companhias estrangeiras, resultou na criação da Petrobras em 1953. A missão da companhia era abastecer o mercado interno de derivados e intensificar a prospecção de petróleo no Brasil. A partir da exploração *onshore* do território brasileiro, nos 10 anos seguintes, descobriu-se petróleo em escala comercial, principalmente na região nordeste do país. Contudo, as descobertas não eram de grandes reservas, e em meados da década de 1960 o Brasil ainda importava dois terços do seu consumo de petróleo[17]. A partir de 1966 a Petrobras decidiu explorar a plataforma continental marítima e para tal encomendou a construção da plataforma Petrobras I (P-1), uma unidade de perfuração para exploração em lâminas de água de até 30 m. Esta foi a primeira plataforma de perfuração construída no Brasil, no estaleiro de Mauá em Niterói, com base em projetos de empresas americanas[2]. A primeira descoberta no mar data de 1968, no Campo de Guaricema, localizado no estado de Sergipe, em profundidades de 28 m de lâmina d'água. No mundo, em 1968 as perfurações já eram feitas em águas com mais de 300 m de profundidades[18].

Apesar dos avanços da indústria de petróleo *offshore* nos blocos regionais do Golfo do México, Mar do Norte e Costa do Brasil, o setor só veio a deslanchar economicamente na década de 1970, impulsionado pela primeira crise do petróleo em 1973, que quadruplicou o preço do petróleo no mundo (de US$ 3 para US$ 12)[19]. A década de 1970 ainda passaria por uma segunda crise do petróleo, ocasionada pela guerra entre Irã e Iraque, que fez com que os preços do petróleo chegassem a US$ 38 em dezembro de 1979[20]. A média de preço do Brent, em 1980, foi de US$ 37,42, o que equivale a US$ 111,30 corrigido pela inflação americana até julho de 2017[21].

As dificuldades impostas pelas crises da década de 1970 estimularam o investimento na prospecção e desenvolvimento de tecnologias para produzir óleo em águas cada vez mais profundas. A Figura 1.2 apresenta os resultados desses investimentos na Petrobras[22]. A capacitação gerada colocou o Brasil entre os líderes mundiais em tecnologia na produção de petróleo *offshore*. Em 1992, a Petrobras recebeu o prêmio OTC (*Offshore Technology Conference*), a maior conferência de tecnologia *offshore* do mundo, em reconhecimento aos avanços tecnológicos e de economicidade em projetos de águas profundas no Campo de Marlim[23]. Por mais três vezes a companhia recebeu este prêmio: em 2001, pelos avanços em águas ultra profundas, no Campo de Roncador, em 2015 por uma série de desenvolvimentos que culminaram na viabilização do Pré-Sal[23]; e em 2021 pelas inovações desenvolvidas para viabilizar o campo de Búzios, o maior campo em águas profundas do mundo. Algumas conquistas interessantes da Petrobras, nos últimos anos, incluem a perfuração do poço mais profundo do mundo, no Golfo do México em 2009, com 10.685 m de profundidade total, em lâminas d'água de 1260 m e o registro do recorde de nacional de profundidade d'água, na bacia de Sergipe-Alagoas em 2015, de 2990 m. Apenas seis poços exploratórios superaram essa profundidade no mundo, sendo três deles, perfurados pela companhia ONGC, na Índia, e outros três pelas empresas Murphy e Chevron, no Golfo do México (EUA). Até 2015, dos 50 poços com maior lâmina d´água no mundo, a Petrobras havia perfurado 15 (30%)[22].

A expansão das atividades *offshore* foi um fenômeno mundial e outras regiões cresceram de modo acelerado. A Figura 1.3, por exemplo, ilustra a evolução da prospecção no Golfo do México (GoM) desde o início da produção até os dias de hoje[24]. O gráfico reúne mais de 53.000 perfurações e retrata o avanço em direção a maiores profundidades oceânicas ao longo dos anos. Apesar da grande maioria dos poços do GoM encontrar-se em águas rasas, como revelado na Figura 1.4, em 2017 mais de 80% da produção de óleo da região era oriunda de instalações em águas profundas[25] – na indústria do petróleo, a classificação da profundidade da lâmina d'água é dividida em 3 faixas[26]: águas rasas, até 300 m (1.000 ft); águas profundas, entre 300-1.500 m (1.000-5.000 ft); e águas ultra profundas, acima de 1.500 m (5.000 ft).

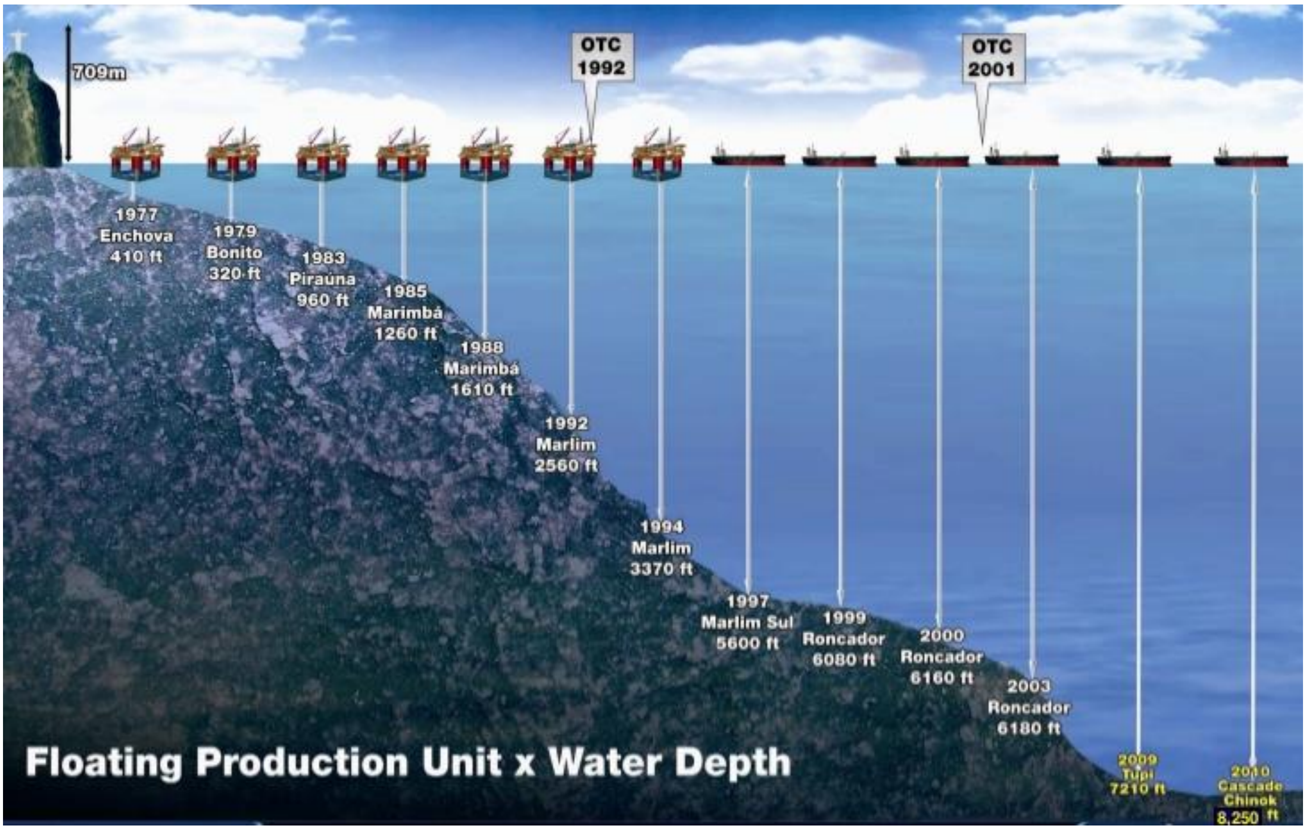

Figura 1.2 – Recordes batidos pela Petrobras em águas no Brasil[22].

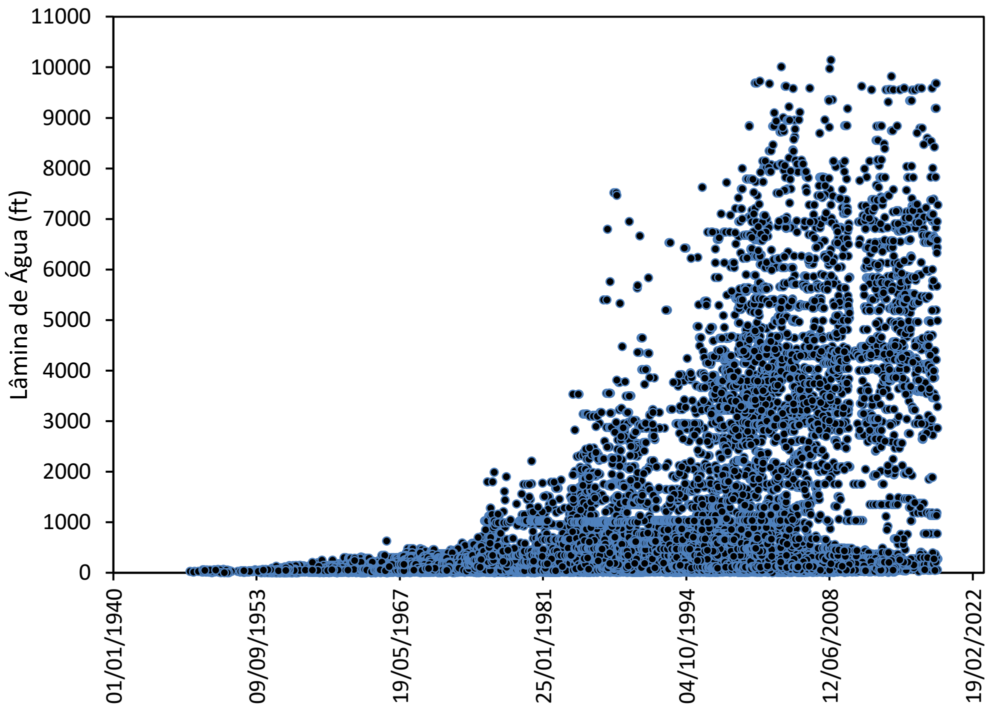

Figura 1.3 – Poços perfurados no Golfo do México[24].

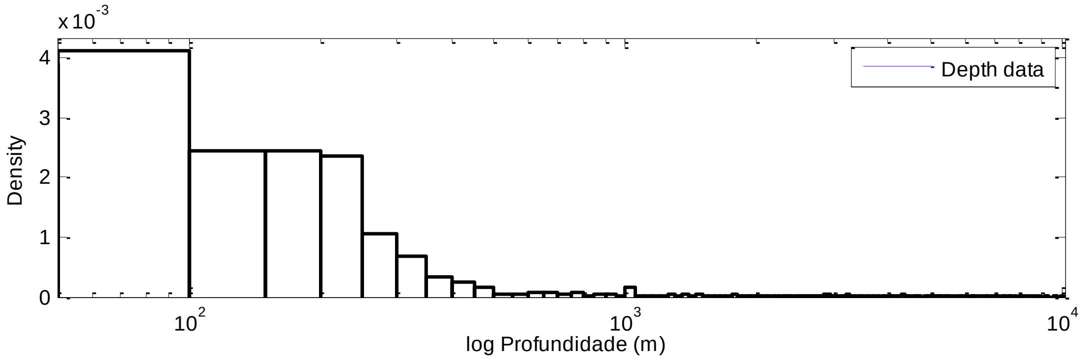

Figura 1.4 – Distribuição de todos os poços perfurados no GoM até 2018[24].

Localizado na plataforma continental Européia, com média de profundidade das águas de 95 m e máxima de 700 m, o Mar do Norte lidera o número de unidades *offshore* no mundo[27], como é mostrado na Figura 1.5. Cinco países estão envolvidos na produção de óleo do Mar do Norte: Noruega, Reino Unido, Dinamarca, Alemanha e Holanda[28]. Embora os maiores produtores do bloco sejam respectivamente a Noruega e o Reino Unido, onde o primeiro detém aproximadamente 50% das reservas estimadas de óleo da região[29], os únicos países exportadores de petróleo da Europa em 2016 foram a Noruega e a Dinamarca. A Equinor Energy SA, antiga Statoil, é responsável por mais de 40% da operação na costa Norueguesa, sendo dona da marca de 63% das descobertas da área[30].

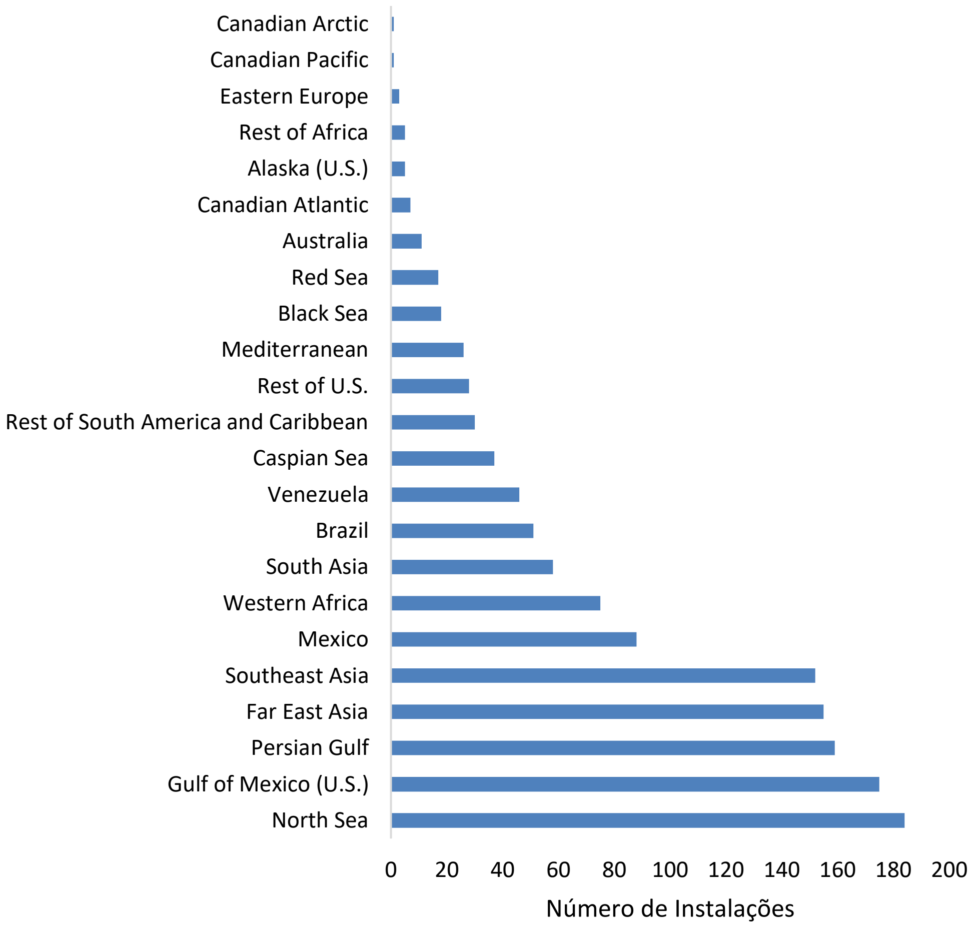

Figura 1.5 - Número de unidades de produção *offshore* em 2018 por região de produção[30].

Apesar do Mar do Norte e do Golfo do México concentrarem o maior número de instalações *offshore*, a produção de óleo no mar é mundialmente liderada pela Arábia Saudita, seguida pelo Brasil, de acordo com a Figura 1.6[31]. A produção da Arábia Saudita é operacionalizada através da Saudi Aramco no Golfo Pérsico, que é dona do primeiro e terceiro maiores campos de petróleo *offshore* do planeta (Campo de Safaniya e Manifa, com reservas estimadas em 36 e 13 bilhões de barris de óleo)[32]. O Golfo Pérsico é banhado por águas rasas, cuja profundidade média é de 50 m e raramente é encontrada alguma área mais profunda do que 90 m[3 3].

Saíndo do Oriente Médio e cruzando o continente africano, chega-se a uma importante região de produção *offshore* no mundo, o Oeste da África. Em 2015, esta área foi responsável pela produção de 5,3 MM bopd (6% da produção global), sendo 4,4 MM bdop em ambiente marítimo (17% da produção *offshore* do mundo)[34]. Os maiores produtores de petróleo do Oeste da África são a Nigéria, Angola e Algéria[35] e o cenário de produção envolve jazidas localizadas em águas rasas e profundas[36].

Neste cenário petrolífero, o Brasil desponta como a grande promessa do mercado no mundo *offshore*. Isto deve-se às descobertas feitas no pré-sal, que constitui a mais nova fronteira tecnológica da indústria do petróleo. O Pré-Sal é uma sequência de rochas sedimentares formadas há mais de 100 mihões de anos, durante a separação do antigo continente Gondwana, que deu origem aos atuais continentes Americano e Africano[37]. Entre os dois continentes formaram-se depressões que deram origem a grandes lagos onde se depositaram as rochas geradoras do pré-sal. Os rios dos continentes carregaram material orgânico que se depositou na fissura. Com o afastamento dos blocos continentais o espaço foi coberto por águas do Oceâno Atlântico, dando início a formação de uma camada de sal que atualmente pode chegar a 2.000 m de espessura. Esta camada de sal depositou-se sobre os sedimentos orgânicos acumulados, retendo-os por milhões de anos, enquanto que processos termoquímicos transformaram a matéria orgânica em hidrocarbonetos (petróleo e gás natural)[37].

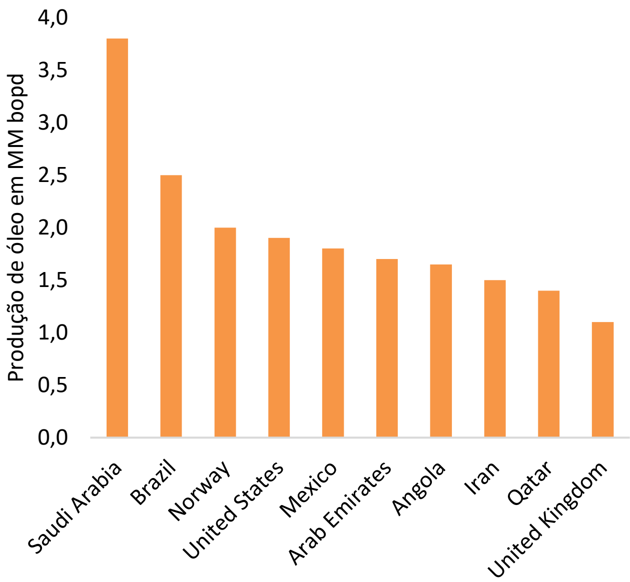

Figura 1.6 – Os 10 países com maior produção de petróleo *offshore* em 2017[31].

A região do pré-sal encontra-se sob águas ultra profundas, entre 2.000 e 3.000 m de lâmina d’água, a uma distância da costa terrestre de 200 a 300 km. Existe muita especulação sobre o potencial das reservas de petróleo na camada do pré-sal, mas a única maneira de se chegar a um número concreto é através de perfuração. Hoje as reservas comprovadas e recuperáveis do pré-sal, de acordo com a Agência Nacional do Petróleo (ANP)[38], estão em torno de 15 bilhões de barris de óleo.

De 2010 até 2021, a Petrobras deu um salto na produção do pré-sal de 41 mil bopd para 2 milhões bopd[37], graças a fortes investimentos em P&D. Um exemplo desses avanços foi o tempo médio para construção de um poço do pré-sal, que caiu de 310 para 89 dias de 2010 a 2016[37]. Uma série de feitos pioneiros e tecnologias foram desenvolvidas para a viabilização do pré-sal, entre estas o primeiro sistema de bóias de sustentação de *risers* da indústria do petróleo; o mais profundo *riser* rígido tipo "*lazy wave*"; o mais profundo *riser* flexível; primeiro sistema de separação de CO_2 de gás natural com reinjeção em reservatório em águas ultra profundas; o mais profundo poço submarino de injeção de CO_2; primeira utilização no mundo do método de recuperação de reservatório através de injeção alternada de água e CO_2; entre outros[37].

1.2 A Estabilidade em Escoamento Multifásico

A produção de petróleo pode ser operacionalmente dividida em duas grandes etapas: o transporte dos fluidos do reservatório até as instalações de superfície e o tratamento dos fluidos para que sejam especificados para exportação (óleo e gás) e descarte (água). A Figura 1.7 ilustra uma unidade de produção de petróleo e gás em ambiente *offshore*.

Ao longo da depleção de um campo de petróleo a pressão no reservatório tende a diminuir e juntamente consigo a força motriz para o transporte do petróleo até as instalações de superfície. Há diversas formas de suplementar essa redução de energia disponível, sendo a mais comum a injeção de gás natural na base do poço para reduzir o peso da coluna de líquido do sistema de produção. Este método de elevação artificial é chamado de *gas lift*[38]. Na Petrobras, esta técnica de elevação artificial é a mais utilizada em ambiente *offshore*.

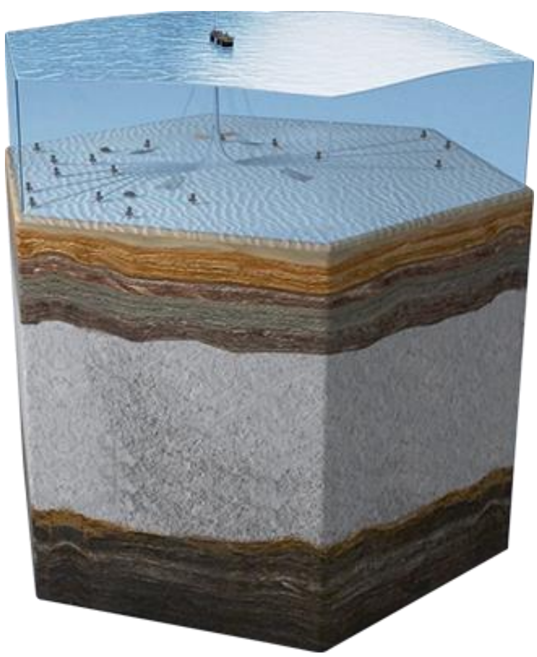

Figura 1.7 – Esquema de um sistema de produção *offshore* no pré-sal[37].

A coexistência das fases óleo, gás e água nos poços e linhas de produção, trechos constituídos de tubulações que chegam a milhares de metros de extensão, quando em águas profundas e ultra profundas, propicia condições de complexas de escoamento multifásico. A principal característica do escoamento multifásico, como o próprio nome sugere, é a coexistência e fluidos em diferentes fases, que podem resultar em descontinuidades associadas às suas propriedades[39].

No transporte dos fluidos para a superfície, o escoamento multifásico pode percorrer sinuosos obstáculos entre rochas, leito marinho e oceano, impondo condições geométricas adversas à produção. Uma das implicações deste tipo de instalação é o surgimento de padrões de escoamento cíclicos no transporte da mistura multifásica. Dependendo das propriedades dos fluidos (viscosidade, densidade, frações mássicas das fases, etc.) e das condições de escoamento (velocidade das fases, direções de escoamento, etc.) podem-se formar padrões de fluxo de estabilidade marginal. A principal característica do escoamento cíclico, chamado de golfada no jargão da indústria de petróleo, é a produção de ondas de pressão intermitentes e oscilações na vazão dos fluidos. Como consequência, os riscos de descontinuidade operacional tornam-se eminentes[40], e perdas de produção são ocasionadas pela operação à margem da estabilidade. A operação neste padrão de fluxo pode chegar a gerar perdas de produção na ordem de 20-40%[41,42]. Mais detalhes sobre os mecanismos que dão origem às golfadas serão abordados nos próximos capítulos deste trabalho. O tema também é amplamente abordado na literatura[42,43,44,45,46,47,48,49,50] desde a década de 1970.

Trabalhos como o de Jansen *et al*. (1999)[51] e Di Meglio (2011)[52] discutem os impactos do surgimento de ciclos limite na produção de petróleo. Por exemplo, a Figura 1.8 mostra um diagrama de bifurcação que representa a produção de óleo em relação à vazão de gás injetado na coluna de produção[51]. Para este sistema, existe uma mudança qualitativa na estabilidade quando a vazão de *gas lift* é aproximadamente 1,1 kg/s. Matematicamente este ponto é classificado como uma singularidade, ou um ponto de bifurcação Hopf, que na prática significa que neste ponto há uma mudança nas características dinâmicas do sistema. Para valores de vazão de gás acima de 1,1 kg/s o sistema apresenta um comportamento estável, enquanto para valores abaixo de 1,1 kg/s o sistema comporta-se de maneira oscilatória, ou golfante. A linha descontínua mostra a média de produção de petróleo do poço em uma faixa de valores muito menor do que no equilíbrio mostrado na linha contínua. Isto quer dizer que operar golfando reduz a eficiência do sistema de produção. Muitos autores se referem ao ciclo limite com um comportamento instável, que sob o ponto de vista matemático não é um termo rigorosamente correto, no entanto, para fins práticos, esta essa terminologia será eventualmente utilizada neste trabalho.

Outra forma de verificar os efeitos da ocorrência de ciclo limite na produção é através da avaliação da pressão imposta à jusante das linhas de elevação de petróleo. Em Di Meglio (2011)[52] é apresentado um diagrama de bifurcação que ilustra o comportamento típico de um poço golfante, através da análise da vazão de óleo produzido em relação à abertura da válvula *choke* no *topside*. Conforme verificado na Figura 1.9, entre 0-15% de abertura da válvula o sistema apresenta um comportamento estável. A partir de aproximadamente 15% há uma perda de estabilidade e a vazão passa a oscilar entre os máximos e mínimos simbolizados pela curva de cor preta. A vazão média de óleo produzido, representada pela curva azul descontínua, é menor do que a vazão de equilíbrio do sistema, representado pela curva vermelha. Este comportamento sugere que há um potencial aumento da eficiência da produção na direção da estabilização do sistema.

Tanto os diagramas apresentados por Jansen *et al*. (1999)[51] quanto por Di Meglio (2011)[52], mostram a relação entre produção, estabilidade e variáveis operacionalmente manipuláveis de um poço de petróleo. Nestes estudos teóricos, fica evidente o potencial benéfico da estabilização do escoamento na produção dos poços, podendo gerar resultados financeiros e de segurança para as instalações.

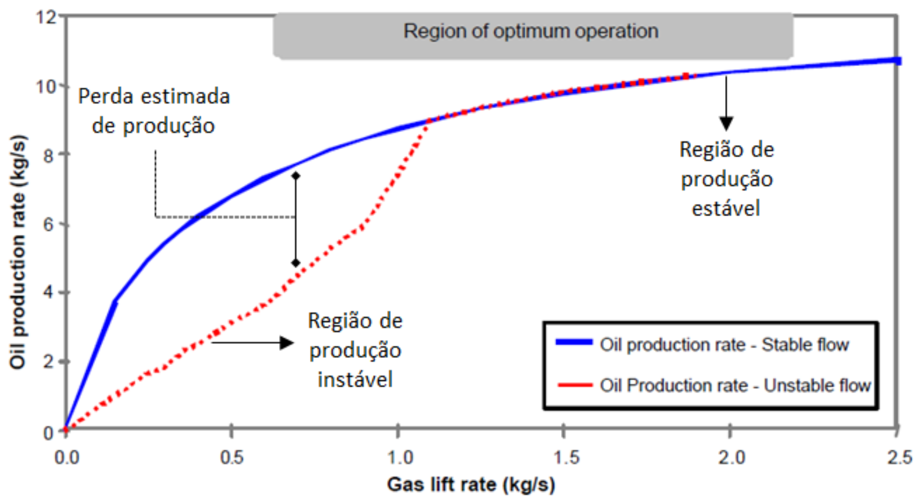

Figura 1.8 - Diagrama de bifurcação da produção de óleo em relação à vazão de *gas lift*. Baseado em Jansen *et al*. (1999)[51].

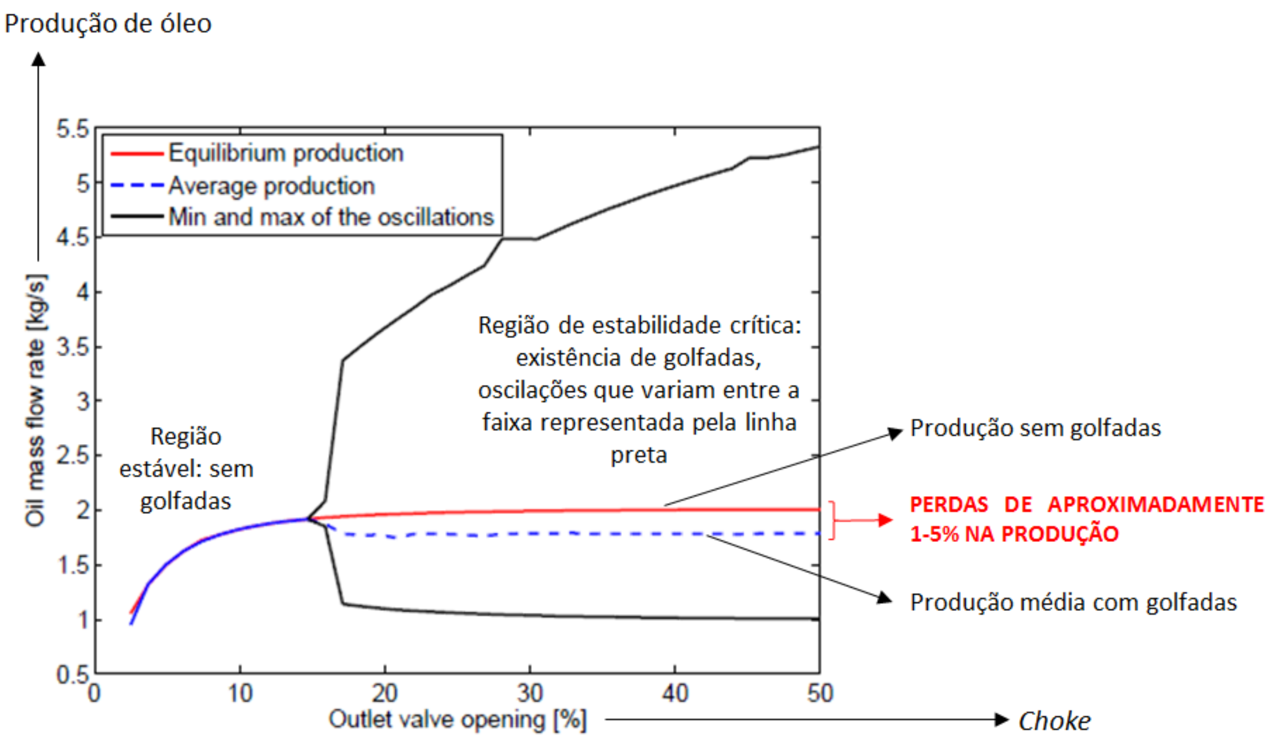

Figura 1.9 - Diagrama de bifurcação da produção de óleo em relação à abertura da *choke*. Baseado em Di Meglio (2011)[52].

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1.3 Controle da Estabilidade em Sistemas de Produção

Normalmente, na operação de um poço de petróleo com elevação tipo *gas lift*, a abertura da válvula *choke* e a vazão de gás injetado são mantidas constantes pela equipe de operação. Enquanto se busca trabalhar com a válvula *choke* o mais aberto possível, a vazão de *gas lift* é determinada pela equipe de engenharia de elevação e escoamento. Não é raro que a vazão de gás disponível seja limitada pela máxima pressão obtida pela planta de compressão.

À medida que um campo de petróleo vai se tornando maduro, o reservatório perde pressão, a quantidade de água produzida aumenta e por vezes também a viscosidade do líquido produzido devido à formação emulsões, por conta do cisalhamento que a água e o óleo são submetidos do reservatório às instalações de superfície. Estas condições aumentam a probabilidade de que os poços comecem a golfar. Dependendo do nível das oscilações é possível conviver com as golfadas sem grandes problemas operacionais. Contudo, quando a intensidade das oscilações se torna um risco potencial às instalações de superfície as ações tomadas costumam ser o aumento da vazão de *gas lift* e o fechamento parcial da válvula *choke*. Conforme apresentado nos diagramas da Figura 1.8 e 1.9, estas ações aumentam a estabilidade do escoamento, mas não necessariamente são garantias de estabilidade, além de que conduzem o poço para regiões de operação subótimas[42].

Se a causa raiz da instabilidade for ligada à presença de emulsões no líquido produzido, podem ser adicionados desemulsificantes na coluna de produção. Como o próprio nome sugere, a sua ação está relacionada à quebra das emulsões geradas no escoamento multifásico que elevam a viscosidade do fluido. A redução da viscosidade facilita o escoamento e reduz as instabilidades. No entanto, devido à sua natureza físico-química bastante complexa e particular, que depende muito do tipo de petróleo, os desemulsificantes nem sempre tem resultados positivos, além de adicionar custos à operação e aumento da logística de transporte e armazenamento de produtos químicos, que é um problema corriqueiro em unidades *offshore*.

Ao conjunto de métodos para eliminação de instabilidades baseados em mudanças físicas no sistema de produção, dá-se o nome de controle passivo de golfadas. Segundo Pedersen *et al*. (2016)[53], o controle passivo de golfadas pode ser dividido em três principais agrupamentos: (1) redução do diâmetro da linha de produção; (2) criação de múltiplos *risers*; (3) instalação de dispositivos de mistura para evitar a estratificação do fluxo. As desvantagens destes métodos são inúmeras. Para as soluções classificadas como (1) surgem problemas ligados à passagem de *pig* e redução na vazão da produção; as soluções (2) apresentam CAPEX (*Capital Expenditure*) proibitivo, principalmente em instalações em lâminas d’água profundas e ultra profundas, indo inclusive na contramão dos projetos modernos que por vezes costumam adotar *manifolds* submarinos de *gas lift* e poços produtores para redução de custos com linhas; e finalmente, o conjunto (3) gera emulsões estáveis, o que torna muito difícil o processamento das fases no *topside*.

Métodos de eliminação de instabilidades através de técnicas atuação em elementos finais de controle são classificados como controle ativo de golfadas. Os primeiros estudos teóricos desta abordagem para poços de petróleo se deram na década de 1980[54,55,56,57]. Em meados da década de 1990 e no início dos anos 2000 foram relatados os principais testes de campo de estratégias de controle em poços *offshore* disponíveis na literatura[58,59,60,61], todos em águas rasas no Mar do Norte. Nos últimos 15 anos, inúmeros trabalhos abordaram o tema controle anti-golfada[62,63,64,65,66,67,68,69,70,71,72,73], contudo as contribuições destas publicações estão exclusivamente em âmbito teórico ou foram testadas apenas em plantas experimentais. Apesar de a linha de trabalho ser promissora, visto que não apresenta as desvantagens dos métodos passivos ou da utilização de desemulsificantes, e apresentar um potencial de recuperação da produção perdida devido às golfadas, há poucos registros de aplicações em campo. Além disso, os cenários de águas profundas e ultra profundas, que compõem a maioria das novas descobertas no mundo, são pouco abordados na maioria dos trabalhos da literatura.

1.4 Objetivos e Estruturação do Trabalho

Apesar do problema de estabilidade em escoamento multifásico ser um tema de estudo e pesquisa desde a década de 70, abordado majoritariamente pela indústria do petróleo, poucos relatos de aplicações em sistemas reais são encontrados na literatura. Quando estes relatos estão disponíveis, as informações e os detalhes das implementações são significantemente simplificados.

Sendo assim, este trabalho busca explorar ferramentas de controle de processos em sistemas de produção de petróleo com problemas de ciclo limite, com o objetivo de gerar implementações aplicáveis em sistemas de escala industrial. O foco do trabalho são instalações de produção localizadas em ambiente *offshore*, mais especificamente em águas profundas e ultraprofundas. Os objetivos específicos (O_n) são apresentados a seguir:

- O_1 Propor modelo simplificado adequado à operação em ambiente marítimo;
- O_2 Propor novas estratégias de controle de golfadas;
- O_3 Avaliar controle preditivo em poços de petróleo;
- O_4 Avaliar controle multivariável em poços de petróleo;
- O_5 Avaliar controle não linear em poços de petróleo;
- O_6 Implementar e validar desenvolvimentos em campo.

Neste capítulo foi feita uma introdução ao trabalho, bem como foi apresentado o seu principal objetivo, motivação e considerações relevantes.

No Capítulo 2 é feita uma avaliação de modelos dinâmicos encontrados na literatura para descrever sistemas de produção de petróleo em águas profundas e ultraprofundas. Nestes cenários, é necessário que sejam representadas as principais capacitâncias dos poços: coluna de produção, anular de *gas lift*, linha de fluxo e *riser*. Como nenhum dos modelos de parâmetros concentrados disponíveis na literatura representa o arranjo em questão, um modelo simplificado baseado no acoplamento de submodelos dos sistemas supracitados foi proposto. O modelo resultante é composto por um sistema de equações algébrico-diferenciais chamado de FOWM (*Fast Offshore Wells Model*), devido à baixa rigidez numérica verificada na sua integração. Avaliado frente a modelos comerciais considerados rigorosos e a dados operacionais de poços reais, o modelo FOWM mostrou capacidade de representar singularidades e ciclos limite tipicamente verificados em sistemas de escoamento multifásico na indústria do petróleo.

O Capítulo 3 descreve uma estratégia de controle que aborda aspectos normalmente não explorados em casos de poços de petróleo: controle preditivo e multivariável do sistema. O problema da produção de petróleo envolve variáveis como a vazão de *gas lift* injetado no poço, a contrapressão da linha de produção, induzida pelas válvulas *choke*, e eventualmente a injeção de desemulsificantes para redução da viscosidade do líquido produzido. As estratégias de controle reportadas na literatura costumam considerar o sistema monovariável e levam em conta apenas a válvula *choke* como variável manipulada. Com a finalidade de considerar a natureza multivariável do problema, este capítulo explora a utilização da válvula *choke* e da vazão de *gas lift* de modo integrado por um controlador preditivo não linear. O controlador faz uso do modelo FOWM, apresentado no capítulo anterior, para predizer o comportamento dinâmico do poço. Os resultados mostram ser possível estabilizar e otimizar a produção através do controle da pressão de fundo do poço. Além disso, a estratégia de controle permitiu a utilização de válvulas *choke* como variável manipulada, mesmo com atuadores lentos, como os de passo, tipicamente encontrados em unidades de produção de petróleo.

No Capítulo 4 é apresentada a aplicação de uma estratégia de controle avançado em um poço de petróleo real da Petrobras. A estratégia é estruturada no acoplamento de um controlador preditivo com outro puramente baseado em retroalimentação. A finalidade deste sistema de controle é permitir a estabilização do escoamento através da ação na válvula *choke* de superfície e, desta forma, possibilitar a redução da pressão de fundo do poço, que produz um efeito de aumento direto nas vazões de líquido e gás produzidos. Como resultado da aplicação, foi possível aumentar em 10% a produção do poço.

No Capítulo 5 é discutido o problema da não linearidade dos poços de petróleo e seu efeito na redução da robustez das estratégias de controle linear. Uma metodologia para compensação desta não linearidade é proposta a partir de um modelo semiempírico. A proposta foi aplicada em campo e os resultados obtidos permitiram o aumento consistente na produção do poço de até 9%.

Por fim, são apresentadas as principais conclusões obtidas no decorrer do trabalho, bem como as etapas planejadas para a conclusão desta tese.

Os objetivos específicos listados anteriormente e as contribuições (C_n), descritas a seguir, são correlacionados pelo diagrama gráfico da Figura 1.10.

- C_1 Mapeamento de modelos dinâmicos de sistemas de produção de petróleo *offshore* baseados em equações diferenciais ordinárias (EDO);
- C_2 Desenvolvimento de modelo dinâmico de poços de petróleo, com elevação tipo *gas lift*, para ambientes de produção em águas profundas e ultraprofundas;
- C_3 Metodologia de ajuste de modelo para sistemas com ciclo limite;
- C_4 Validação/identificação de modelos com dados reais;
- C_5 Avaliação da dinâmica de sistemas reais;
- C_6 Levantamento de estado da arte do controle ativo de golfadas;
- C_7 Avaliação de controle preditivo para poços com ciclo limite;

- *C_8* Avaliação de controle multivariável em poços com elevação tipo *gas lift*;
- *C_9* Avaliação de controle não linear em poços de produção de petróleo;
- *C_{10}* Implementação em campo.

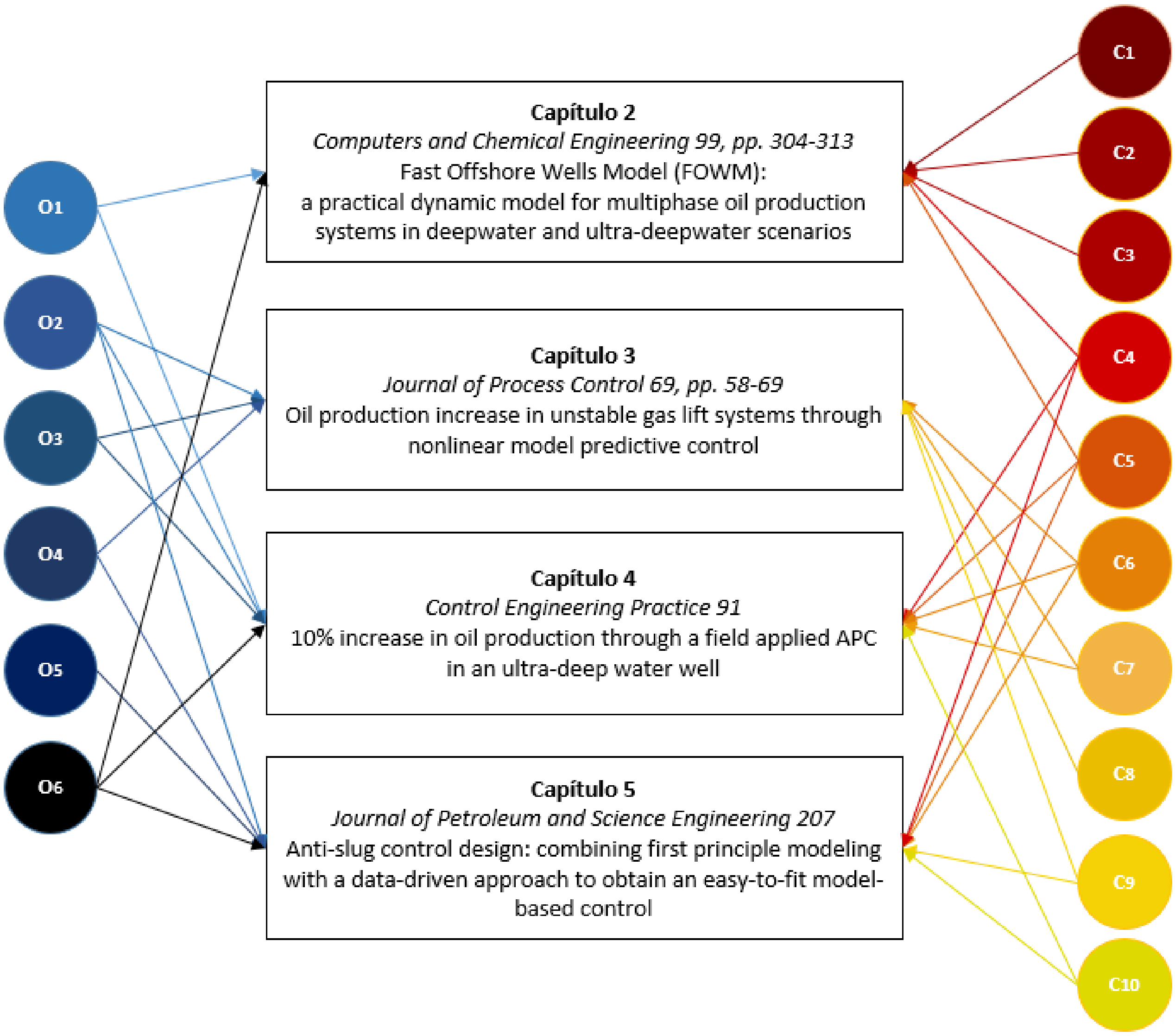

Figura 1.10 - Diagrama gráfico da tese.

1.5 Produção Técnica e Contribuições

Os capítulos que compõem esta tese estão publicados em jornais científicos, além de algumas publicações já realizadas em congressos nacionais.

Capítulo 2 Diehl F.C., Anzai T.K., Almeida C.S., Von Meien O., Neto S.S., Rosa V.R., Campos M.C.M.M., Reolon F., Gerevini G., Ranzan C., Farenzena M. and Trierweiler J.O., 2017. *Fast Offshore Wells Model (FOWM): A practical dynamic model for multiphase oil production* *systems in deepwater and ultra-deepwater scenarios*. Computers and Chemical Engineering 99, pp. 304-313. https://doi.org/10.1016/j.compchemeng.2017.01.036

Capítulo 3 Diehl F.C., Almeida C.S., Anzai T.K., Gerevini G., Neto S.S., Von Meien O.F., Campos M.C.M.M., Farenzena M., Trierweiler J., 2018. *Oil Production Increase in Unstable Gas Lift System Through Nonlinear Model Predictive Control*. Journal of Process Control 69, pp. 58-69. https://doi.org/10.1016/j.jprocont.2018.07.009

Capítulo 4 Diehl F.C., Machado T.O., Anzai T.K., Almeida C.S., Moreira C.A., Nery G.A., Campos M.C.M.M., Farenzena M., Trierweiler J., 2018. *10% Increase in Oil Production Through a Field Applied APC in an Ultra-Deepwater Well*. Control Engineering Practice 91. https://doi.org/10.1016/j.conengprac.2019.104108

Capítulo 5 Diehl F.C., Gerevini G., Machado T.O, Quelhas A.D., Anzai T.K., Bitarelli T., Serpentini F., Azambuja J.R.F., Jahanshahi E., Skogestad S., Farenzena M., Trierweiler J., 2021. *Anti-slug control design: combining first principle modeling with a data-driven approach to obtain an easy-to-fit model-based control*. Journal of Petroleum and Science Engineering 207. https://doi.org/10.1016/j.petrol.2021.109096

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Capítulo 2

Fast Offshore Wells Model (FOWM): A practical dynamic model for multiphase oil production systems in deepwater and ultra-deepwater scenarios

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Abstract

This work describes a simplified dynamic model for control and real time applications in offshore deepwater and ultra-deepwater petroleum production systems. Literature about simplified dynamical models, capable of cover the global architecture of an offshore multiphase production system, is scarce. Hence, the proposed model integrates and adapts partial models available in the literature in order to generate a single model of the whole system. The model, designed to represent slugs generated by the casing heading and terrain/riser concomitantly, was evaluated by comparison with a traditional commercial simulator and was also implemented in two actual production systems. As a result, the model showed the capability of capturing complex dynamical behaviors, such as limit cycles, demonstrated to be numerically more stable than similar models in literature, fast enough to be used in real time applications and proved to be adherent to the commercial simulator and actual operating data from Petrobras production systems.

Keywords: *Simplified multiphase dynamic model, severe slug flow, limit cycle, oil and gas production system, offshore*.

2.1 Introduction

The oil and gas industry deals with massive financial resources, both in terms of investment and revenue. In general, the upstream activity contributes more significantly to the profit of the entire oil and gas business. Hence, small increments in production efficiency can result in substantial financial returns. One way to achieve this target is to improve the operating performance of the production system by intensifying the real time applications of monitoring, control, and optimization tools, which require models to predict some key variables or estimate non-available ones. Additionally, the system dynamic must be incorporated into these models, especially taking into consideration the complex dynamic behavior usually presented by oil production systems.

A common feature in oil production is the flow irregularities during fluid transportation from the reservoir to the surface facilities. The main problems caused by flow instabilities are linked to the increase of operational risk, reduction of the production system availability, and difficulties in leading the wells to ideal operational conditions. If the oil rig is located in offshore environment, the flow problems become even more critical. In deepwater and ultra-deepwater production, the set well-flowline-riser is composed of long pipes distributed in various angles. This distribution may create instabilities in the multiphase flow, named terrain or riser induced slugging, resulting in operational risks and production decreases[1,2,3,4]. Besides, the gas lift system can generate limit cycles by itself, known as casing heading, resulting in similar problems as previously mentioned[5,6,7,8].

Improving this operation could be a key point to optimizing the production system's profit. To achieve this goal, efforts should be concentrated on providing better operation of the production system, increasing the monitoring, control, and real time knowledge, in order to support fast decisions about the operation. This work aims to contribute to this goal by proposing an integrated simplified dynamic model for a typical oil and gas production system in deepwater and ultra-deepwater fields. In this sense, a fast model that includes the whole arrangement of the system is desirable. In other words, the model needs to describe pressures and flow rates at the well, flowline, and riser in strategical points.

Usually in rigorous dynamic multiphase flow modeling, distributed parameter models depicting spatial variations in the states within the control volume are commonly described through partial differential equations (PDE). Several multiphase flow models based on PDE are proposed in literature[9,10,11,12,13]. PDE models are commonly used in commercial simulators, however there are two major drawbacks in these simulators: licensing cost and long computational time. For instance, the high computational demand is a limiting factor when the purpose is control and real time optimization. In terms of computing performance, the most appropriate models are those known as lumped parameters, which are described by a set of ordinary differential equations (ODE). These models are referred to as simplified models. Such models describe the system with several simplifying considerations, usually neglecting the conservation of momentum and energy, keeping only the mass conservation of the control volume.

So far, the main contributions to the ODE models for oil production are those developed to model the coupling of the production column and the gas lift annular[14,15]; those proposed to model the flowline and riser[4,16]; and one proposal considering the well, the flowline and the riser[17]. From the perspective of the offshore system's architecture, the most comprehensive model is the last one[17], although it does not model the annular gas lift flow and shows some difficulties in numerical terms. Furthermore, current models assume a constant or linear flow rate between the reservoir and the well, which can be a rough approximation if the objective is production optimization. Other models[18,19,20,21,22,23] are also available in the literature, however most of these works are previous development of those quoted above. In the literature, simplified dynamical models for a typical well which is composed of a reservoir, production column, gas lift annular, and subsea pipeline that allows pressures and flows estimation at key points with good numerical behavior are unavailable. Another important point is the kind of slug the models are able to describe. The most impactive slugs are formed at the annular gas lift (casing heading) and by the topography of the seabed (terrain/riser). There are no ODE simplified models available in the literature capable of describing both slugging mechanisms simultaneously. Theoretically, models from Eikrem et al. (2008)[14] and Jahanshahi et al. (2012)[15] can describe casing heading slugs, while the models from Meglio (2011)[4], Jahanshahi and Skogestad (2011)[16] and Jahanshahi (2013)[17] can describe terrain/riser slugs. Thus, there is a lack of a simplified model to characterize both the main slug mechanisms at the same time. Furthermore, the model's accession is usually little explored, and the results are typically based on few operational points. Additionally, very few works have been tested in real industrial cases, which is a crucial point to evaluate the quality of the models.

This paper presents a simplified model for multiphase production systems, named Fast Offshore Wells Model (FOWM), based on joint and slight modification of literature’s models. The model consists of an ODE set considering the riser, flowline, production column and gas lift annular, nonlinear reservoir model based on Vogel[24], and a representation of the flow rate and pressure in typical instrumentation points: at the bottom of the production column, PDG (Permanent Downhole Gauge), at the Christmas-Tree (Xmas-Tree or X-Tree), TPT (Temperature/Pressure Transducer), and at the topside connection between the riser and the process plant. Due to its nature, this model can describe casing heading and terrain/riser slugs at the same time. The FOWM evaluation showed fast computational performance and appropriated adherence to reference data. The model was performed in two real wells and the results obtained were satisfactory in representing limit cycles. Furthermore, the model was implemented in three environments: Matlab, Python and C. The results showed in this paper were generated by Matlab codes, whereas the implementation in C was required to include the FOWM in a nonlinear predictive controller. The controller issue will be addressed in a future work.

Table 2.1 shows some practical characteristics of the main models[4,14,15,16,17] previously cited, including the FOWM. As it can be seen, the FOWM is the most appropriate model for real applications in offshore environment.

2.2 Modelling Approach

The modeling approach developed during this study was based on the coupling of available models in the literature, in order to obtain a single unified model. Some subsequent adjustments were necessary so that the model could adequately represent a typical deepwater or ultra-deepwater production system using gas lift. Thus, the production system was divided into three main parts: the reservoir, the well, and the subsea production line. The well’s input stream, which covers the reservoir interface with the bottom hole of the production column, is represented by Vogel[24]. This model is an appropriate approach for a reservoir with associated gas, allowing the nonlinear prediction of the produced flow rate to be based on the pressure gradient between the bottom hole of the well and the reservoir. The mass balances for the well are based on two works from the literature[14,15], and represent the production column and the annular gas lift section. The production line, composed by the flowline and riser, is based on an indexed virtual valve[4] at a point of severe slugging formation and intends to represent the instabilities of the flow, especially the ones caused by the terrain topography or by the riser plugging.

Table 2.1. Comparing the newest literature simplified models for oil production system.

	Meglio (2011)	Eikrem et al. (2008)	Jahanshahi et al. (2012)	Jahanshahi and Skogestad (2011)	Jahanshahi (2013)	FOWM
Reservoir	No	Linear	Linear	No	Linear	Nonlinear
Tubing	No	Yes	Yes	No	Yes	Yes
Gas Lift Annular	No	Yes	Yes	No	No	Yes
Flowline/Riser	Yes	No	No	Yes	Yes	Yes
Pressure estimation on PDG	No	No	No	No	No	Yes
Pressure estimation on TPT	Yes	No	No	Yes	Yes	Yes
Represent casing heading	No	Yes	Yes	No	No	Yes
Represent terrain/riser induced slugging	Yes	No	No	Yes	Yes	Yes
Numerical Stiffness	No	No	-	-	Yes	No
Validation with industrial data	Yes	No	No	No	No	Yes

The combination of these three sections in a single model has resulted in the ODE system, given by Equation (2.1)-(2.6), which can simultaneously describe casing heading[5,6,7,8,14,15] and terrain/riser[1,2,3,4,16,17] slugs. To the authors' knowledge, this is the first simplified model that combines a complete production system setup, (i.e., reservoir + production column + gas lift annular + flowline + riser). Due to its features and applicability, the model was named Fast Offshore Wells Model (FOWM). The FOWM is based only on mass conservation equations. Figure 2.1 helps to understand the proposed arrangement.

$$\frac{dm_{ga}}{dt} = W_{gc} - W_{iv} \tag{2.1}$$

$$\frac{dm_{gt}}{dt} = W_r \alpha_{gw} + W_{iv} - W_{whg} \tag{2.2}$$

$$\frac{dm_{lt}}{dt} = W_r (1 - \alpha_{gw}) - W_{whl} \tag{2.3}$$

$$\frac{dm_{gb}}{dt} = (1 - E) W_{whg} - W_g \tag{2.4}$$

$$\frac{dm_{gr}}{dt} = E\, W_{whg} + W_g - W_{gout} \tag{2.5}$$

$$\frac{dm_{lr}}{dt} = W_{whl} - W_{lout} \tag{2.6}$$

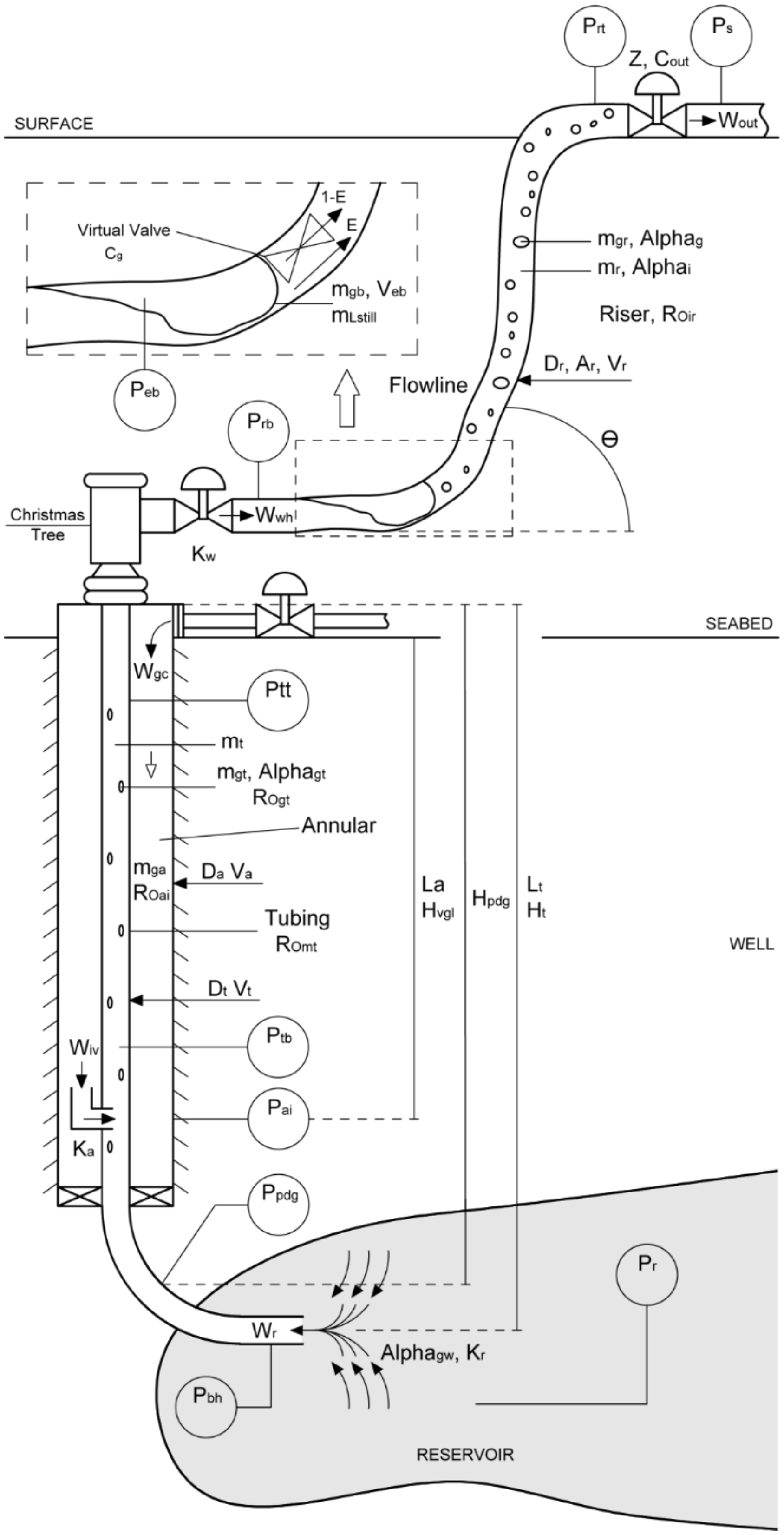


Figure 2.1. Offshore oil and gas production system modeled by FOWM.

In the FOWM, the states represent the mass of gas and liquid in different sections of the system: m_{ga} is the gas mass in the annular, m_{gt} is the gas mass in the production column or tubing, m_{lt} is the mass of liquid in the tubing, m_{gb} is the mass of gas in the bubble at the subsea production line, m_{gr} and m_{lr}, respectively, are the gas and liquid mass in the set flowline/riser. E is the mass fraction of gas that bypasses the bubble in the subsea pipeline and α_{gr} is the mass gas fraction at reservoir's pressure and temperature reservoir conditions.

The fluid flows used in the model are obtained by the following equations:

$$W_{iv} = K_a\sqrt{\rho_{ai}(P_{ai} - P_{tb})} \tag{2.7}$$

$$W_r = K_r\left[1 - \left(0{,}2\frac{P_{bh}}{P_r}\right) - \left(0{,}8\frac{P_{bh}}{P_r}\right)^2\right] \tag{2.8}$$

$$W_{whg} = K_w\sqrt{\rho_L(P_{tt} - P_{rb})}\alpha_{gt} \tag{2.9}$$

$$W_{whl} = K_w\sqrt{\rho_L(P_{tt} - P_{rb})}(1 - \alpha_{gt}) \tag{2.10}$$

$$W_g = C_g(P_{eb} - P_{rb}) \tag{2.11}$$

$$W_{gout} = \alpha_g C_{out} z\sqrt{\rho_L(P_{rt} - P_s)} \tag{2.12}$$

$$W_{lout} = \alpha_l C_{out} z\sqrt{\rho_L(P_{rt} - P_s)} \tag{2.13}$$

where W_{gc} is the gas lift mass flow entering the annular, W_{iv} is the gas mass flow from the annular to the tubing, W_r is the reservoir to the bottom hole flow estimated by the Vogel equation[24], W_{whg} and W_{whl} are the gas and liquid mass flows at the Christmas Tree, that were modeled as a valve by the Equation 2.9 and 2.10, W_g is the flow at the virtual valve, and W_{gout} and W_{lout} are the gas and liquid flow through the topside choke valve. K_a, K_r and K_w are the flow coefficient between the annular and the tubing, the Vogel parameter that is directly proportional to the production of the reservoir to the tubing and the flow coefficient at the Christmas Tree, respectively.

The gas density in the annular ρ_{ai} is given by Equation 2.14, as ρ_L is the liquid density assumed as a constant in FOWM. As shown in Equation 2.15 to 2.17, α_{gt} is the gas mass fraction in the tubing, while α_{gr} and α_{lr} are the gas and liquid mass fractions in the subsea pipeline. The virtual valve[4] and choke valve constants are represented as C_g and C_{out}. The choke opening fraction is given by z. P_r and P_S are the pressures surrounding the production column bottom hole and at the gravitational separator in the process plant facilities.

The other pressures in Equation 2.7 to 2.13 are described in Equation 2.18 to 2.25. From the top of the tubing to the gas lift injection point the pressures are calculated similarly to the Eikrem model. Bellow the gas lift injection point, the multiphase fluid density at reservoir is used instead the oil density and an extra equation to estimate pressures at PDG location is included.

$$\rho_{ai} = \frac{MP_{ai}}{RT} \tag{2.14}$$

$$\alpha_{gt} = \frac{m_{gt}}{m_{gt} + m_{lt}} \tag{2.15}$$

$$\alpha_{gr} = \frac{m_{gr}}{m_{gr} + m_{lr}} \tag{2.16}$$

$$\alpha_{lr} = 1 - \alpha_{gr} \tag{2.17}$$

$$P_{ai} = \left(\frac{R\,T}{V_a M} + \frac{g\,L_a}{V_a}\right) m_{ga} \tag{2.18}$$

$$P_{tb} = P_{tt} + \rho_{mt} g H_{vgl} \tag{2.19}$$

$$P_{bh} = P_{pdg} + \rho_{mres} g(H_t - H_{pdg}) \tag{2.20}$$

$$P_{pdg} = P_{tb} + \rho_{mres} g(H_{pdg} - H_{vgl}) \tag{2.21}$$

$$P_{tt} = \frac{\rho_{gt} RT}{M} \tag{2.22}$$

$$P_{rb} = P_{rt} + \frac{(m_{lr} + m_{L,still}) g \sin(\theta)}{A_{ss}} \tag{2.23}$$

$$P_{eb} = \frac{m_{gb} RT}{MV_{eb}} \tag{2.24}$$

$$P_{rt} = \frac{m_{gr} RT}{M(\omega_u V_{ss} - \frac{m_{lr} + m_{L,still}}{\rho_l})} \tag{2.25}$$

where P_{ai} is the pressure in the annular gas injection point to the tubing, P_{tb} is the pressure in the gas injection point on the tubing side, P_{bh} is the pressure in the bottom hole, P_{pdg} is the pressure at the PDG position, P_r is the reservoir pressure surrounding the bottom hole, P_{tt} is the pressure at the top of the tubing, P_{rb} is the pressure at the flowline before the bubble position, P_{eb} is the bubble pressure, and P_{rt} is the pressure at the top of the riser. The estimated gas properties consider the gas behavior as being ideal; T is an average temperature in the production system, M is the gas molecular weight, R is the universal gas constant, and g is the gravity acceleration. V_a is the annular volume and L_a is the annular length. The mixture density in the tubing ρ_{mt} is given by Equation 2.26, while the gas density in this section ρ_{gt} is calculated by Equation 2.27. The mixture density at the reservoir is constant and presented by ρ_{mres}. The vertical length between the Christmas Tree and the gas lift valve, the PDG transmitter, and the bottom hole are represented by H_{vgl}, H_{pdg} and H_t, respectively. The average riser inclination is given by θ. $m_{L,still}$, is the minimum mass of liquid in the subsea pipeline, and V_{eb} is the bubble volume. ω_u is an assistant parameter used to allocate the bubble whose use will be discussed hereafter. The cross-section area of the subsea pipeline A_{ss} is defined in Equation 2.29, and its volume is given by Equation 2.30. The gas lift annular volume is calculated using Equation 2.31.

$$\rho_{mt} = \frac{m_{gt} + m_{lt}}{V_t} \tag{2.26}$$

$$\rho_{gt} = \frac{m_{gt}}{V_{gt}} \tag{2.27}$$

$$V_{gt} = V_t - \frac{m_{lt}}{\rho_L} \tag{2.28}$$

$$A_{ss} = \frac{\pi {D_{ss}}^2}{4} \tag{2.29}$$

$$V_{ss} = \frac{\pi {D_{ss}}^2 L_r}{4} + \frac{\pi {D_{ss}}^2 L_{fl}}{4} \tag{2.30}$$

$$V_a = \frac{\pi {D_a}^2 L_a}{4} \tag{2.31}$$

$$V_t = \frac{\pi {D_t}^2 L_t}{4} \tag{2.32}$$

In Equation 2.26 to 2.31, V_t is the volume of the tubing section, V_{gt} is the gas volume in the tubing and L_t is the tubing length. The diameters D_{ss}, D_t and D_a are the subsea pipeline, tubing, and annular equivalent diameter section.

Nine parameters are available to fit the FOWM prediction to the reference data. The model fitting parameters, which do not necessarily have a strict real physical meaning, were described previously: $m_{L,still}$, C_g, C_{out}, V_{eb}, E, K_w, K_a, K_r and ω_u. In the original riser model[4,25,26,27], the volume of the subsea pipeline V_{ss} is defined as the part of the pipe downstream the virtual valve[27], what suggests its position could be manipulated in order to locate this valve once this point is uncertain. As the whole flowline/riser system is considered in the FOWM, the inclusion of a parameter ω_u makes the product between V_{ss} and ω_u an apparent volume that should correct the average residence time in the system. For practical purposes, the pressure preceding the bubble is the pressure near the wet Christmas Tree, where instrumented wells usually have measurements. The authors recommend starting the model tuning assuming a unitary and constant value to ω_u and use it as a last resort when the model tuning is no longer satisfactory.

The pressure drop is not included as function of velocities in the FOWM in order to keep the model simple and numerically fast. The inclusion of the velocity dependence may increase the numerical stiffness as it was experienced in a similar model from the literature[17], what would make it improper to be used in a model predictive control strategy, for instance. Thus, the pressure drop is indirectly included in the model connection elements (K_a, K_w e C_{out}) represented by flow equations.

2.3 Description of the Real System

The simplified model proposed in this work was evaluated using two sources of reference data: one from a rigorous model and another one from a real operation system. Firstly, a rigorous two-fluid model of a typical deepwater well was developed using the multiphase flow simulator OLGA[10,28]. Figure 2.2 shows the architecture of the well, named well A. The reservoir, the production column, the flowline-riser, the gas lift subsea line, and the annular of gas (involving the production column) were all considered during the modeling. The choke valve and the gas lift control valve were also included at the facilities. At the production column, the gas lift valve was considered as an orifice valve.

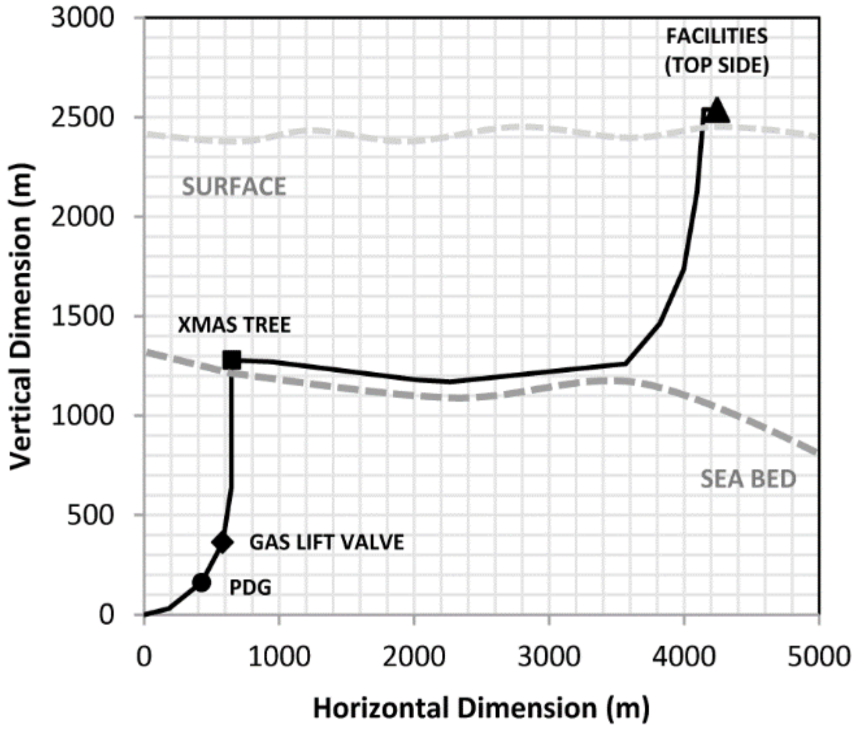


Figure 2.2. Real deepwater well A architecture.

In order to represent more accurately the reservoir behavior, a quadratic model was chosen, as shown in Equation 2.32. The parameters A, B and C are used to fit the reservoir model. Figure 2.3 presents this model applied to a real data set representing approximately one year of operation. The main idea is to capture the trend of the reservoir behavior.

$$P_{res}^{\ 2} - P_{bh}^{\ 2} = A + BW_{res} + C(W_{res})^2 \qquad (2.32)$$

$$\Phi = P_{res}^{\ 2} - P_{bh}^{\ 2} \qquad (2.33)$$

The well modeled in this section was based on a real offshore well from Petrobras. Data from the real operation of this well were used to test the adaptation capability of the FOWM. The main information about the production system is shown at Table 2.2. The well B is a second real system where the FOWM was implemented.

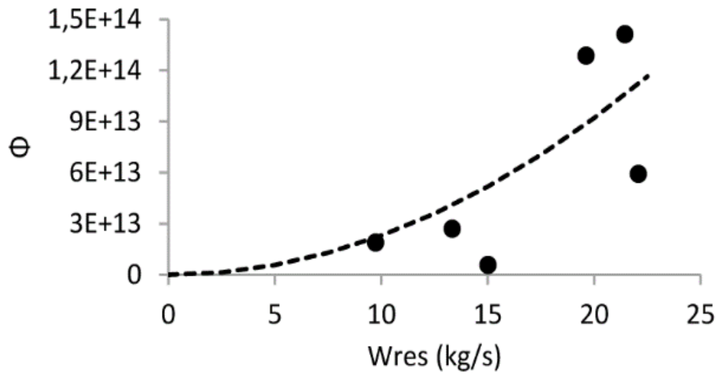


Figure 2.3. Quadratic reservoir model used in OLGA to fit actual production points.

Table 2.2. Data from real production systems.

	Well A	Well B
ρ_L (kg/m³)	900	879
P_r (bar)	225	330
P_s (bar)	10	8
α_{gw}	0.0188	0.0244
ρ_{mres} (kg/m³)	892	886
M (kg/kmol)	18	18
T (K)	298	298
L_r *(m)*	1569	1949
L_{fl} *(m)*	2928	1695
L_t *(m)*	1639	3958
L_a *(m)*	1118	2390
H_t *(m)*	1279	2884
H_{pdg} *(m)*	1117	2602
H_{vgl} *(m)*	916	1568
D_{ss} *(m)*	0.15	0.20
D_t *(m)*	0.15	0.15
D_a *(m)*	0.14	0.14

2.4 FOWM Global Fit

As previously mentioned, the FOWM was evaluated with OLGA simulations and real data sources. In order to fit the model to this data, a global unconstrained optimization[29] based on the weighted least squares problem was employed. As the model needs to fit into a limit cycle, an objective function that intends to penalize stable solutions was proposed in order to aid the algorithm to achieve good results. The objective function is shown in Equation 2.34, where *x* and *y* represent the reference data and the model output data, respectively. The sub index i is a single sample of a data set whereas j is the data set itself. M is the number of windows and N is the sample size.

$$J_s = \sum_{j=1}^{M} \frac{1}{\omega_j} \left[\frac{1}{N} \sum_{i=1}^{N} \omega_i \left(y_{j,i} - x_{j,i} \right)^2 \right] \qquad (2.34)$$

Usually, the optimization problem achieves a local minimum, where the FOWM shows a stable behavior instead of the limit cycle seen in the dataset. To avoid this pattern of solution, the parameter ω_i was included as a weight to each data point i. This variable is data reference dependent and penalizes the objective function the more distant the points are from the reference average $\bar{x}_j$, i.e., oscillatory responses will be prioritized. The standard deviation $\sigma_{j,x}$ is used to normalize ω_i.

$$\omega_i = \left(\frac{x_{j,i} - \bar{x}_j}{\sigma_{j,x}} \right)^2 \qquad (2.35)$$

Besides ω_i, the ω_j is a whole window weight and helps the model to capture the behavior direction. The ω_j weight is based on a normalized Person correlation coefficient, where $\omega_j = 1$ in case of perfect positive correlation among the reference data and the FOWM output, $\omega_j = 0.5$ means there is no correlation and $\omega_j = 0$ represent a perfect negative correlation. This term tends to benefit the capturing of the frequency and phase response.

$$\omega_j = \left(\frac{\rho_{y,x} + 1}{2} \right) \qquad (2.36)$$

The hypersurface of the optimization problem is complex and even a global algorithm might fail to find a reasonable solution if the initial guess is not properly defined. In the following a methodology to determine the initial parameters values will be presented. The required information can be provided by a rigorous simulator, design or operational data. Production tests at topside facilities may supply actual knowledge about average flowrates. These tests usually take place periodically.

The Vogel[24] parameter K_r is proportional to the production of the reservoir to the tubing. When the PDG pressure is available, the P_{bh} can be estimated by Equation 2.20. Assuming the reservoir pressure P_r as a known variable and using flowrate data W_r from a real production system test, it is possible to estimate K_r by Equation 2.37. Despite this estimation been very accurate the authors recommend inserting this parameter in the optimization mainly due to uncertainties in the P_r definition.

$$K_r = \frac{W_r}{1 - \left(0.2 * \frac{P_{bh}}{P_r} \right) - \left(0.8 * \frac{P_{bh}}{P_r} \right)^2} \qquad (2.37)$$

The flow coefficient between the annular and the tubing K_a is estimated by Equation 2.38. If only operational data are available W_{iv} might be approximated by W_{gc}. This assumption is reasonable if a period of time long enough is used, because the average between W_{iv} and W_{gc} should be the same. The pressure in the annular gas injection point to the tubing P_{ai} might be roughly estimated through the sum of the topside gas supply and the gas column weight from facilities to the annular. The pressure in the gas injection point on the tubing side P_{tb} might be approximated adding to pressure on PDG the weight column of fluid until the gas lift valve point. The ρ_{ai} is given by the Equation 2.14. Another way to estimate K_a could be using an OLGA simulation case or a real design data to define the variables in Equation2.38.

$$K_a = \frac{W_{iv}}{\sqrt{\rho_{ai} * (P_{ai} - P_{tb})}_a} \tag{2.38}$$

The flow coefficient at the X-Tree K_w is given by Equation 2.39. Neglecting the friction effects, P_{rb} may be assumed as the TPT pressure whereas P_{tt} is defined by Equation 2.22. The liquid density ρ_L is known and the average flowrate at the X-Tree is provided by a production test. These values can also be estimated using a rigorous simulation or based on the X-Tree design data.

$$K_w = \frac{W_{whg} + W_{whl}}{\sqrt{\rho_L * (P_{tt} - P_{rb})}_w} \tag{2.39}$$

An attempt to define initial values to parameters linked to the elongated bubble and the virtual valve are shown in literature[22]. While the bubble volume V_{eb} criterion involves a numerical solver, the slip inflow of gas E is dependent of the $m_{L,still}$ parameter and the virtual valve coefficient C_g is a guess. Besides, the literature criterion to define a value to V_{eb} is the exact Hopf bifurcation position, which is not an absolute truth since Hopf point also is influenced by other parameters. Although the results using these procedures[22] might be suitable, this paper proposes an alternative method, free of numerical solver and parameter dependence. Unfortunately, the following method described is dependent of a transient rigorous simulator and C_g is a parameter based on experience fitting the model. According to Meglio et al. (2010)[27], a typical value for C_g is 10^{-4} kg.s.m^{-1}.

Firstly, it is necessary to generate a cycle of oscillation in a rigorous simulator and to monitor the gas flow at two points: the X-Tree and the topside facilities. The Figure 2.4 shows a typical behavior of one slugging cycle in the gas profile. The period between t_1 and t_2 is described as two typical phases of an unstable periodic cycle: the slug generation step and slug production step. In these phases the gas is partially blocked by the liquid plugging and the pressure continuously increases. After t_2 the decompression phase starts and this is known as bubble penetration step, followed by the gas blowdown step[3].

From the period t_1 to t_2 is possible to estimate E and V_{eb}. The slip inflow of gas is represented at the Figure 4 by the gas flow line at topside and must be calculated by Equation 2.40.

$$E = \frac{\int_{t1}^{t2} W_{gout} dt\Big|_{Topside}}{\int_{t1}^{t2} W_{whg} dt\Big|_{XTree} + \int_{t1}^{t2} W_{gout} dt\Big|_{Topside}} \tag{2.40}$$

The gas that passes through the X-Tree and does not reach the topside is accumulated in the subsea pipeline and might be regarded as the mass of gas in the elongated bubble. Assuming an average density to the gas ρ_G, it is possible to calculate V_{eb} through Equation (2.41).

One way to determine an initial value to the minimum mass of liquid in the subsea pipeline $m_{L,still}$ is available in the literature[27]. The results reported agree with the ones obtained in this paper.

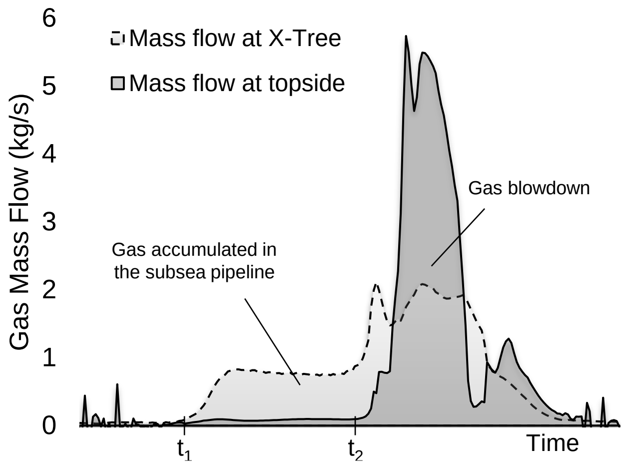


Figure 2.4. Inlet and outlet gas flowrate from the subsea pipeline estimated by OLGA.

$$V_{eb} = \frac{\int_{t1}^{t2} W_{whg} dt\Big|_{XTree} - \int_{t1}^{t2} W_{gout} dt\Big|_{Topside}}{\bar{\rho}_G} \quad (2.41)$$

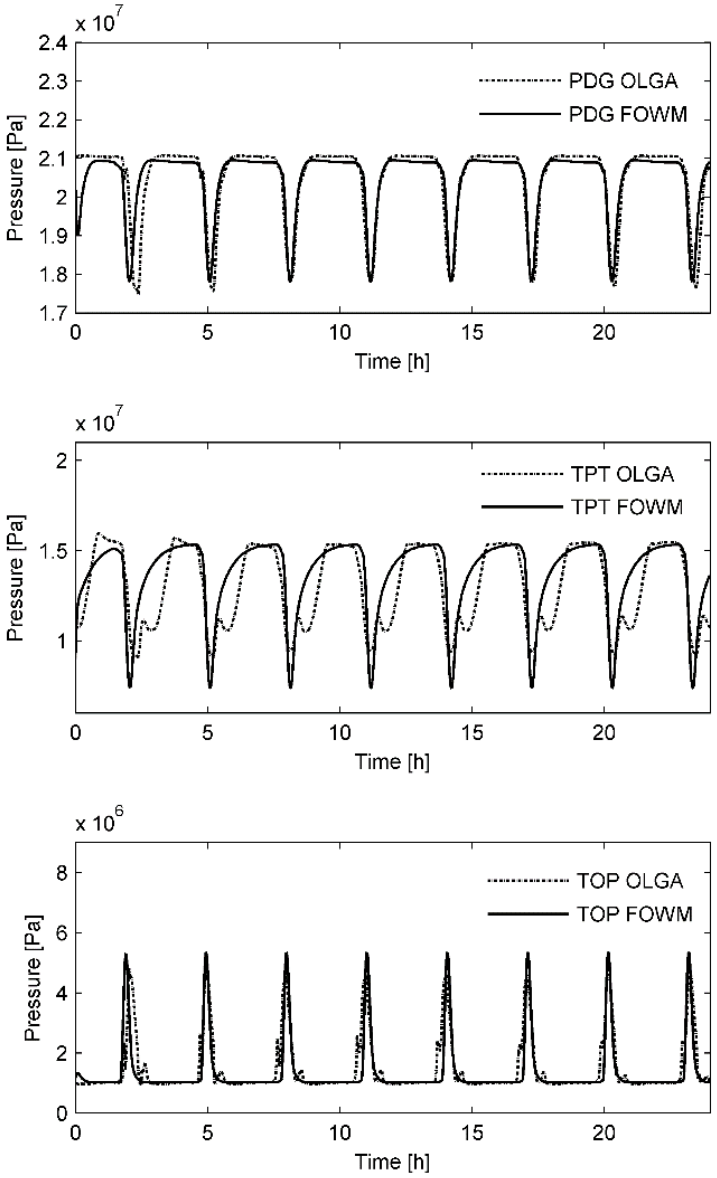
A first attempt to obtain the choke valve flow coefficient C_{out} is to use the information supplied by the equipment manufacturer. Alternatively, data from a production test can be used in the Equation 2.43 to calculate *Cout*. All information required by Equation 2.43 is provided by the production test.

$$C_{out} = \frac{W_{gout} + W_{lout}}{z * \sqrt{\rho_L * (P_{rt} - P_s)}} \quad (2.43)$$

2.5 Results and Discussion

Initially, the model quality will be illustrated using a specific operating point, as shown in Figure 2.5. The proposed model was able to adapt to the three pressures simultaneously. The FOWM's parameters are shown at the end of this section on Table 2.3. The reference data for the well, described previously in Figure 2.2, were generated by the OLGA simulator. The choke valve and the gas lift flow were kept constant so that the oscillations in the well were caused solely by a natural limit cycle. This dynamic behavior is classified as severe slugging.

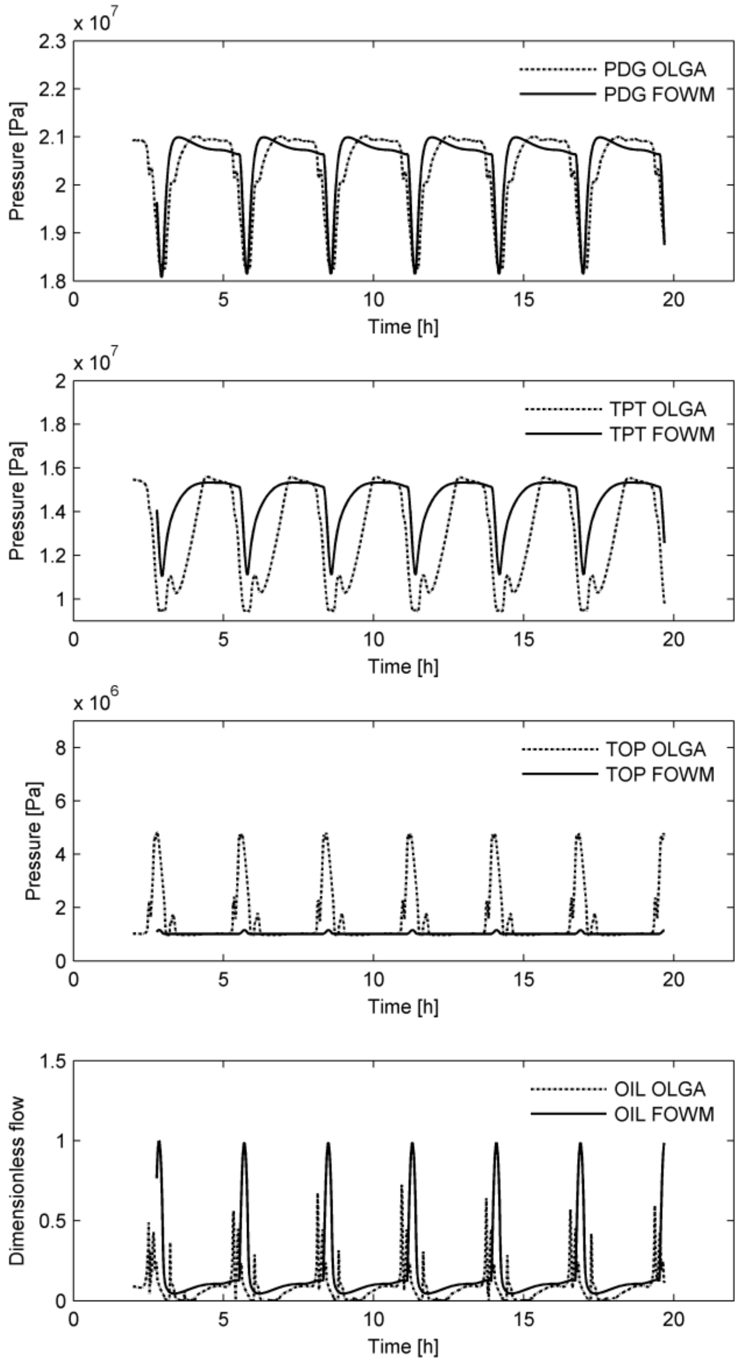
Unfortunately, in most cases, it is not possible to rely on the availability of all these measurements. Intervention costs in subsea operations are a restriction to the measuring instruments maintenance and, hence, wells frequently operate with partially functioning instrumentation. Considering this kind of limitation, it would be desirable if the model could also estimate the unavailable measurements. Thereby, the Case 2 was performed using only the PDG pressure as a reference to the FOWM tuning. The results are shown in Figure 2.5 and the FOWM's parameters are shown in Table 2.3. Figure 2.6 shows the correlation between the PDG pressure and OLGA's data. In addition, the results summarize the FOWM estimation behavior when compared to the expected outcomes. For this tuning, the TPT pressure was satisfactory estimated and the main dynamical features, such as frequency, phase and amplitude, were caught by FOWM. On the other hand, the topside pressure, TOP, estimated by FOWM, does not show a great adherence to OLGA data, indicating that the estimation problem using little information gives no guarantee about the global estimation. Despite this, the oil production flow at the topside can be well estimated by the FOWM. Oil production is presented in relative terms to the



maximum prediction of the data sets.

Figure 2.5. Case 1: FOWM adaptability to a limit cycle.

Another important feature of the model is its ability to extrapolate. In all cases presented here, the parameters of the FOWM were adjusted to one limit cycle, i.e., both the choke valve opening, and gas lift flow were kept constant at the same operating point. Thus, it is important to check how the FOWM behaves in other conditions. The diagram in Figure 2.7 shows some important features such as the Hopf bifurcation point and the oscillation amplitude. This diagram was built using the Case 2 parameters. As it can be seen, for this valve opening, the oscillation amplitudes of the OLGA and FOWM pressures are very similar. However, as the choke valve opening departs from the adjust point, there is a detachment from OLGA and FOWM data for the lower pressure values, while the estimated higher pressure remains similar. In this case, it is not a big problem in terms of calculating the pressures of PDG or TPT, since most of the time the well is maintained in the upper level of pressure, as



previously shown in Figure 2.5 and 2.6.

Figure 2.6. Case 2: FOWM predictability of pressures and oil production flow at topside.

Another feature of interest is the position of the Hopf point, in other words, where the system switches its stability. For the set of parameters used in the bifurcation diagram, the Hopf point is well captured by FOWM. It is noteworthy that the first instabilities seen in the OLGA simulation present low intensity, which means that its main origin mechanism is not a severe slug, but a different one, probably a hydrodynamic slug caused by wave formation due to the phase slip between gas and liquid. Along the choke valve opening, the intensity of the instability increases suddenly due to the severe slug formation. The model proposed in this work was designed mainly to capture severe slugging.

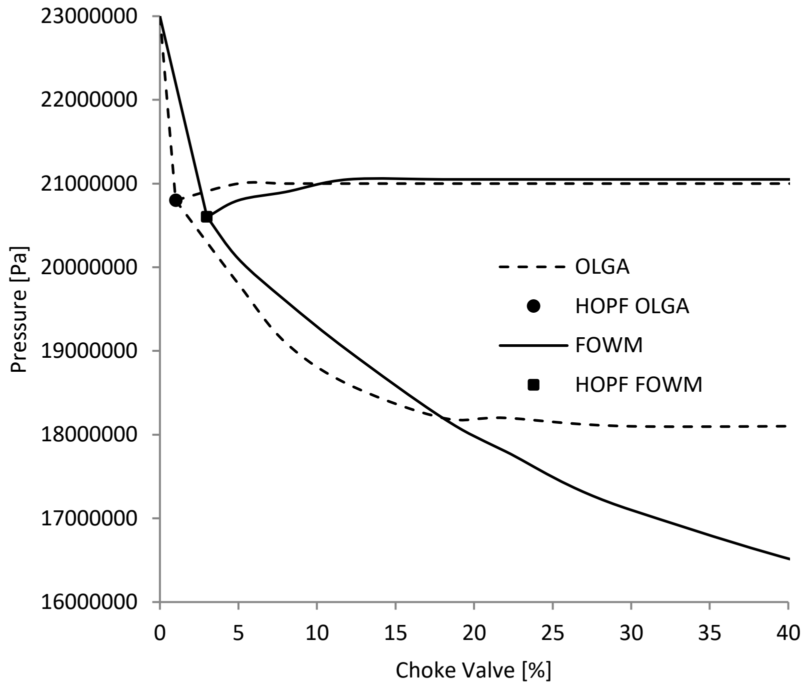


Figure 2.7. Bifurcation diagram: pressure on PDG point.

Figure 2.8 shows the FOWM behavior for different choke valve opening. In this situation the model was fitted to a single operational point, as highlighted in PDG trend. The extrapolated dynamical behavior can predict the pressures in the PDG and TPT points. This feature proves the model is not over fitted despite of its 8-9 parameters. Additionally, the FOWM shows the ability to represent the stability increase that is expected through the gas lift flow increase, as shown in Figure 2.9.

The FOWM was also applied to fit real data. The first case analyzed is the Case 3, well A (shown in Figure 2.2). Figure 2.10 shows the performance of the FOWM in the face of a real data set. The model could be adapted to a real limit cycle with good adhesion to pressures at PDG and TPT points. In this limit cycle the choke valve and the gas lift flow were kept constant. The FOWM's parameters are shown in Table 2.3.

The second implementation in an actual system, Case 4, was done at well B. This well presents different conditions of gas-oil-water in its reservoir when compared to the well A, however, their architectures are quite similar. There are three main differences between well A and B: in well B there is no flow control in the gas lift system at topside facilities; there is no TPT available at well B; and finally, well B naturally presents a more complex dynamic behavior, which means the limit cycles is not well-behaved as they are at well A.

Figure 2.11 summarizes the results of the FOWM in well B, using the parameters shown in Table 2.3. Despite the non-uniform dynamical behavior of well B, FOWM was able to predict the PDG pressure with good performance. The figure also shows how variant is the gas lift flow at topside facilities.

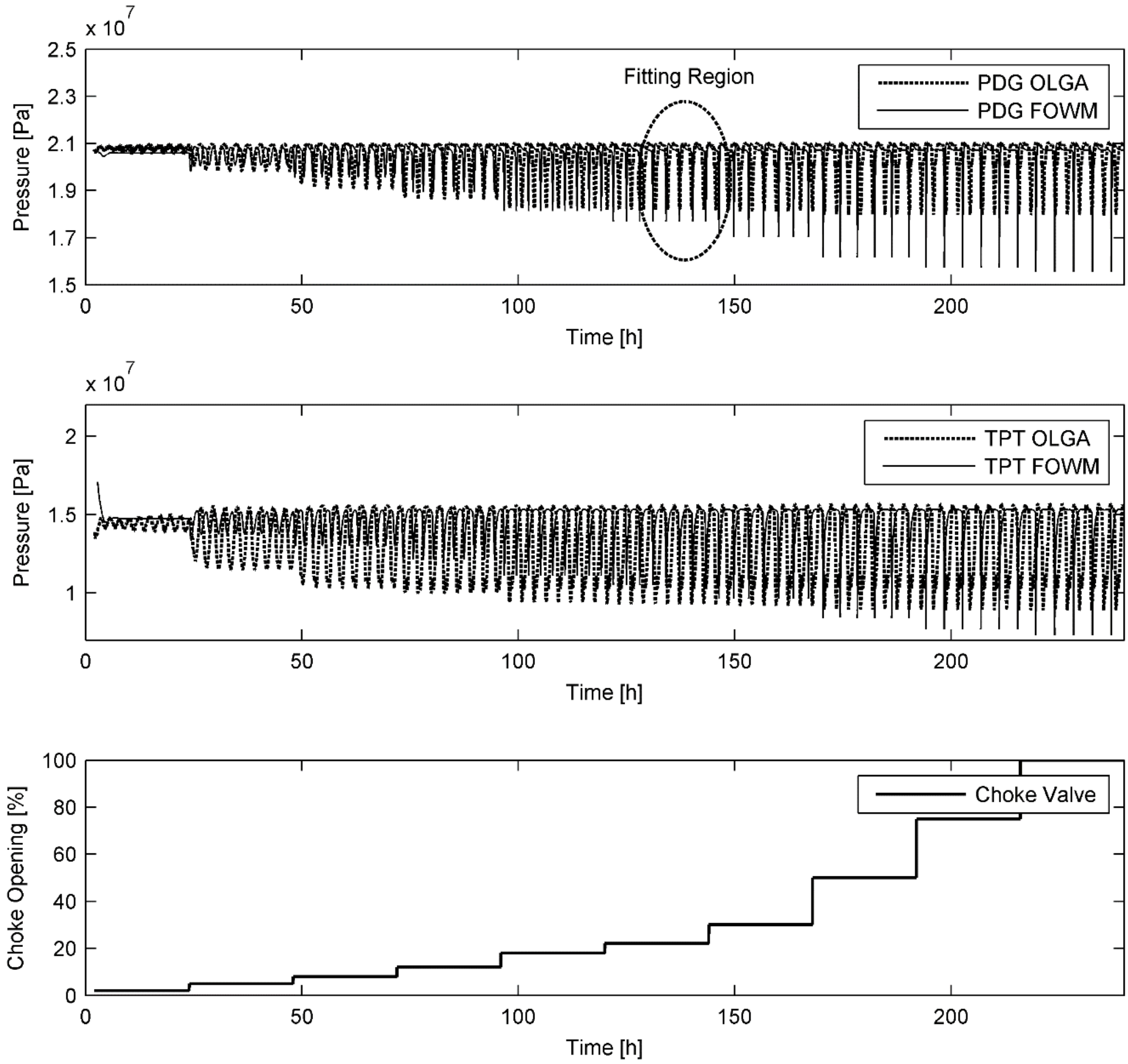


Figure 2.8. Extrapolated behavior of the FOWM for the whole choke valve opening.

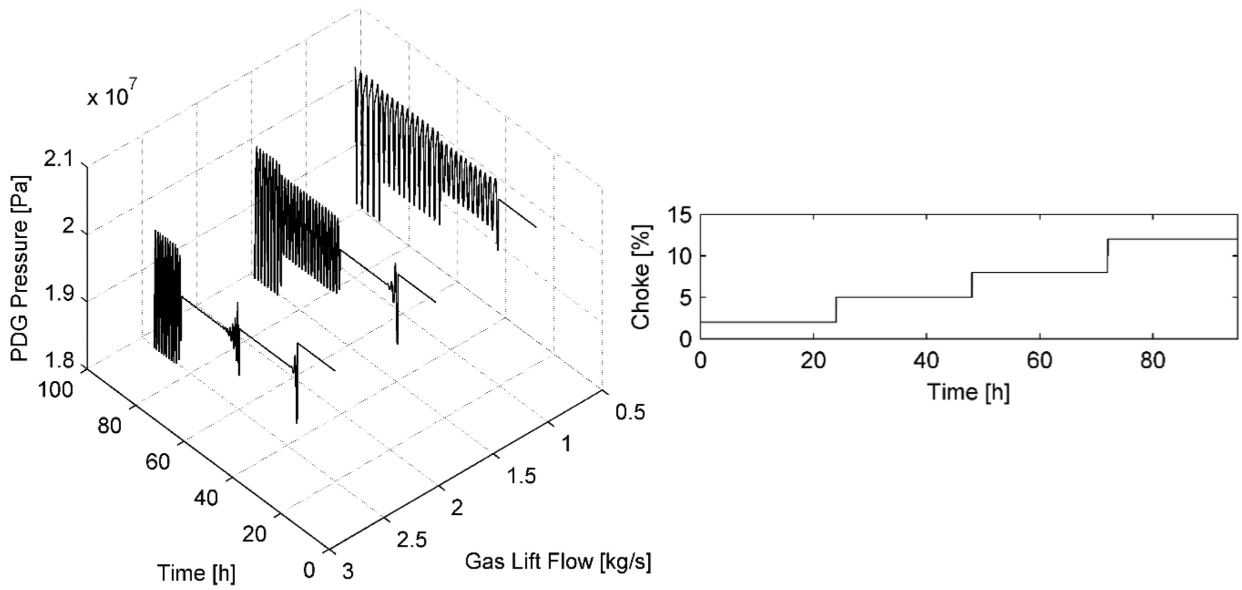


Figure 2.9. Extended behavior of the FOWM.

Table 2.3. FOWM parameters.

Parameter	Case 1 OLGA Well A	Case 2 OLGA Well A	Case 3 Real Plant Well A	Case 4 Real Plant Well B
$m_{L,still}$	$4.963e^{+2}$	$1.957e^{+3}$	$6.222e^{+1}$	$2.143e^{+4}$
C_g	$2.014e^{-4}$	$2.054e^{-4}$	$1.137e^{-3}$	$4.067e^{-4}$
C_{out}	$6.701e^{-3}$	$1{,}968e^{-2}$	$2.039e^{-3}$	$5.076e^{-2}$
V_{eb}	$1.152e^{-2}$	$8.351e^{+1}$	$6.098e^{+1}$	$9.576e^{+1}$
E	$4.035e^{-2}$	$5.714e^{-1}$	$1.545e^{-1}$	$8.340e^{-1}$
K_w	$1.337e^{-3}$	$8.679e^{-4}$	$6.876e^{-4}$	$2.199e^{-2}$
K_a	$1.817e^{-4}$	$1.591e^{-4}$	$2.293e^{-5}$	$2.922e^{-3}$
K_r	$2.578e^{+2}$	$1.313e^{+2}$	$1.269e^{+2}$	$5.000e^{+2}$
ω_u	$1.000e^{0}$	$7.650e^{0}$	$2.780e^{0}$	$1.000e^{0}$

In all the cases described in this paper, FOWM exhibited numerical stability and high speed when compared to a rigorous model like OLGA. It is possible to run hours of real time in a few seconds using the FOWM. Therefore, the model proposed here can contribute to several aspects of the oil production, including real time monitoring, control and optimization.

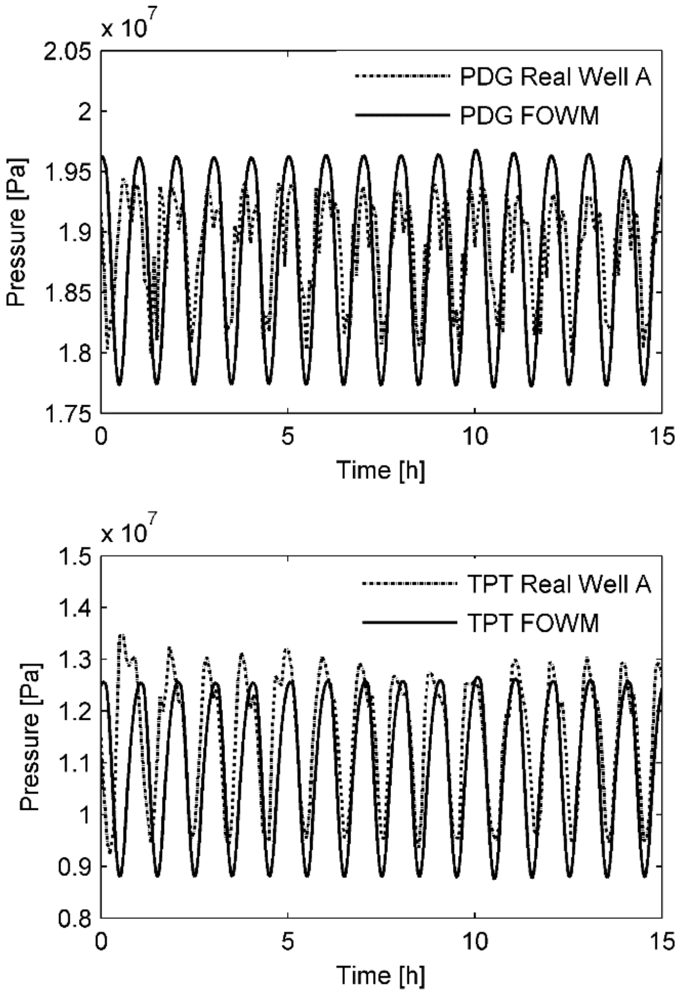


Figure 2.10. Case 3: FOWM performance in the real Well A.

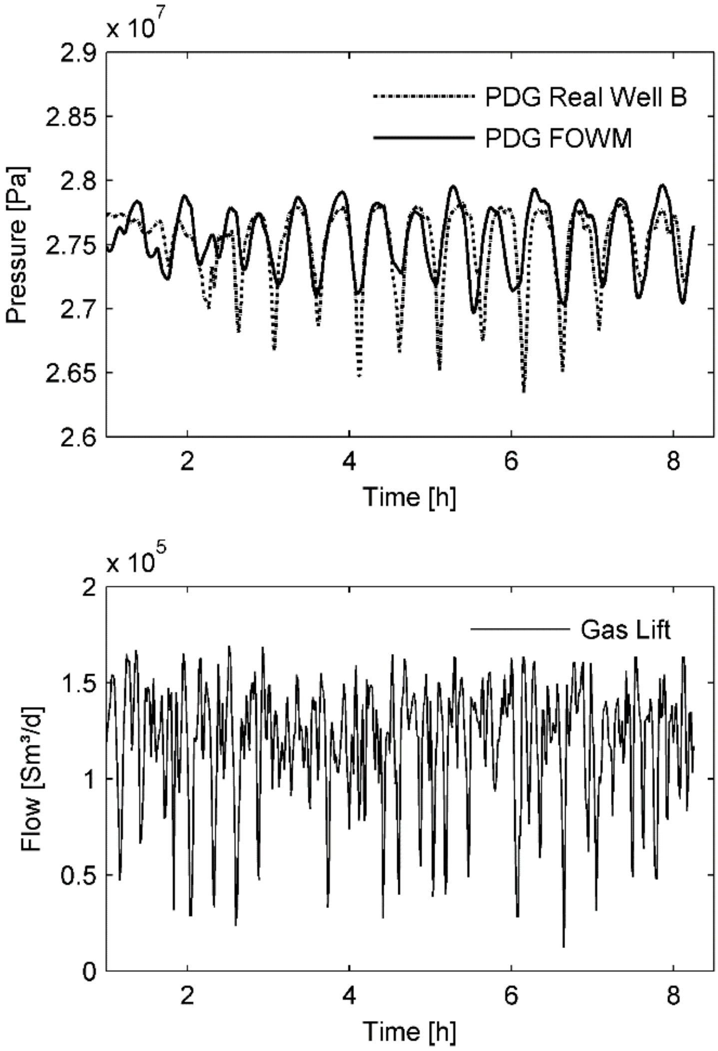


Figure 2.11. Case 4: FOWM performance in the real Well B.

2.6 Conclusion

The model proposed in this work, named the Fast Offshore Wells Model (FOWM), can represent the global architecture of an offshore production system in deepwater or ultra-deepwater scenarios, which include the riser, the flowline, the production column, the gas lift annular and the reservoir. As its name suggests, the model is fast enough to be used in process control, optimization, and real time applications. This means that the model is "soft" and has no numerical stiffness, which allows the implementation of various simulations in shorter periods of time when compared to actual rigorous multiphase flow dynamic models.

Regarding the model's representativeness, FOWM can reproduce limit cycles (severe slug flow) from OLGA with satisfactory performance. Tuned to a specific limit cycle, the model could show relative adhesion to pressures and flow with extrapolated conditions. For instance, the Hopf point was adequately mapped by FOWM. Finally, in real applications for the deepwater production system from Petrobras, FOWM showed good capability to describe limit cycles in the system, even when the dynamic was complex. Owing to the similarities in the production system's arrangement, when compared to deepwater and ultra-deepwater scenarios, the FOWM can be extended to the latter since the essential difference between them is the water depth, in other words, the riser size. Thus, the model described in this work accomplishes the goal for which it was proposed.

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Capítulo 3

Oil production increase in unstable gas lift systems through nonlinear model predictive control

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Abstract

Oil production employing gas lift techniques enable the production of no natural flow wells and supply the energy lost in the reservoir caused by the field depletion, keeping the production in brown fields feasible. The multiphase flow conditions and the long pipes used to transport the fluids from the reservoir to the surface facilities, especially in deep and ultra-deepwater cases, may create unstable flow situations. Several publications in process control have discussed this problem since the 1980s, but the potential multivariable actions on the choke valve and gas lift flow have not been explored so far. In this paper the operating oil production system is treated through a nonlinear predictive control strategy. The strategy evaluation in a rigorous model (OLGA) shows the association between predictive capability and the integrated actuation in the manipulated variables results in an oil production increase and a partial or entire suppression of the instabilities in the multiphase flow. Furthermore, the rate of acting required on the valves is lower in the multivariable approach, allowing the use of slow choke valves as a final control element.

Keywords: *NMPC, FOWM, severe slug flow, deepwater, ultra-deepwater, offshore crude production.*

3.1 Introduction

The onshore oil industry was responsible for supplying 90% of the world's crude oil in the 1970s. This number has dropped to around 70% these days, driven mainly by new discoveries in the offshore environment. The evolution of technologies in seismic has made it possible to improve exploration in saline basins and deeper waters, which reinforces the perspective of increasing the participation of the offshore industry in the world's oil supply in the next years. Notwithstanding, producing hydrocarbons in offshore conditions is more complex than in the onshore environment, which makes exploration and production more dependent on technological capacity building.

In recent years, the most relevant discoveries of new offshore carbon sources were reported in deep or ultra-deepwaters. The Brazilian pre-salt is an example of a new exploratory frontier at high depths of water. Wells installed in this area may require more than 10 km of piping to transport the reservoir fluids to the surface facilities. In deep and ultra-deepwater, pipelines typically carry the multiphase mixture containing oil, gas, water, and sediments across a series of obstacles including rocks, seabed, and ocean, which impose conditions of horizontal, vertical, and inclined flow to the fluids. One of the implications of this configuration is the appearance of instabilities in the transport flow of the multiphase mixture.

Depending on the characteristics of the fluids (mass fractions of the phases, viscosity, etc.) and the flow conditions (phase velocity, flow directions, etc.), it is possible to form regions of liquid accumulation with the effect of blocking the incoming gas upstream of the liquid accumulation. This situation forces the pressure in the gas side to increase until this pressure is high enough to push the entire mass of liquid in front of it. This kind of instability is known as terrain slugging and can occur in production columns when the production column presents a horizontal part, or in the subsea flowline where it is most common due to the irregular seabed. When this phenomenon occurs in the connection between the flowline and the riser, also called low point, the instability is known as severe slugging (riser-induced slugging) due to the significant pressure amplitude resulting in the flow.

The slugging is a cyclic phenomenon that results in permanent oscillations in the pressures and flows in the entire production system. The schematic in Figure 3.1 helps to understand the regions where instabilities are generated. More details on these slugging mechanisms are discussed in literature[1,2,3,4,5].

Another common feature of an offshore oil production system is the use of artificial lift methods. Throughout the depletion of the field, the pressure in the reservoir drops and, consequently, decreasing the driving force to transport the oil to the surface facilities. There are several ways to supplement this energy loss. The most common alternative is using natural gas injection at the bottom of the production column to reduce the column weight of the production system. This method of artificial elevation is called the gas lift.

The gas used in this strategy, provided by surface facilities, is led by a subsea line to the wellhead, called a Christmas Tree or X-Tree, which is located on the seabed, precisely on the top of the production column (or tubing), as shown in Figure 3.1. The gas enters the gas lift annular, a kind of piping that covers the production column, and it is then injected into the production column by valves whose positions are defined in the well design stage. When the gas supply is low, or when the pressure in the production column is high, an instability known as casing heading might occur.

Briefly, when the annular pressure is less than the pressure in the production column, there is no gas injection. Thus, the gas accumulates in the annulus until the annular pressure becomes sufficient for the injection of the accumulated gas. When the gas is injected into the production column, its expansion and also the reduction of the specific mass of the multiphase mixture takes place. These effects lead to a decrease in the production column pressure that increases the pressure difference from the bottom of the column to the reservoir, increasing the flow produced by the well. As a result, the pressure in the production column also increases and the pressure in the annulus drops, leading to a new blockage in the gas injection at the gas lift valve. After that, the process of accumulating pressure in the annulus starts again and another oscillation mechanism is created, also referred to as severe slugging. This process occurs slightly differently in wells without a packer[6] and can be reduced or avoided using venturi gas lift valves[7,8,9,10] in the production column. More details about this mechanism can be found in the previous works[6,11,12,13,14].

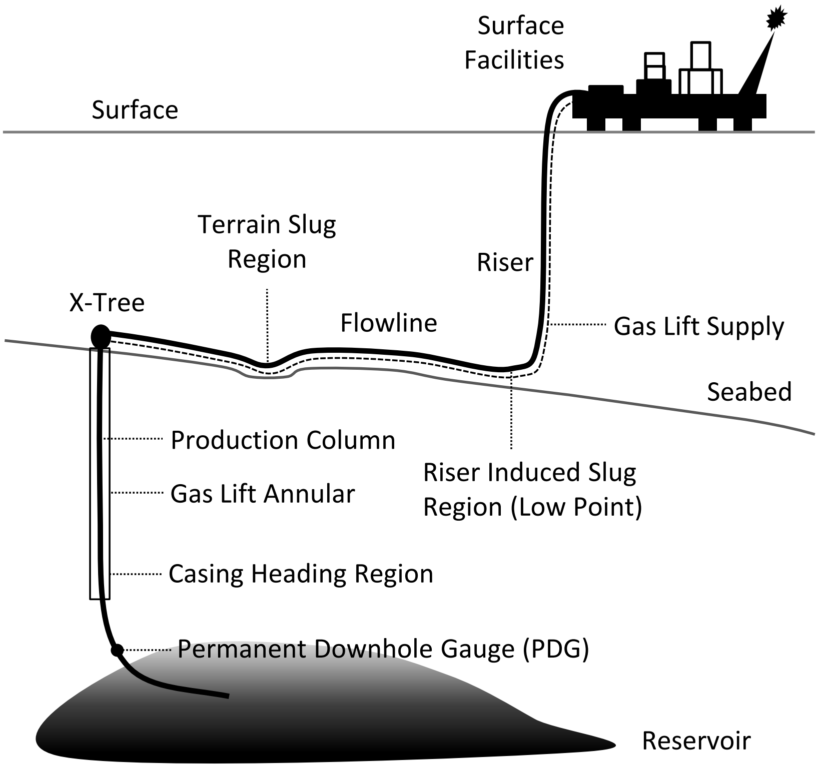

Figure 3.1 – Typical gas lifted well in a deepwater oil field and its main slugging flow causes.

There are two main consequences of an oil production system operating at a limit cycle: operational risks associated with equipment integrity resulting in the possibility of a shutdown in surface installations and the loss of production inherent to the unstable region. The general behavior of the oil production follows the trend of Figure 3.2(a) due to the opening of the topside choke valve that represents the connection of the well to the processing plant, and of Figure 3.2(b) regarding the gas lift flow. Figure 3.2(a) shows the appearing of a Hopf point during the opening of the choke valve that reflects the change in the flow stability with the consequent loss of production due to the theoretically unstable equilibrium[15]. This kind of behavior is mainly related to the riser-induced slugging. Figure 3.2(b) shows the necessity of a minimum gas lift flow for the system to achieve stability. The operation with flowrates below the Hopf point refers to the loss of production due to the theoretical equilibrium[16]. This behavior is the casing heading and can generate losses of up to 20-40% in production[12,17].

Considering the multivariable nature of the gas lift problem, as well as the complexity of its dynamics, this paper aims to present a control solution based on NMPC (Nonlinear Model Predictive Control) for the production system operation. The control structure proposed in this paper uses the surface choke valve and the gas lift flow as manipulated variables, while the controlled variable is the pressure in the Permanent Downhole Gauge (PDG). According to literature, this is the first time that this approach is explored to treat a gas lifted oil well. The results discussed throughout this paper show that the strategy can optimize and improve production stability, subject to reducing the choke and gas lift rates of change, which allows its implementation in systems with slow-speed choke valves.

This chapter is structured as follows: first a discussion about the operation mode of the gas lift oil wells is presented as well as the evolution of the possibilities of dealing with instabilities in the flow; in a second moment, the control structure proposed in this work is described; further, the model used in the predictive controller is reported; next, the main dynamic characteristics of a virtual well used as a case study in the evaluation tests of the control strategy is briefly presented; and finally the results and discussions are addressed.

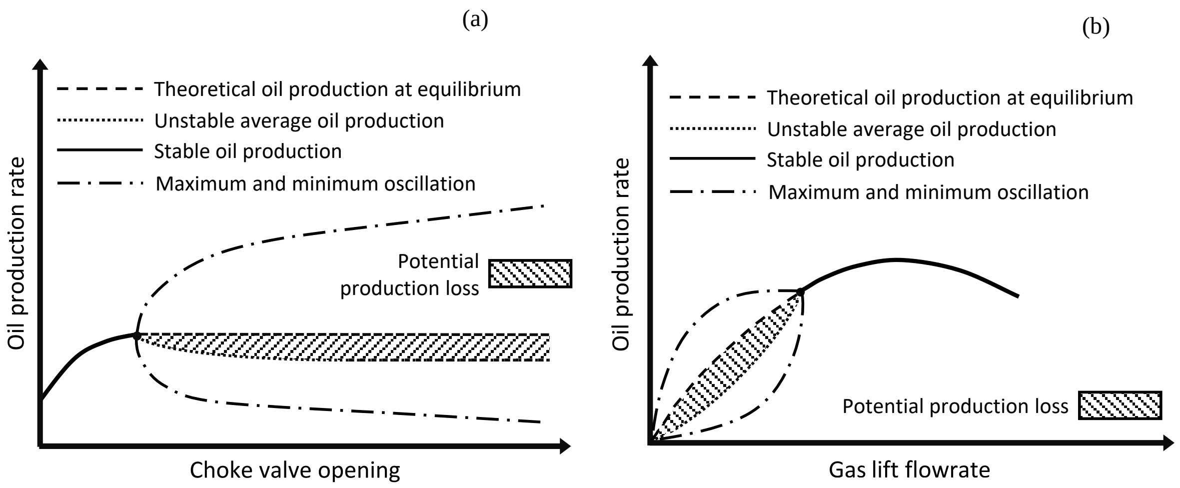

Figure 3.2 – General bifurcation diagram of oil production considering the choke valve (a) and gas lift flow (b) as bifurcation parameter.

3.2 The Oil Production System Operation

Conventionally, a gas lift oil well operation enables interventions through two variables in the surface facilities: the choke valve opening and the gas lift flow. Usually, these variables are kept constant during the operation. While attempting to work with the choke valve as open as possible, the gas lift flow is usually set to its supposed optimal flow. The gas may not be sufficient to ensure a flow that stabilizes the well or, if used in excess, can reduce oil production. Also, some wells may have a subsea production choke valve, especially if they are attached to subsea manifolds. However, due to the high maintenance costs of this type of equipment and the risks involved, few manipulations are accepted on these valves.

Another variable that may be used to act in the well is adding a demulsifier in the Christmas Tree or even in the production column by the gas lift valves. As the name suggests, its action is related to reducing the emulsions generated in the multiphase flow whose effect raises the viscosity of the fluid. Viscosity reduction facilitates the flow and reduces instabilities. However, due to its very complex physicochemical nature, which is highly dependent on the type of oil, the demulsifiers do not always have positive results. Besides, it adds costs to the operation by increasing the transport and storage logistics of chemicals, which is a frequent problem in offshore units. Thus, the most readily available variables for well actuation are the topside choke valve and the gas lift flow.

Depending on the level of the slugging, it is possible to keep the well producing without significant operational problems. However, when the oscillation intensity becomes a potential risk to the surface facilities, the actions taken by the operation are usually to increase the gas lift flow and/or reduce the choke valve's opening. As shown in the diagrams of Figure 3.2, these actions increase the flow stability but do not guarantee stability. Besides, the well can be conducted to regions of low productivity operation. This type of action usually sacrifices the well's optimization[12].

The search for stability in oil wells may have its first mark in the works of Schmidt et al. (1979)[18] and Schmidt et al. (1980)[1], which show that the pressure increase caused by choking can eliminate severe riser-induced slugging. Taitel (1986)[2] extended this analysis and presented two other stabilization alternatives: increase the pressure of the gravitational separator or insert a proportional feedback controller action on the choke valve. Blick and Boone (1986)[19], Blick et al. (1988)[20], and Blick and Nelson (1989)[21] show that it is theoretically possible to stabilize the casing heading using feedback control. The proposed control structure by these authors counts with the well pressure as a measured variable and the choke valve as a manipulated variable. However, by the end of the 1980s, none of these papers had been tested in real cases.

The 1990s began with Lemeteyer and Miret (1991)[22] reporting a way to operate wells using both gas lift and choke valves simultaneously. The strategy suggested was based on the implementation of action sequences by using fuzzy logic. Field results in shallow water wells showed the capacity to increase production and reduce using the gas.

Courbot (1996)[23] presents the automation of the strategy of reducing the choke valve opening for slugging suppression studied in the previous decade. Although the system was implemented in the field in 1994, the strategy introduces an extra pressure drop in the system since it does not deal with the instability in its essence, but rather changing the operating point to a stable region.

In 1996, Garnaud et al. (1996)[24] presented an extension of the methodology described in Lemeteyer and Miret (1991)[22], showing the ability of the action sequence to deal with instabilities. The authors affirmed they have verified in field implementations gains in oil production and a reduction of gas injected by an average of 20% for both. In this same year, Jansen et al. (1996)[16] published a theoretical-experimental study conducted in a small-scale laboratory for exploring methods of eliminating slugging in flowline-riser systems by using a production choke and gas lift flow. An indication of this research is that the association of the actuation in the production choke valve and the gas lift to slugging suppression might reduce the degree of choking in the valve, as well as the gas injected amount required to stabilize the flow.

In 1998, Kinderen and Dunham (1998)[25] presented some tools, they have called "Real-Time Artificial Lift Optimization" in order to reduce the well test time and to increase the well production. A control strategy proposed with this paper was based on stabilizing and minimizing the pressure on the gas lift annular through cascaded PID control loops. The results generated at a gas lift model in the Shell R&D lab in Rijswijk showed potential to increase oil production.

Jansen et al. (1999)[11] proposed a control approach that can be seen as an evolution of the research done by Lemeteyer and Miret (1991)[22] and Garnaud et al. (1996)[24]. The main extra ingredient of this approach is using a dynamic model for designing several linear controllers and then switching them according to the operating point for well stabilization. Unfortunately, the proposal has not been field tested.

The first feedback control applied to real wells was reported by Havre et al. (2000)[26]. The strategy was applied to a production unit on the North Sea and the manipulated variable was exclusively the production choke valve. Results showed a reduction of instability in a slugging production system when the controller was acting. The authors further showed the well returning to instability after the controller was shut down. More details of the control strategy were reported in Havre and Dalsmo (2002)[27]. Skofteland and Godhavn (2003)[28] and Godhavn et al. (2005)[29] proposed a cascade control strategy where the purpose was stabilizing the production flow in topside. Although the idea has been applied in the field, its applicability is limited since the control structure requires multiphase flow measurements of the well, which is not usually available in production systems. Dalsmo et al. (2002)[30] reported in not much detail the application of a feedback control in a shallow water well in the North Sea acting on the choke valve at wellhead production. The results show the improvement in the stability of the production and a reduction in the unit’s shutdown occurrence.

The production loss and the possibility of operating near unstable equilibrium is discussed in Hu and Golan (2003)[17] and Hu (2004)[12]. Hu and Golan (2003)[17] observed around 20-40% of production reduction due to gas lift instability for standard well settings. Hu (2004)[12] makes use of a PI control structure based on the pressure at the bottom of the well and the production choke valve. Theoretical results show average gains of 20% in oil well production.

Eikrem et al. (2008)[31] studied PI control structures for wells compatible with onshore and shallow water systems and production. The authors explore the possibility of changing the controlled variable according to the operational availability and propose a gain scheduling strategy according to the well’s operational point. The strategy proposed[31] indicates that the complexity of production system dynamics is high and, consequently, linear controllers are not appropriate to deal with operational point changes. Also, the strategies implemented in the early 2000s were heavily reliant on underwater or downhole sensors, which are measures that are not always available due to their costs and maintenance difficulties. The dynamic complexity and the scarcity of measurements motivated the model-based control solutions development. The work of Jansen et al. (1999)[11], previously mentioned, may have pioneered this approach. Storkaas (2005)[32] addresses the problem based on H-infinity and LQG controllers and explores the use of different control structures, concluding that the use of topside sensors is a limitation to the performance of simpler controllers. The use of state observers to reconstruct downhole measurements through topside sensors is addressed in computational studies such as Eikrem et al. (2004)[33], Aamo et al. (2005)[34], Sinegre (2006)[13], and Scibilia et al. (2008)[35].

The application of NMPC in oil wells is scarce in the literature. Only two recent papers have been found, however their scope is not similar when compared with this paper. In both, the NMPC is applied in a supervisory layer, being responsible for process optimization instead of our research where the controller is responsible for the regulatory (stability) and supervisory layers. The approach proposed by Codas et al. (2016)[36] where an NMPC based on Multiple Shooting is applied to two gas-lift wells is analogous to our work, however the stability is provided by two pressure controllers at the topside. The main constraint of this research is the time to compute the solution (30 minutes), which makes the method prohibitory for real applications. In the second, Krishnamoorthy et al. (2016)[37] have applied a RTO (Real Time Optimization) in a gas lift well using a simplified model. The idea was to explore how to optimize the gas lift distribution under uncertainty.

The lack of previous research with an NMPC approach is probably due to two factors: the controller algorithm and the dynamic production system model. It is expected that the dynamic model and the NMPC algorithm present good computational performance so that the control problem should be solved in a few minutes. Some severe slugging may exhibit an oscillation period of 15-20 minutes, which requires a controller sampling time of approximately 0.5-2 minutes. In the next sections, the algorithm of the controller and the model chosen will be presented. This model showed the computational performance required for the application.

3.3 The Control Strategy

The control strategy proposed in this paper makes use of the control structure illustrated in Figure 3.3. In this structure, the controlled variable is the pressure at the bottom of the well (PDG). For this, the controller uses the PDG sensor, which is the measurement closest to the bottom of the well. This variable captures the essence of well dynamics and is directly related to its production. When the average pressure in the PDG is reduced, the well begins to produce more since its productivity is directly proportional to the pressure difference with the reservoir.

In this work, the manipulated variables are the choke valve and the gas lift flow at the surface facilities. These two variables have a strong influence on the behavior of the production system, as shown previously in Figure 3.2. Related to most of the papers available in the literature, multiple input actuating is a differential because it does not consider the choke valve alone as the manipulated variable. The association of choke valve and gas lift allows a more global performance in the operation of the production system and its effects are evaluated in this research.

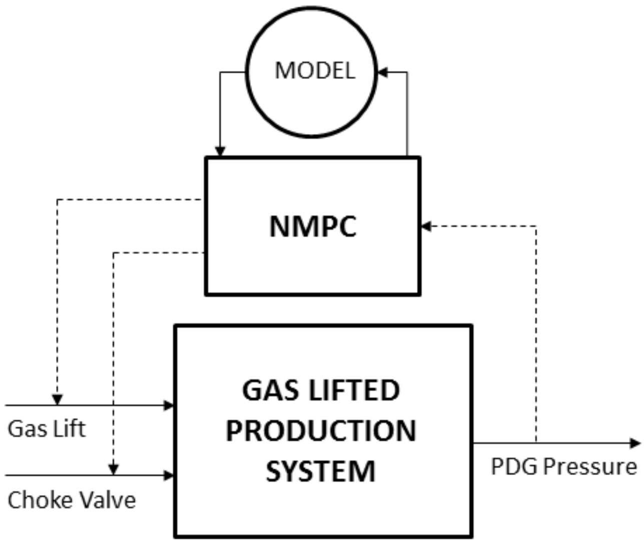

Figure 3.3 – Control structure proposed in this paper.

The NMPC employed in this work is based on the LLT algorithm[38] and uses dynamic linearization along a trajectory of control actions that are updated at each iteration until they converge. In the case of dynamic linearization, the matrices corresponding to the linearized model are recalculated for each point of the predicted trajectory with values from the variables of the time instant referred.

The control actions are determined by solving the following quadratic programming (QP) problem:

$$J = \min_{s,\delta U_{\left[\begin{smallmatrix}M\\0\end{smallmatrix}\right]}} \left(\begin{array}{l} \sum_{i=0}^{P} \left(\gamma_i \cdot (y_i - r_i)\right)^2 + \sum_{i=0}^{M} \left(\lambda_i \cdot \left((\delta u_i + u_{i-1}^B) - (\delta u_{i-1} + u_{i-2}^B)\right)\right)^2 + \\ \sum_{i=0}^{M} \left(\psi_i \cdot \left((\delta u_i + u_{i-1}^B) - z_i\right)\right)^2 + \left(\varphi |s|\right)^2 \end{array} \right) \tag{3.1}$$

Under the following constraints:

$$\begin{array}{l} U_{\min\left[\begin{smallmatrix}P\\0\end{smallmatrix}\right]} \leq U^B_{\left[\begin{smallmatrix}P-1\\-1\end{smallmatrix}\right]} + \delta U_{\left[\begin{smallmatrix}P\\0\end{smallmatrix}\right]} \leq U_{\max\left[\begin{smallmatrix}P\\0\end{smallmatrix}\right]} \\ -\Delta U_{\min\left[\begin{smallmatrix}P\\0\end{smallmatrix}\right]} \leq \Delta U_{\left[\begin{smallmatrix}P\\0\end{smallmatrix}\right]} \leq \Delta U_{\max\left[\begin{smallmatrix}P\\0\end{smallmatrix}\right]} \\ Ys_{\min\left[\begin{smallmatrix}P\\0\end{smallmatrix}\right]} - s \leq Y_{\left[\begin{smallmatrix}P\\0\end{smallmatrix}\right]} \leq Ys_{\max\left[\begin{smallmatrix}P\\1\end{smallmatrix}\right]} + s \\ \mathrm{s} \geq 0 \end{array} \tag{3.2}$$

The objective function shown in Equation 3.1 presents four terms. The first term considers the weighting of the error between the reference trajectory r_i and the prediction of the model y_i for the time instants i between the current time instant 0 and the last prediction instant P. The second term is called move suppression and serves to weight the variation of the control actions u_i for the time instants i between the current time and the last instant of the control horizon M. The superscript B placed in the variables indicates that these are linearization bias-values corresponding to the values of preceding instances of each variable. The linearization bias-value B is defined by the simulated values of the nonlinear model with the control action of the last iteration. This bias value is necessary, since the optimization problem Equation 3.1 and 3.2, for the next iteration, is built using the linearized models obtained along the trajectory.

The third term, usually called target, considers the error between the value of the manipulated variables u_i and their target values z_i for the time instants i between the current time instant 0 and the last instant of the control horizon M. Finally, the fourth term weighs the tolerance of the ponderable constraints s. The weights of each objective function term are given by γ, λ, ψ and φ.

Concerning to the constraints, U and Y represent matrices of manipulated and controlled variables, respectively.

The calculation procedure of the LLT algorithm starts with the linear model prediction and the Quadratic Problem (QP) is solved at each iteraction. This gives the first trajectory designed for the system. With this first reference trajectory, the first set of linearized models is determined, which will replace the initial model. With this set of models, a new set of control actions is generated, which is then applied to the non-linear model, creating a new trajectory and a new set of linearized models. The control actions are determined in this sequence of iterations until a convergence is reached.

The difference is small between the LLT algorithm and typical Sequential Quadratic Programing (SQP) NMPC algorithms[39]. First, in the LLT algorithm, the trajectory update is based on the control actions computed in the previous sampling time and applied in the plant instead of the previous value of the actual trajectory in actual convergence procedure. Second, the LLT algorithm is responsible for the trajectory convergence, solving several QP problems until the trajectory convergence, instead of using an SQP solver.

The feedback of the NMPC is done by the estimation of initial conditions through a Hybrid Extended Kalman Filter (H-EKF), as described in Appendix A.

The controller was configurated with a sampling time of 90 seconds, equal weights in the suppression movement – 5 and 5 – and a variation in the set point weight described in the results – 5 to 50. Targets and soft constrains are not used. Control and prediction horizon were set at 2,500 and 6,000 seconds respectively. The NMPC input/output scaling were set at the same magnitude of the physical variables (valve opening, flowrate, and pressure). The state estimator is called every 180 seconds to feed back the initial conditions to the NMPC model integration. This strategy mainly corrects the phase difference between the well response and the prediction. The EKF scaling counts with 10% of the model's state average to Q matrix and 2×10^7 to the R value.

3.4 Modelling Approach

The literature presents several models based on ordinary differential equations (ODE)[31,40,41,42,43,44,45,46,47] and partial differential equations (PDE)[48,49,50,51,52] to describe the dynamic behavior of oil wells. Although we used an ODE approach in the NMPC, the PDE models are an option under study.

Most of the ODE models are not suitable for deepwater wells because they partially model the architecture of the production system. This means that these models are in fact suitable for onshore or shallow water production systems or even modelling only the subsea pipelines. Two of these models stand out because they are more comprehensive in describing the architecture of deepwater oil production systems[43,47]. The Jahanshahi (2013)[43] model includes the description of the riser, flowline, and production column. However, it excludes the gas lift annular in the modeling, which prevents it from describing instabilities caused by casing heading. In addition, this model presents numerical stiffness, which makes its use prohibitive in a predictive controller.

The model from Diehl et al. (2017)[47], called FOWM (Fast Offshore Wells Model), exhibits a more complete description, including the riser, flowline, well, annular gas lift, and a nonlinear reservoir based on the Vogel model (1968)[53]. Based on this model, we do not experience numerical stiffness in FOWM within the normal operating regions of a deepwater well, which makes it suitable to be used in an NMPC with a sampling time of no less than one minute. This model was also implemented in real cases showing superior results in the representation of complex dynamics such as limit cycles and stability change. Thus, the model chosen for the NMPC used in this work was FOWM.

FOWM is a model based on mass conservation and its equations describe the behavior of gas and liquid phases through the segmentation of the production system into two large blocks: the set below the seabed formed by the production column and the gas lift annular, and the submarine set formed by flowline and riser. The FOWM consolidates in a single model the ideas of Eikrem et al. (2008)[31], Di Meglio et al. (2011)[40], Jahanshahi et al. (2012)[41], and Vogel (1968)[53]. The integration and modification of these models results in a six-state model that is described in Diehl et al. (2017)[47]. The mathematical artifice that allows to create the effect of blockage on the flowline is a virtual valve[39] that partially blocks the passage of gas under certain conditions.

Details of the FOWM adjustment methodology along with the model results representing dynamic behaviors of real production systems can be found in the original work[47].

3.5 The Production System's Dynamics

The production system used to test the control strategy consists of a virtual plant connecting the transient multiphase flow simulator Olga® and the dynamic processes simulator Unisim Design®. The focus of the research is the analysis of a single well whose architecture is similar to the one shown in Figure 3.1. In Olga®, the whole subsea pipeline, production column, annular, and reservoir were modeled, while the topside facilities interfaces with the riser and the subsea gas lift line were modeled in Unisim Design®.

The virtual production system is the representation of a Basin Campos real well from Petrobras. Its characteristics and dimensions, corresponding to well A, were previously presented in detail in Diehl et al. (2017)[47]. Briefly, well A described in Figure 3.4 is composed by a production column of 1,569 m, a gas lift annular of 1,118 m and a subsea pipe of 4,497 m. The system's production diameter is 0.15 m and the liquid produced has a density of 900 kg/m³. Around the flowline's middle there is a low point in the seabed that is the main cause of instabilities, as pointed out in the terrain slugging formation zone in Figure 3.4.

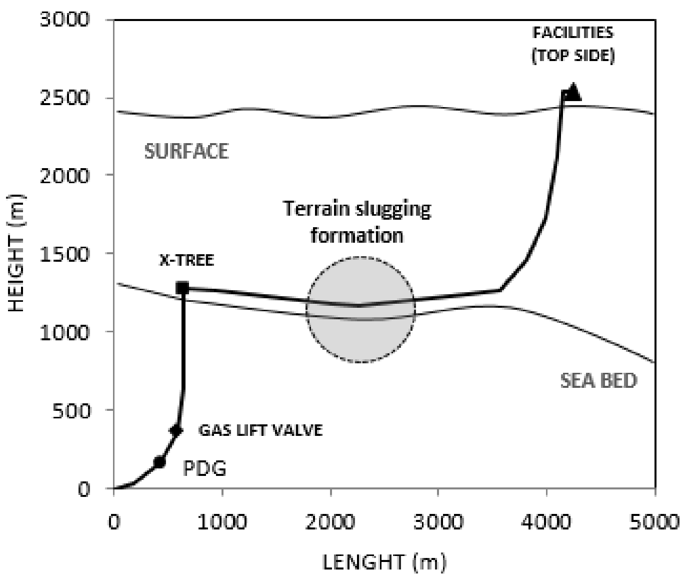

Figure 3.4 – Deepwater well in Basin Campos: a case study, well A.

In order to increase the fidelity of the real system representation, a PI controller of surface gas lift flow was included with a similar dynamic to the actual controller. This well's production choke valve is manipulated through a step actuator. This actuator presents slow dynamics and its full opening or closing usually takes 5-10 min. This type of situation tends to be a limiting characteristic for the performance of the controllers. An opening/closing rate of 0.24 $\%.s^{-1}$ has been included in the virtual system as a speed restriction on the choke valve, which is equivalent to a total opening or closing time of 7 min.

Relying on the choke valve opening conditions and the gas lift flow, the dynamic behavior of the production system may present regions of stability and instability. Figure 3.5 shows the pressure behavior pattern at the PDG measurement point for various choke openings and gas lift flows.

In general, the stability of the PDG represents the multiphase flow stability condition in the entire production system. This means that when the pressure in the PDG is oscillating, the pressure across the production line will also be.

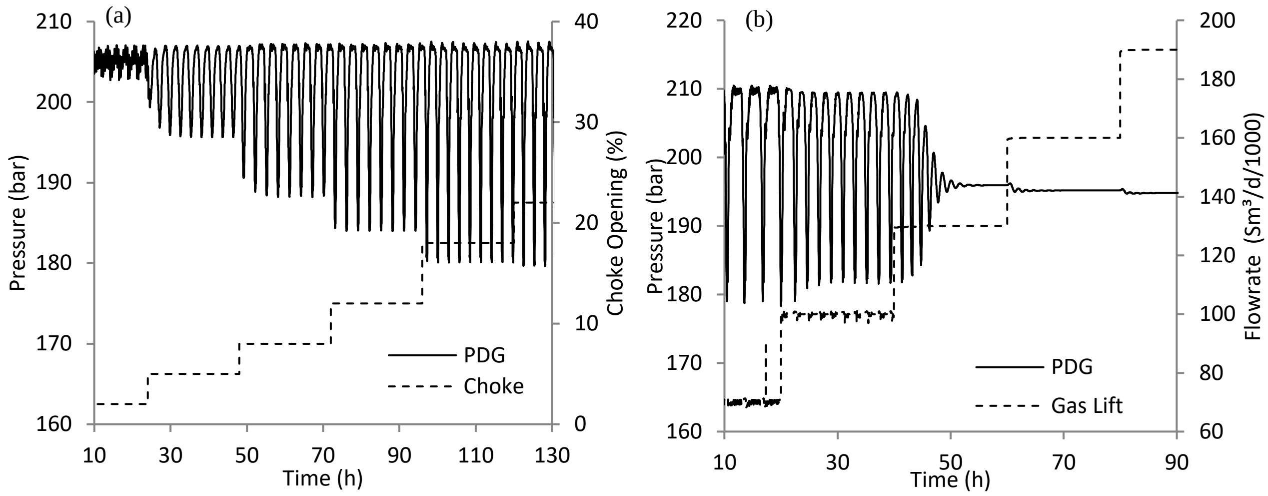

Figure 3.5 – Well A dynamic behavior in the Olga/Unisim simulator: choke valve opening (a) and gas lift flow (b).

A global way of representing the dynamics of a nonlinear system is through bifurcation diagrams. Figure 3.6 shows the pressure bifurcation diagrams on PDG. The bifurcation parameters are the choke valve opening and the gas lift flow. As it can be seen, closing the choke valve and increasing the gas lift flow tend to reduce the well instability. Operators usually adopt these control actions in adverse situations. However, restricting the choke opening may reduce well production by increasing back pressure, while increased gas lift flow may be economically disadvantageous or unfeasible due to gas production constraints and the plant's compression limitations.

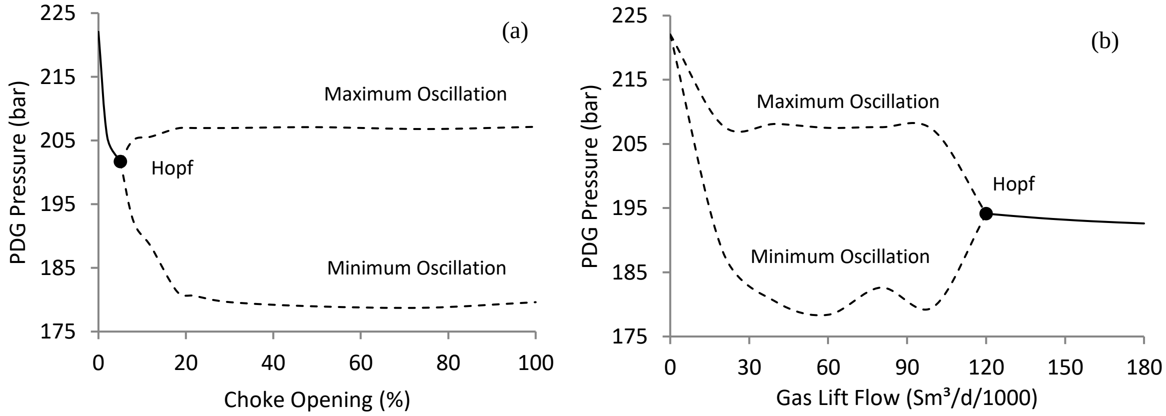

Figure 3.6 – Bifurcation diagram PDG: choke valve opening (a) and gas lift flow (b).

The Hopf point mapping for the operational conditions of the choke valve and the gas lift flow allows the stability frontier of the production system to be obtained. The curve shown in Figure 3.7 was obtained for the system in question.

This mapping makes it possible to determine the choke and gas lift flow combinations that in an open-loop result in a stable or unstable dynamic behavior. Changes in the reservoir conditions, such as pressure and/or water fraction, may alter this curve. Variations in the liquid viscosity, generally arising in the formation of emulsions during the flow, also cause changes in this stability pattern. Fortunately, in a normal situation, this type of behavior transition in the production system is slow and usually takes months to be seen.

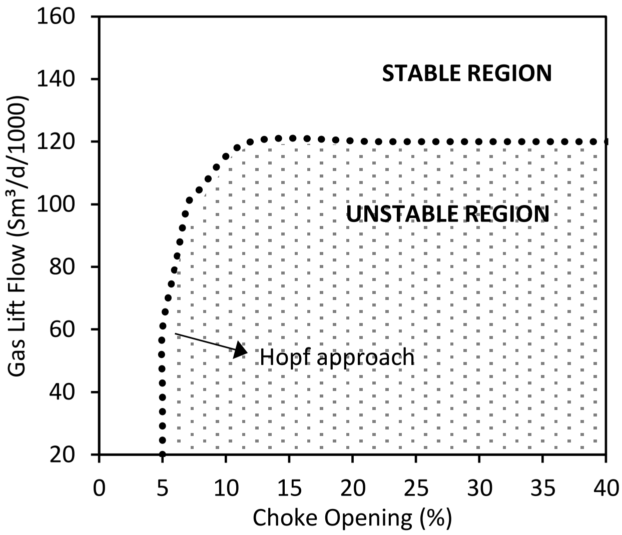

Figure 3.7 – Stability frontier of Well A mapped through Olga/Unisim model.

The oil production is affected by the flow instabilities, significantly reducing the well's production potential. Figure 3.8 shows the oil production surface in relation to the gas lift and the choke valve. Basically, it is possible to recognize two main production levels: one high and another low. The reason for the difference between the high and low production regions is the stability of the flow. The production of oil suffers a considerable reduction when the flow is unstable.

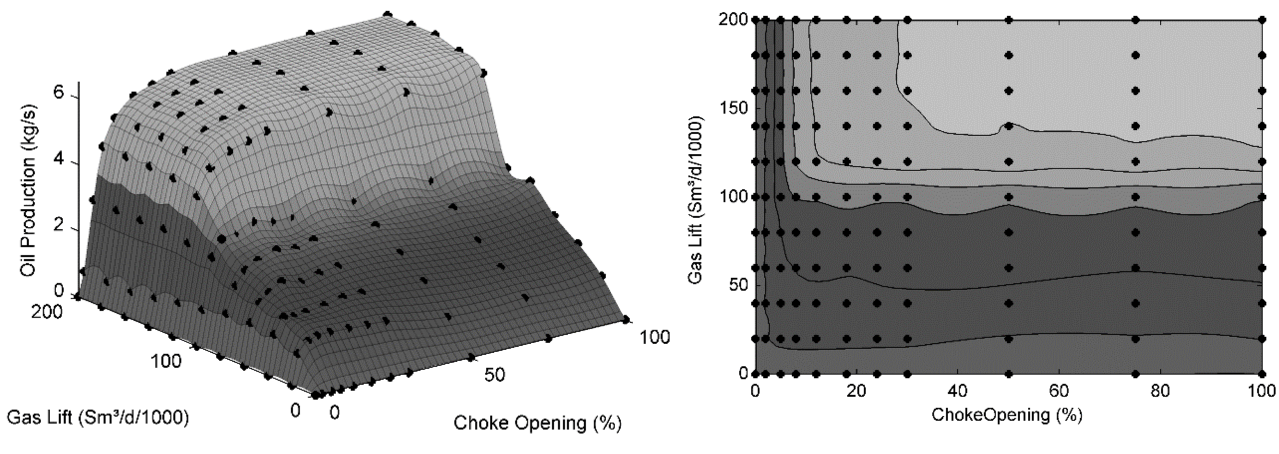

Figure 3.8 – Oil production surface in Well A. The lowest production operating area is equivalent to the well's unstable region.

The behaviors shown so far were generated based on the production system model in the Olga/Unisim simulators. The adaption of the simplified model FOWM to the Olga/Unisim is presented in Figure 3.9 and 3.10. The oscillation amplitude and the stability changing were relatively well captured by FOWM (Figure 3.9), while frequency and phase were less well represented in large prediction windows (Figure 3.10).

However, feedback of the states through the EKF allows the signal phase correction. An example of that is seen in Figure 3.11 where PV is the process variable (PDG pressure) and PRED is the FOWM prediction. After 18 hours, the EKF was turned on eliminating the lag between PV and PRED through the FOWM initial condition estimation.

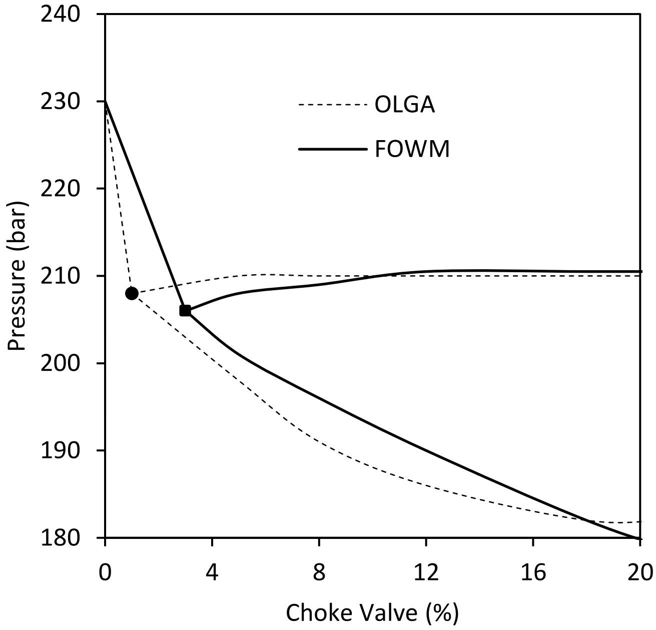

Figure 3.9 – Bifurcation diagram: Olga/Unisim model versus FOWM.

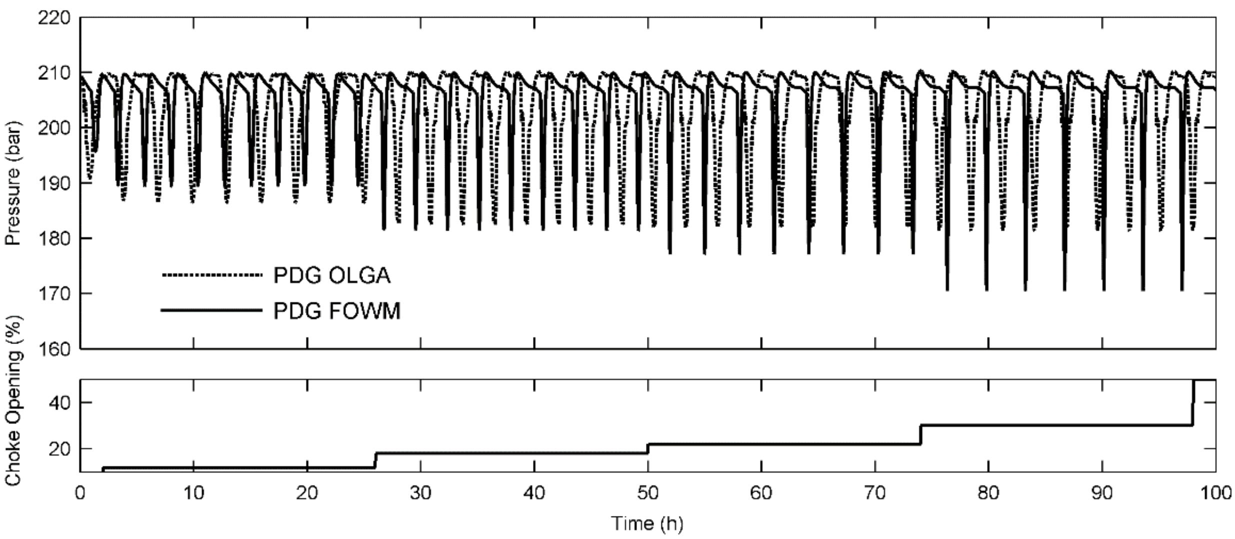

Figure 3.10 – Dynamic response: Olga/Unisim model versus FOWM.

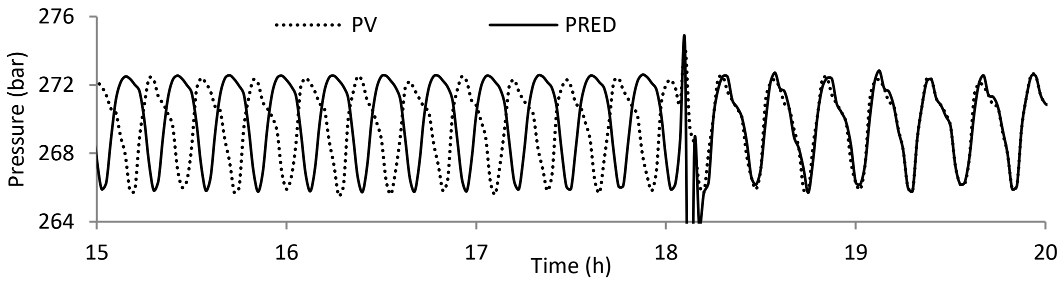

Figure 3.11 – Phase correction by EKF.

3.6 Results and Discussion

The control strategy proposed in this research is firstly evaluated through comparing the open-loop (OL) results versus the closed-loop (CL) time response. Figure 3.12 shows well A before and after the actuation of the controller triggered between 10-12 h of simulation. Prior to the controller actuation, the well's oscillation amplitude was around 30 bar in the PDG. The Temperature and Pressure Transmitter (TPT) are located in the X-Tree and exhibit amplitude oscillations around 60 bar in open-loop. Around 12 hours after, the controller is turned on and the production system practically shows a stable behavior. The PDG stabilization affects the entire flow stabilization, as can be seen in the TPT behavior and in the topside pressure (TOP). In open-loop, the well produced an average of 2.79 kg/s of oil between 4 and 10 h. After the well's stabilization, the production increased to 3.80 kg/s, which represents an increase of 36% in oil production. The choke valve that was at an 18% opening was restricted to 7.2%, while the gas lift flow was increased from 80,000 Sm³/d to around 88,000 Sm³/d.

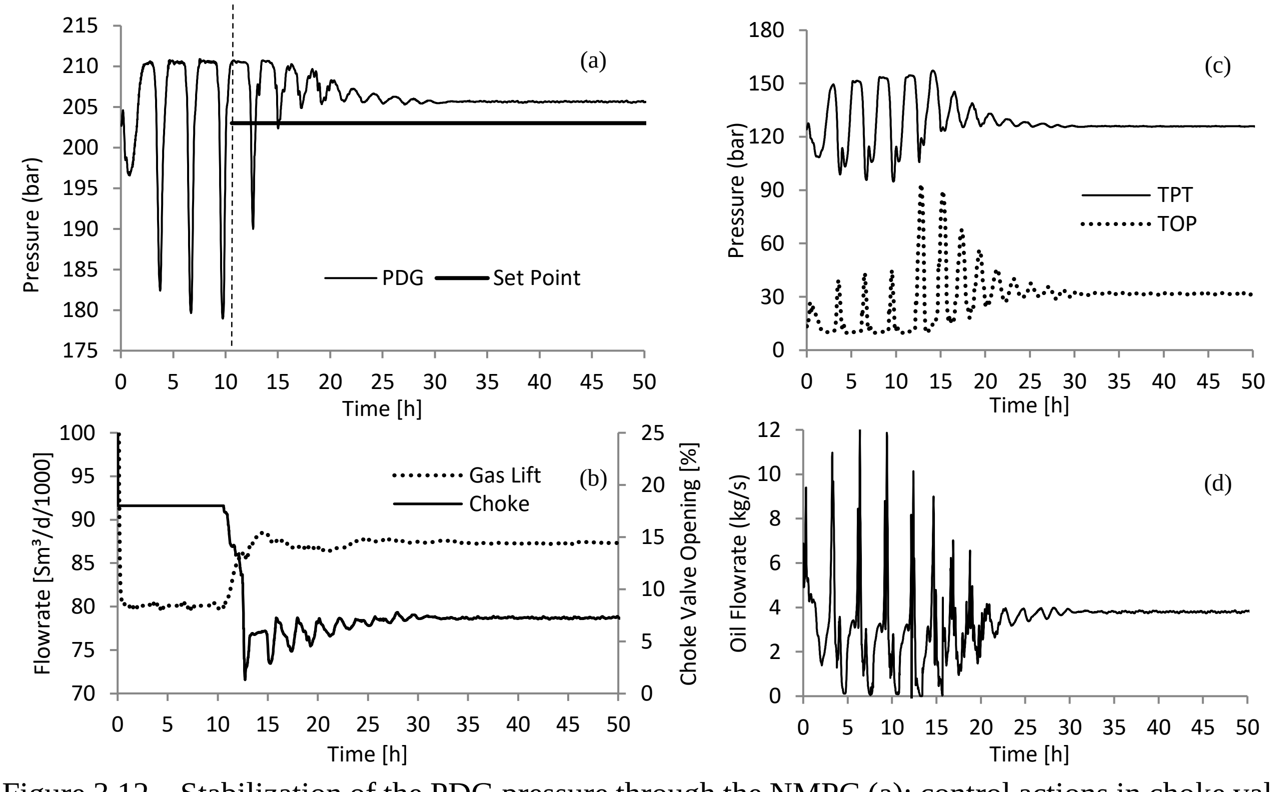

Figure 3.12 – Stabilization of the PDG pressure through the NMPC (a); control actions in choke valve and gas lift flow (b); response of other pressures in well A (c); and oil production in the topside facilities (d).

Despite the well stabilization, the controller did not lead the pressure from the PDG to its set point (SP). The set point was 203 bar, while the value obtained by the controller was 206 bar. One way to reduce this offset is by increasing the set point weight in the predictive controller's cost function. The results of changing this configuration, as shown in Figure 3.13, exhibit the controller actions leading the PDG pressure to orbit the set point, but it cannot maintain a stability as the one verified in the case of a low set point weight. Therefore, the pressures in the PDG and TPT show average amplitudes of 3 and 4 bar, respectively. The gas lift flow is increased to its upper bound (100,000 Sm³/d), which simulates a gas availability limit condition. The choke valve oscillates with a larger average opening from 7.2% to 10.7%. Despite this, the slugging intensity is well controlled, and the average oil produced increased from 3.80 kg/s to 4.50 kg/s, an equivalent gain of approximately 18% on the average oil production.

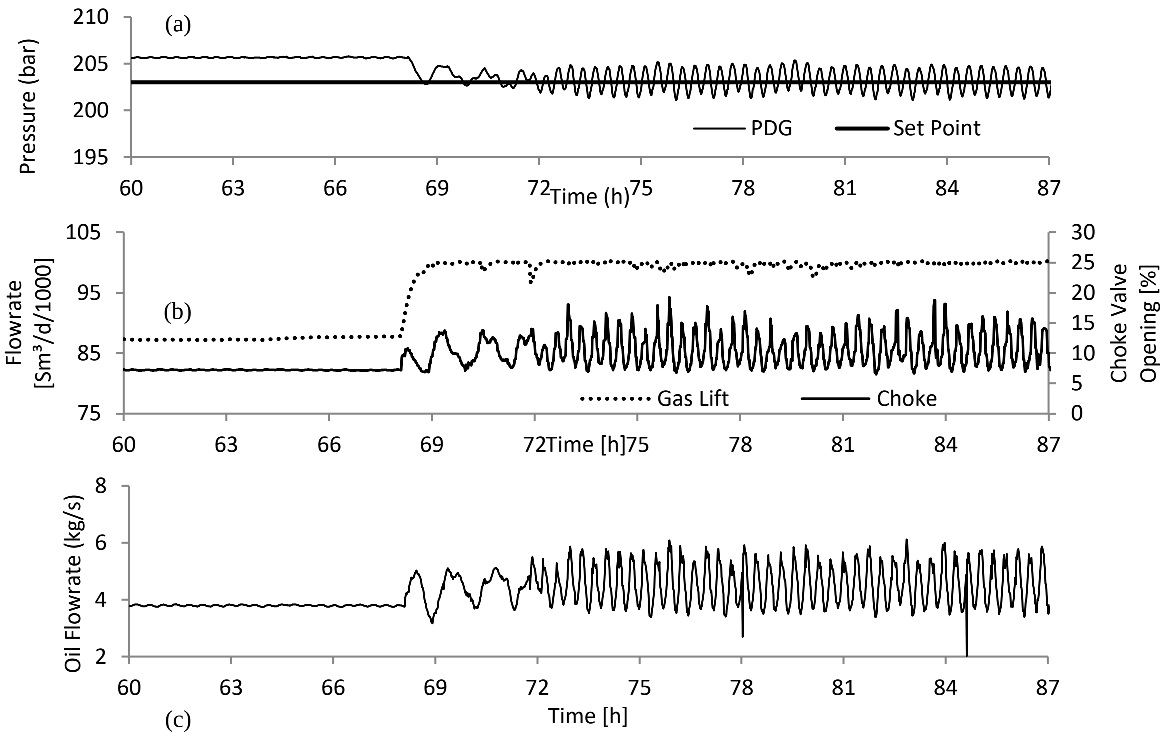

Figure 3.13 – Pressure in PDG after a SP weight increase in NMPC objective function (a); control actions in choke valve and gas lift flow (b); oil production in the topside facilities (c).

To help understand the results obtained, Figure 3.14 shows the well A production system stability map in relation to the choke valve and the gas lift flow. This map exhibits the system stabilization shown in Figure 3.12 and was obtained by the operational point change. In an automatic manner, the controller took the well from an unstable region to a region closer to stability. The change in SP weight shown in Figure 13 forces the controller to enter the instability region, which consists of a more challenging operating point, and hence the controller actuates more intensely.

So far, part of the positive results verified are due to two characteristics: the capacity to change the operational point and the stabilization of the limit cycle. The change of the operational point can be seen as an optimization and stabilization as a purely controlling characteristic. As shown in Figure3.12, the operating point change has clear benefits and is a strategy used in manual mode by operation without conduction through an optimized transient as the controller does. The test shown in Figure

3.15 was performed in order to evaluate the advantages of the control strategy without an operational point change, which means analyzing the stabilization capacity exclusively. In this test, the dynamic well behavior was compared at the same average operating point with the open-loop and closed-loop cases. Thus, for the same operating point, the amplitude of the oscillation in the PDG was reduced from 20 bar in open-loop to about 4 bar in closed-loop. In terms of oil production, the average in open-loop was 2.9 kg/s, while in closed-loop the oil flow rate reached was 4.2 kg/s. In relative terms, an increase of around 45%. Figure 16 presents the controller trajectory. The orbit assumed by the NMPC shows that the controller was, on average, operating at the same point as the open-loop for this test.

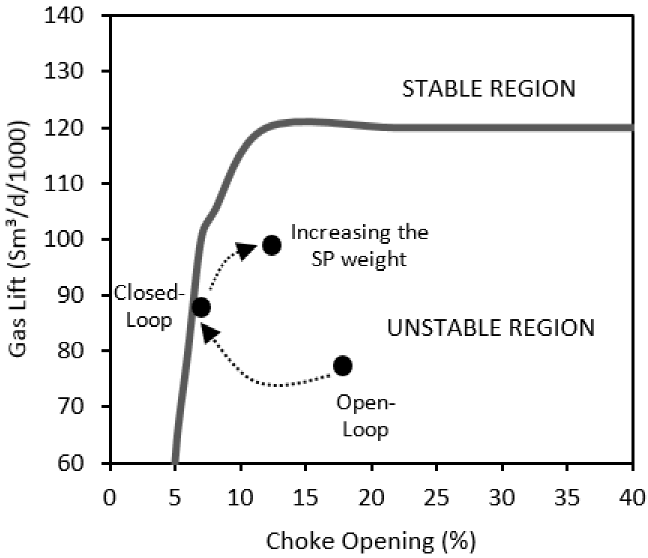

Figure 3. 14 – Operation points in the stability map.

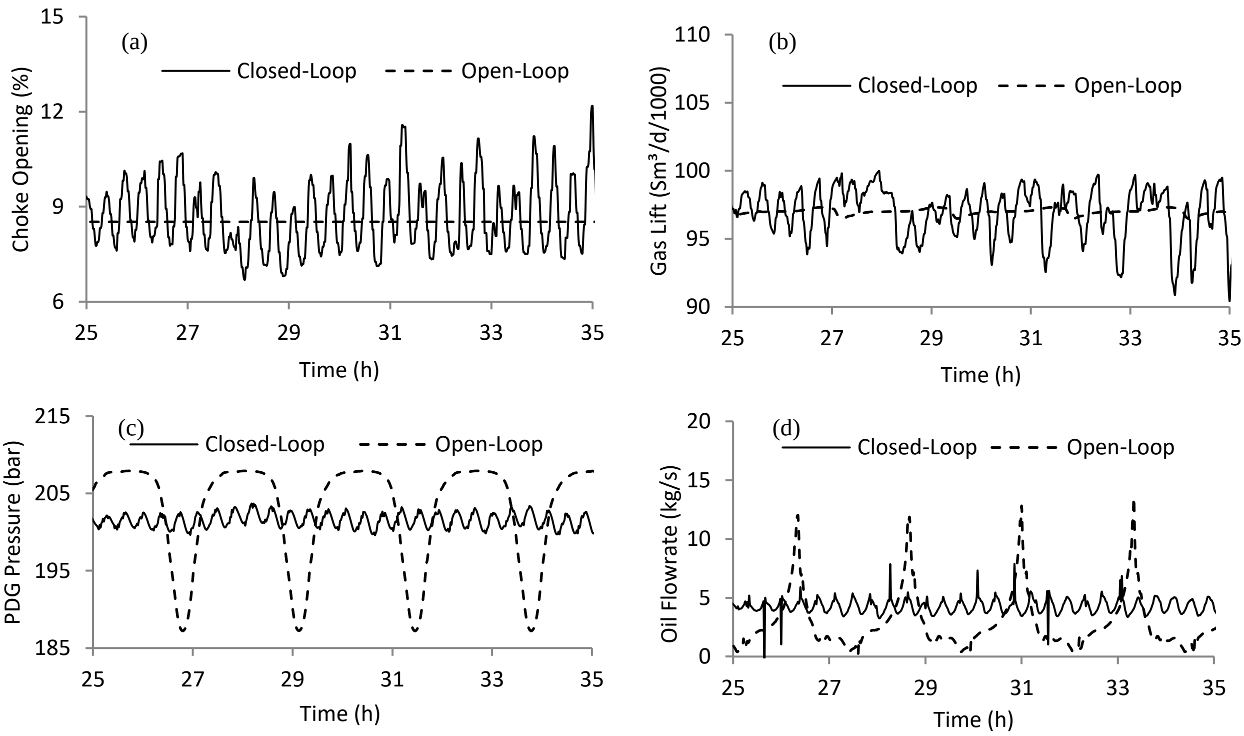

Figure 3.15 – Comparing the same operational point (choke valve opening and gas lift flowrate): open-loop versus closed-loop. The graphics shows the choke valve (a), gas lift flow (b), pressure on PDG (c), and oil production on topside (d).

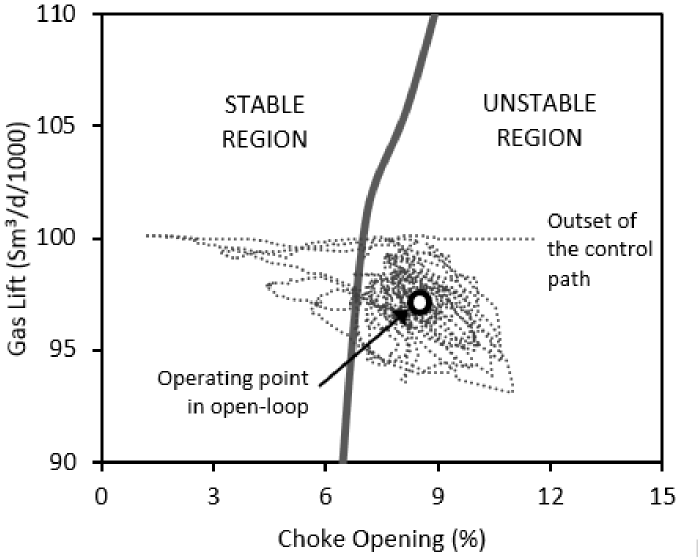

Figure 3.16 – Manipulated variables trajectory reinforcing that closed-loop was orbiting the open-loop operational point.

A second control structure was evaluated in terms of the capability to reduce slugging. This second control structure consists of acting exclusively on the choke valve as it considers that the gas lift flow is not available for handling. Figure 3.17 is presented to evaluate the performance of the NMPC in this situation. Two closed-loop conditions are compared to the open-loop response: the former considers the same choke valve (Slow Choke) used in all previous tests with opening-closing time from 0-100% in 7 min, while the latter considers a choke valve with a total opening-closing time of 15 s (Fast Choke).

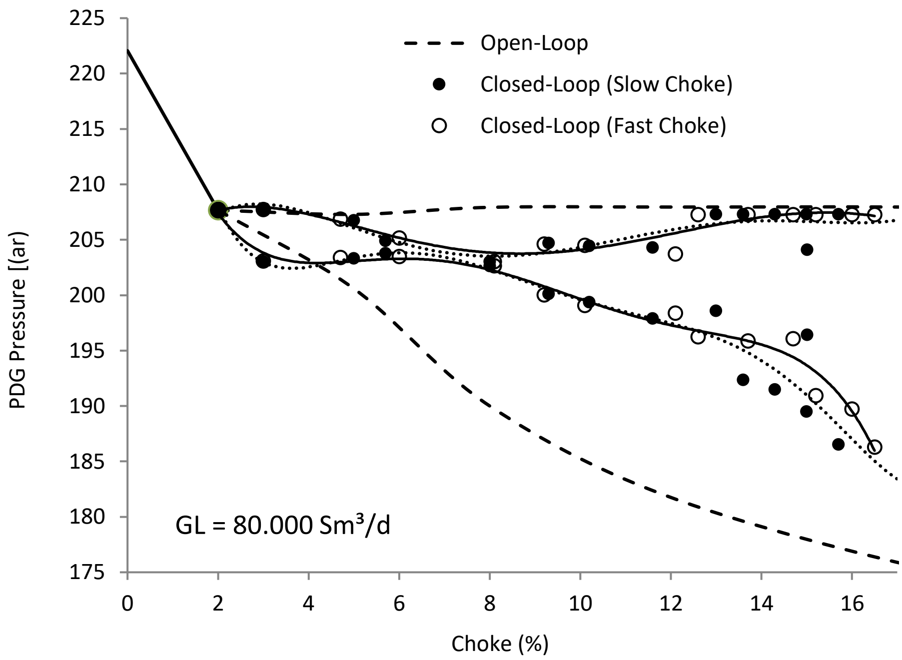

Figure 3.17 – Orbit diagram showing the performance of different choke valves in the slugging suppression.

The simulated results show that the control strategy can reduce the oscillation amplitude regardless of the type of choke valve available and gas lift unavailability. This fact is due to the predictability characteristics of the controller, allowing it to anticipate the dynamics of the system. Near the Hopf point, the controller presents a poorer performance, probably due to the discrepancy between the bifurcation point of the virtual plant and the FOWM model (Figure 3.9). The controller tends to lose performance with large choke openings. From 18-20% valve opening onwards, the process gain is zero, as shown previously in Figure 3.4. This means that opening or closing the valve above this region does not cause change in the well dynamics and therefore the controller tends to lose performance.

Comparing the MISO structure of Figure 3.15 with a similar operating point of the SISO structure of Figure 17 (Slow Choke), it is verified that the average choke valve variation rate by sampling time (ST) is 0.3%/ST and 0.4%/ST for the MISO and SISO cases, respectively. Although the mean difference is small, the maximum manipulation rate verified in the MISO case is 2.7%/ST, whereas in the SISO case it is 10%/ST.

This means that the multivariable actuation distributes the handling between the choke valve and the gas lift flow. This may reduce the need to act more intensively on the manipulated variables as can be seen in the comparison between the maximum rates of the MISO and SISO. In a production plant, it is desirable to minimize the actuation on valves in order to reduce the fault risks indexes of the equipment. Thus, the multivariable control presented better performance according to the operational reliability prerequisites, corroborating the advantage of the MISO structure.

Table 3.1 summarizes the results described previously.

Table 3.1 – Summary of the results.

CASE	RESULTS
Open-loop versus closed- loop (Figure 3.12)	1) Oscillation magnitude in PDG reduced from 30 bar to zero bar 2) Choke valve opening reduced from 18% to 7.2% 3) Gas lift flow increased from 80,000 Sm³/d to 88,000 Sm³/d 4) Oil flow increased from 2.79 kg/s to 3.80 kg/s
SP weight increasing (Figure 3.13)	1) PDG average pressure dropped 2) DP in PDG increased from 0 bar to 3-4 bar 3) Choke valve opening increased from 7.2% to 10.7% 4) Gas lift reached the upper flowrate threshold 5) Oil increased from 3.8 kg/s to 4.5 kg/s
Same operating point (Figure 3.15)	1) Choke valve opening average and the gas lift flow average is the same in open-loop and closed-loop 2) Oscillation magnitude in PDG reduced from 20 bar to 4 bar 3) Oil increased from 2.9 kg/s to 4.2 kg/s
Acting only on choke valve (Figure 3.17)	1) Even in a SISO structure, the controller keeps the capability to suppress instabilities 2) Predictability feature enables using slow choke valve as final control element

The controller robustness was evaluated through several tests with structural mismatch, i.e., the plant is the Olga/Unisim simulators and the model inside the controller is FOWM simplified model. However, numerical properties of the NMPC algorithm were not addressed at this work.

3.7 Conclusion

The nonlinear predictive control strategy model using FOWM to predict the dynamic behavior of the pressure near the bottom of the production column has shown to be able to improve how an unstable oil production system is operated. The main results obtained shows the partial or total suppression of severe slugging and an increase in oil production. The most important points to highlight are listed below:

- By manipulating the choke valve and the gas lift flow, the NMPC can change the operating point of the well and find an operating region with more stability considering the constraints imposed on the controller, such as small gas availability in the gas lift system.

- NMPC is also capable to reduce or even eliminate oscillations in the naturally unstable open-loop region. Furthermore, the control strategy can keep the well more stable at an average operating point equivalent to the open-loop operation point. Thus, the controller takes on a role of slugging attenuator, reducing the instability intensity.

- Increases in oil production were observed when the production system was operated by the controller. Part of this gain is due to the change in the operating point and another part due to stabilizing the intermittent flow. The combination of these features is a powerful device for optimizing an oil production system. The gains verified in this work reached around 45%, which corroborates with the order of magnitude expected in some research papers such as Golan and Hu (2003)[17] and Hu (2004)[12]. However, the gains are strongly linked to the reservoir flow constant K_r, which in a linear representation of the reservoir, often called the well's productivity index, and the unstable equilibrium point, which is the minimum pressure theoretically achievable for a specific choke opening and gas lift flowrate. Therefore, the increase of oil productivity relies on the characteristic of each production system by itself.

- In relation to manipulated variables, the proposed control strategy has two benefits: firstly, it allows slow acting choke valves and fast acting choke valves to perform similarly. This extends the technology implementation range since it is very common to use inherently slow step actuators in choke valves. Secondly, the multivariable control strategy allows the intensity of action between the production choke and the gas lift flowrate to be divided, which results in smoother movements in the variables manipulated.

The ability to change the operating point, reduce instability, and minimize the control actions in the variables manipulated are the best advantages of the approach proposed to deal with an unstable gas lifted well.

Appendix A: Hybrid Extended Kalman Filter (H-EKF)

Consider the following nonlinear dynamic system to be used in the state estimator

$$\begin{aligned}
&\dot{x} = f\left(x,u,t,p\right)+\omega\left(t\right) \\
&x(0) = x_0 \\
&y_k = h_k\left(x_k,t_k\right)+\nu_k \\
&\omega\left(t\right) \sim \left(0,Q\right) \\
&\nu_k \sim \left(0,R_k\right)
\end{aligned} \tag{A1}$$

where u denotes the deterministic inputs, x denotes the states, y denotes the measurements, and p denotes the parameters. The process-noise vector $\omega(t)$ and the measurement-noise vector ν_k are assumed to be a white Gaussian random process with zero mean and a covariance Q and R_k, respectively. The H-EKF formulation uses a continuous and nonlinear model for state estimation, linearized models of the nonlinear system for state covariance estimation, and discrete measurements[54]. This is often also referred to as continuous-discrete extended Kalman filter[55]. The system is linearized at each time step to obtain the local time-varying system matrices

$$\begin{aligned}
&F_x\left(t\right) = \left(\frac{\partial f}{\partial x}\right)_{x,u,t,p_{nom}} \\
&H\left(t\right) = \left(\frac{\partial h}{\partial x}\right)_{x,u,t,p_{nom}}
\end{aligned} \tag{A2}$$

where the subscript nom describes nominal values. The equations that compose the different steps in the H-EKF are given below:

State Transition Equation:

$$\hat{x}_{k|k-1} = \hat{x}_{k-1|k-1} + \int_{k-1}^{k} f\left(\hat{x},u,\tau,p\right)d\tau \tag{A3}$$

State Covariance Transition Equation:

$$P_{k|k-1} = P_{k-1|k-1} + \int_{k-1}^{k}\left[F_x\left(\tau\right)P\left(\tau\right)+P\left(\tau\right)F_x\left(\tau\right)^T+Q\right]\ d\tau \tag{A4}$$

Kalman Gain Equation:

$$K_k = P_{k|k-1}H_k^T\left[H_kP_{k|k-1}H_k^T+R_k\right]^{-1} \tag{A5}$$

State Update Equation:

$$\hat{x}_{k|k} = \hat{x}_{k|k-1} + K_k\left[y_k - h\left(\hat{x}_{k|k-1},\ t_k\right)\right] \tag{A6}$$

State Covariance Update Equation:

$$P_{k|k} = [I_n - K_k H_k] P_{k|k-1} [I_n - K_k H_k]^T + K_k R_k K_k^T \qquad (A7)$$

Usually the error covariance matrices Q and R_k are considered as tuning parameters to adjust the filter's performance.

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Capítulo 4

10% Increase in Oil Production Through a Field Applied APC in a Petrobras Ultra-Deepwater Well

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Abstract

As an offshore oil well ages, it is common for the production system to face multiphase flow problems such as limit cycles. This phenomenon, known as slugging in the jargon of the oil industry, causes oscillations in the well's flowrate and pressure. Its main effects are reducing production and increasing the risk of operational discontinuity due to shut down. In this chapter, an advanced control process (APC) strategy is presented to deal with the slugging problem in oil wells. The strategy uses a two-layer coupled control structure: a regulatory via a PID control, and a supervisory via a model-based predictive control (MPC). The structure proposed was applied to a real ultra-deepwater well in Petrobras that was partially restricted by the choke valve to avoid the propagation of oscillatory behavior to the production system. As a result, the well has achieved a 10% oil production increase while maintaining the flow free of severe slugging, which meant an increment of about 240 barrels a day for that specific well.

Keywords: *MPC, anti-slug control, severe slug flow, real deployment, ultra-deepwater, offshore oil production.*

4.1 Introduction

In the oil and gas industry, a brownfield is a maturity stage of the production, which means that the production plateau has been reached and begins to decline. The main cause for that is the reservoir pressure loss due to the field depletion. Injection of water and/or gas are frequently used as an attempt to recover the reservoir pressure and, therefore, the production wells begin to produce the fluids injected along with the reservoir fluids. The increase in the water production has two main effects on the well flow: it increases the hydrostatic head and the probability of emulsion formation. The emulsion increases the viscosity of the liquid, generating more friction in the flow. The association of a drop in reservoir pressure, water production, and emulsion formation are factors that reduce the energy available to transport reservoir fluids to the surface facilities. As a direct effect, the well begins to produce less until it stops producing by natural flow.

A commonly used practice to aid the production flow is to use artificial lifting methods, which aim to supplement the energy required to keep the well producing. The most common artificial lift technique is known as gas lift and consists in injecting gas at the base of the production column, leaving the fluid column lighter.

The gas lift applied, the increase in the water fraction produced, and the well pipeline arrangement create propitious scenarios to the formation of marginally stable flow patterns. The flow pattern in the limit cycles, also known as slug flow, may have different formation mechanisms and consequently different degrees of intensity. When the oscillations in the flow present high amplitude and low frequency, the phenomenon is rated as a severe slug. Details on the main slugging mechanisms are described in several studies in the literature[1,2,3,4,5,6,7,8,9].

Limit cycle produces flow and pressure waves and consequently increases the risk of operational discontinuity due to the activation of safety layers by high pressure10. When the operational risk is imminent, it is customary to restrict the well's production by partially closing the topside choke valve. This action might stabilize the flow[1,6,11], but it also increases the well's back pressure, which tends to sacrifice production potential in order to ensure operational safety. Another implication of the limit cycle flow is the loss of production inherent to the oscillation[12]. Theoretical studies carried out by Hu and Golan (2003)[13] and Hu (2004)[7] showed that the operation in the limit cycle can reduce the production of an oil well by 20-40% when compared to the theoretical equilibrium.

In Diehl et al (2018)[14], a gain in oil production of around 45% was verified when comparing an open-loop operation to a closed-loop one. In this case, the well was kept in an equivalent operational point inside a slug flow region in both situations. This result means that the production recovery was totally due to the approach of the stable equilibrium from the limit cycle pattern. Despite that, the gains in production are always linked to the combination of reservoir and well system characteristics. The best approach to estimate the potential gain consists of building the correspondent bifurcation diagram of the production system and map the equilibrium point of the limit cycle branch, as illustrated further.

This work addresses a real ultra-deepwater well that shows instability patterns depending on its operational condition. The problem is treated through an APC solution that allows it to operate in an unstable equilibrium branch resulting in oil production increase.

4.2 Background

One of the first methods to control severe slugging in offshore production systems was by increasing the topside back pressure as descripted by Yocum (1973)[15]. The author described three field observations in the 1960s where the solution to eliminate slugging was to close the choke valve in the topside facilities. As a result, it was observed that the wells lost around 60-70% of their potential production. Schmidt et al.[1,16] confirmed the choking as a method to eliminate severe slugging in an experimental facility claiming it was possible to keep lossless flow rates when the well was properly choked. In that case, the authors crossed a bifurcation point when the choke valve was closing. In the mathematical theory of bifurcations, if a system changes its qualitative behavior (stability) or its number of steady-state solutions, it is referred to as bifurcation behavior[17]. If a limit cycle is formed when a parameter is varied it is called Hopf bifurcation and if this limit cycle is stable, it is rated as a supercritical Hopf bifurcation[17]. A slugging is formed by a supercritical Hopf bifurcation, and it occurs in multiphase flow when the choke valve opening (more precisely by the backpressure imposes by the valve) crosses the Hopf point from stable branch of equilibrium to a stable periodic solution branch. So "properly choked" meant to stay very close to the Hopf point but on the stable branch of the equilibrium. Obviously, it is harder to get that in a real oil well once the laboratory facility is a better controlled environment. Beyond that, the authors' conclusion relies on the Hopf point locus and this is a consequence of the well setup and its flow conditions.

The first approaches considering feedback control to stabilize the flow in oil wells came to light in the 1980s[2,18,19,20]. Nevertheless, the works were purely theoretical and there was no field deployment. In 1990s the Elf Aquitaine company disclosed the first field implementations of automated operational procedures at Gonelle Field, Gaban. The aim was to increase the oil production and decrease the gas injected by acting automatically on the choke valve opening and the gas lift flow itself[21,22]. According to Gaurnaud et al. (1996)[22], the gains observed were of about 20% in oil production and a gas injection reduction. Jansen et al. (1996)[6] also pointed out the combination of choking and gas lift as the best way to eliminate slugging, making it possible to reduce the gas injected required and the choking degree in an experimental facility.

A project to eliminate slugging by active control was performed by Total Petroleum Company in the middle of the 90s as reported by Coubort (1996)[23]. The occurrence of severe riser-induced slugging in Dunbar to an Alwyn multiphase pipeline was causing serious and troublesome operational problems within the receiving process facilities. Dunbar is a collecting platform that transfers oil and gas along a 22 km subsea pipeline to the Nab processing platform. The whole production system is in shallow water between 150-200 m in depth. For the purpose of eliminating slugs, a PID was used to control the riser base pressure 150 m away from the Nab platform, acting in an additional control valve installed, bypassing the normal choke valve. The system philosophy is a kind of override between open-loop and closed-loop: when the flow or the GOR (gas-oil ratio) is low, the production through the control branch and the controller acts to suppress the slugging, while if the flow or GOR is high, then the flow becomes stable, and the normal choke valve is used in open-loop. Although the author confirms the success of the strategy, the implementation and results are poorly shown in the paper, and even the control actions are not present.

Hence, maybe Havre et al (2000)[24] could be considered the first feedback control applied in field at a British Petroleum (BP) production unit, Hod-Valhall site in the North Sea. Hod and Valhall were two shallow water platforms (70 m deep) connected by 13 km of pipeline. Hod works as a header to many wells while Valhall processes the total multiphase flow from Hod and other wells. The slugging verified in this situation was caused by a terrain-induced mechanism. A control solution was developed by ABB and BP to deal with the slugging and its structure considered flow rates and pressures measurements as input to the control system. The manipulated variable in Valhall was the choke valve. Results showed a reduction of the instability pattern caused by slugging when the controller was acting. Havre and Dalsmo (2001)[25] presented an extended evaluation regarding the Havre et al.[13] work. An interesting point is the authors reinforce the fact that the only two platforms to apply a closed-loop in a multiphase pipeline, as reported until 2001 by the offshore industry, were Dunbar-Nab24 and Hod-Valhall[25]. According to Havre and Dalsmo (2001)[25], one reason for this is the lack of integration among the control engineers and the petroleum engineers responsible for the multiphase flow issues. Indeed, this is a problem that has not even been overcome nowadays since the control theory is not a topic suitably explored by petroleum engineers.

Skofteland and Godhavn (2003)[26] presented the first tested anti-slug control strategy for a Statoil field. The control installation was completed in 2001 at the concrete tension leg platform (TLP) Heidrun (350 m deep) located in the Norwegian Sea. Severe slugging in the platform riser was experienced through long multiphase flowlines (4 and 7 km). A cascade control strategy was used to deal with the slug flow. The purpose was stabilizing the production flow using the choke valve in topside as a manipulated variable while pressures and flowrate were used as controlled variables. As a result, the authors show that the slugging was suppressed, and the flowline pressure was reduced. Unfortunately, despite the success, the applicability of the strategy is a bit limited since the control structure requires multiphase flow measurements, which is not always available in production systems, especially if the scenario involves satellite wells. Extended studies were performed in SINTEF's experimental loop at Trondheim and its results are shown in Godhavn et al. (2005)[27].

A very interesting application was reported by Daslmos et al. (2002)[28] from ABB in Brage field located in the northern part of the North Sea. With a water depth of around 140 m, the Brage field was operated by Norsk Hydro and its production began in 1993, reaching its plateau in 1998. Thereafter, the production system has experienced problems with unstable flow in the wells. A feedback control solution was deployed to stabilize one of the wells using the production choke valve at the wellhead. The controlled variable was the downhole pressure. No details regarding the control algorithm were shown in the paper, however the results are well described. The controller allowed an increase in the valve choke opening and a decrease in the well downhole pressure. The authors estimated a reduction of about 75-100% on the oscillations while the controller was turned on. Differently from Dunbar-Nab[23], Hod-Valhall[24] and Heidrun[26], where the deployments were in the connection pipeline between two facilities, the Brage field application was performed directly in the well.

Several studies regarding active control strategies for slugging have been reported in the literature over the last 10-15 years[29]. It is worth highlighting that there are basically three main arrangements addressed in these works:

(1) onshore or shallow water wells, which consist in the production column and gas lift annular as a system;

(2) platform interconnection or subsea manifolds that stand for pipeline-riser systems; and

(3) deepwater and ultra-deepwater wells consisting in a well-pipeline-riser system, which is the most complex scenario since it is like a shallow water well (1) integrated with a pipeline-riser set (2).

Considering the multiple arrangements and their measurement availabilities – flowrates and pressures in different points– there is a large combination of input variables to be considered in a control structure. Perhaps the greatest consensus among the author is the use of topside choking as the main manipulated variable.

In order to discuss the main conclusions regarding control structures, some of the previously defined arrangements (1) and (2) works were chosen. When the system is composed by a production column and a gas lift annular, the best controlled variable is the downhole pressure[30,31,32,33], while if the system consists of the pipeline-riser arrangement, the best controlled variable is the pressure in the riser base[34,35,36,37,38,39]. In the second scenario, the pressure difference between the base and the top of the riser could be an effective alternative as a controlled variable[37], despite the fact that this structure requires two sensors instead of one.

Although the best variables for control purposes are the subsea or under seabed pressures, these measurements, however, are not always available. Hence, a research line aiming to investigate how to estimate pressures unavailable in the production system[30,31,37,39,40] has emerged. There are a lot of challenges to overcome this sort of approach and more effort is required to see how these strategies behave in real environment.

An alternative option would be using the surface measurements to directly design a controller. The topside meters are frequently more at hand than under surface ones since the maintenance is easier on the platform. However, control structures considering these measurements are reported as more limited if compared with the best control structures mentioned above[30,32,33,34,36,37,38]. Despite these limitations, combining different surface variables such as pressure and flowrate for example, might provide stabilization of the multiphase flow[30,33,38,41].

The well-pipeline-riser system, which is equivalent to the arrangement (3), represents a typical architecture of a deepwater/ultra-deepwater well, which is one of the last technological frontiers of the petroleum exploration industry[29]. Even so, few works have addressed analysis to system (3) as mentioned for scenarios (1) and (2). Considering topside choking as a manipulated output, the best controlled variable for system (3)[38,42] is the bottom hole pressure since the static gain is larger than other pressures. Inspired by Jansen et al.[6] that shows an open-loop study where the best elimination method for a pipeline-riser slugging was combining choking and gas lifting, Diehl et al.[14] and Gerevini et al.[43] explored the use of those two manipulated variables through a nonlinear model predictive controller in a well-pipeline-riser system. The controlled variable was the bottom hole pressure as this measurement expresses the stability essence of the flow while it indicates the level of total production in the well. The results show that it is possible to suppress slugging and increase the well production even if a slow choke valve is used. Furthermore, the manipulation intensity tends to decrease in the multivariable structure.

The main advances in the latest works[14,30-43] are within the theoretical field since few real deployments are reported in the industry. Petrobras has applied the Skasiak et al.[44] algorithm for anti-slug control, whose idea is to suppress the oscillation while the choke valve opening is maintained operating around a desired opening value. As a field result, 1-2% of production was increased through improving stability, avoiding shutdowns and flaring[45,46,47].

Though Diehl et al.[14] and Gerevini et al.[43] address MPC solutions to deal with unstable wells, so far there have been no practical validations since no deployment has been performed. So, the aim of this work is to describe a real field-tested MPC approach to deal with slugging in well-pipeline-riser systems.

4.3 The Real Oil Well Description

The RO_X is a generic name of a real well from Petrobras located in Campos Basin which is installed in an ultra-deepwater region (water depth of 1850 m). This well is linked to a semi-submersible platform that produced its first oil in 2007, rating it as a brown field production system. Currently, the oil produced by this platform has a density of 28° API and a BS&W (Basic Sediments and Water) of around 65%.

Figure 4.1 presents the dimensions of RO_X where the continuous line indicates the subsea pipeline-riser, and the discontinuous line represents the production column under the seabed. This well shows a limit cycle production flow behavior depending on the operating conditions. Figure 4.2 shows some operational situations of the RO_X well represented by the downhole pressure measured in the PDG (Pressure Downhole Gauge): from the marginal stability (a) to the Hopf point transitions induced by the variation of the choke valve opening (b,c).

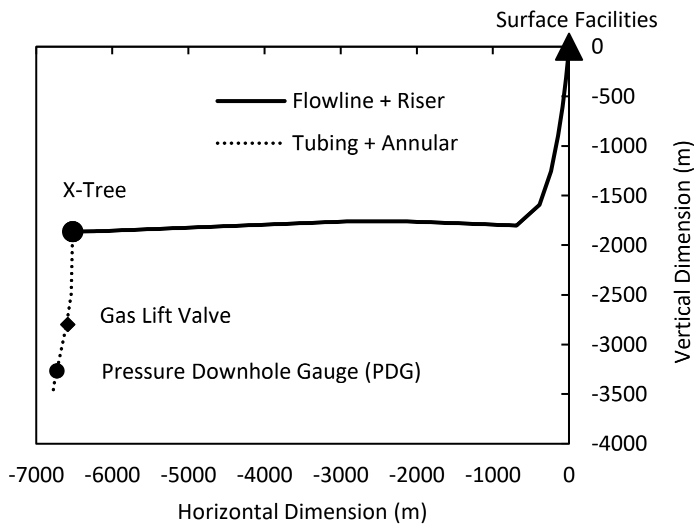

Figure 4.1 – Ultra-deepwater RO_X well dimensions.

Due to slugging appearance when the topside back pressure is reduced, the well operates with the restricted production choke valve by opening values between 30-40%. In case of severe slug, the choke valve is closed to restore the operation stability. Figure 4.3 illustrates this operational limitation in the well over a year of operation.

Based on historical data from the well, it was possible to select scenarios for the construction of an estimated bifurcation diagram, which is presented in Figure 4.4. In this diagram it is possible to verify the existence of a Hopf point, which indicates a qualitative change in the dynamic behavior of the system between 30-40%. To the left of the Hopf point there is a monotonically stable equilibrium branch, while to the right of this bifurcation is a branch of marginally stable equilibrium. For the usual gas lift flowrate, the Hopf point is located about at 33-34% of choke valve opening. However, it is known that variations in gas lift flowrate can move the Hopf point. Other variables also change the Hopf bifurcation locus, but not as fast as the gas lift does. For this reason, the operating staff positions the choke valve more open or closed, but always within the 30-40% opening range.

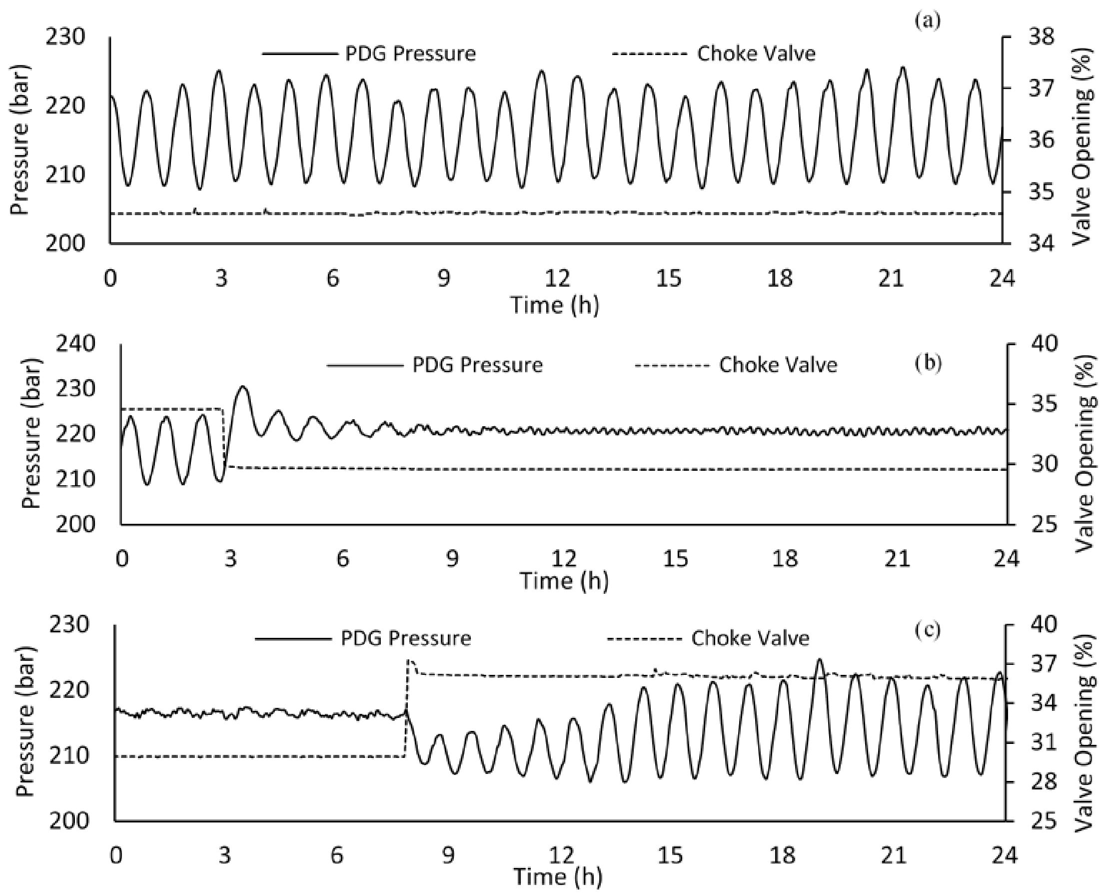

Figure 4.2 – Well operational history: (a) limit cycle; (b) stabilizing the flow by reducing the opening of the choke valve; (c) loss of monotonic stability by opening the choke valve

The control strategy designed in this work aims to push the Hopf bifurcation to the right side as much as possible while reduce the oscillation amplitude of the limit cycle, making it possible to achieve lower pressures in downhole safely, which means increasing the production. The next section is dedicated to the control strategy description.

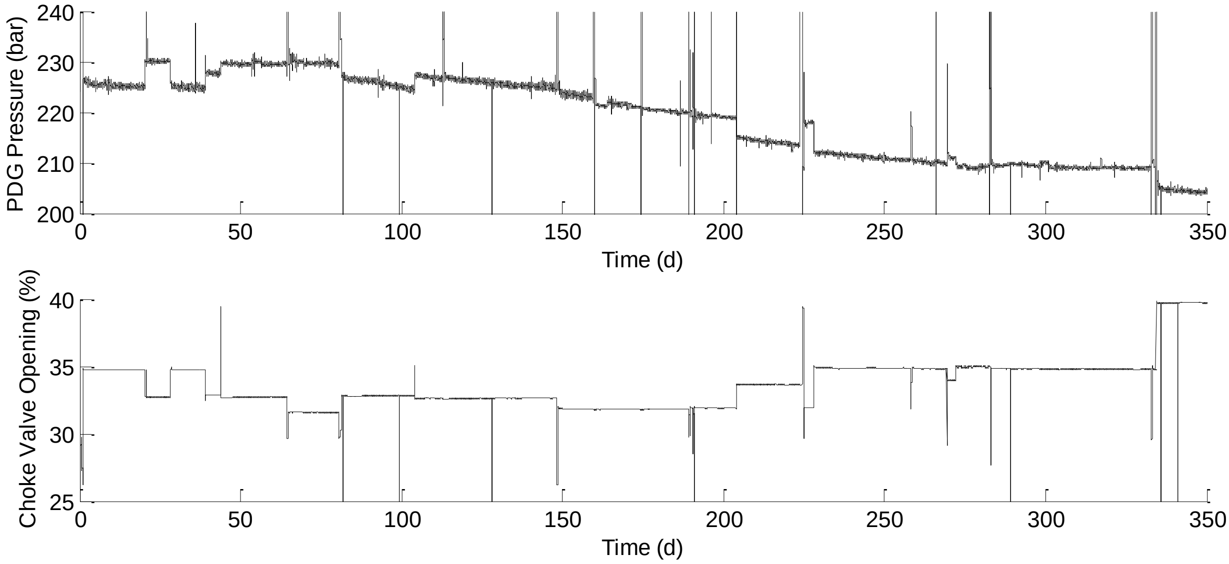

Figure 4.3 – Actual well operation with choke valve opening restricted to ensure flow stability.

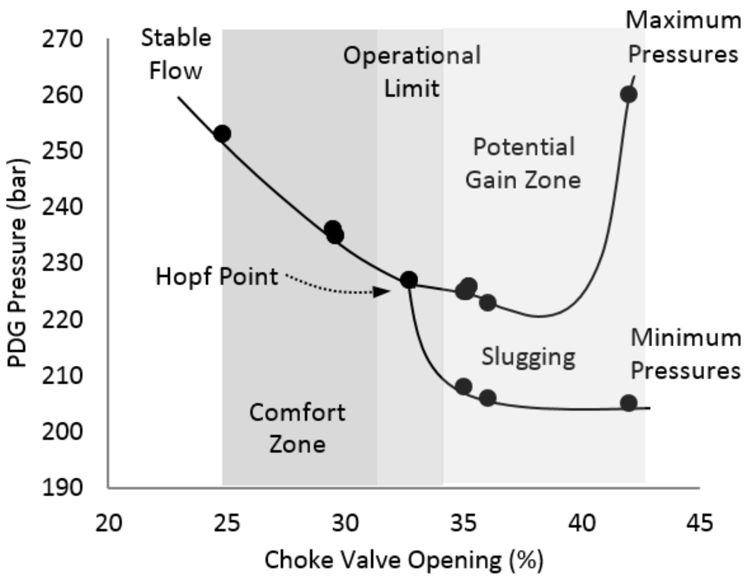

Figure 4.4 - Bifurcation diagram based on actual data from RO_X.

4.4 APC Strategy

The control structure used in this work is composed by the pressure measured on the PDG and the topside choke valve as the controlled and manipulated variable, respectively. The downhole pressure combines two crucial operational information of the well: the flow stability and the oil yield. Furthermore, this pressure is pointed out in literature as the best measurement for anti-slug active control[38,42], as previously discussed in this chapter. An automatic choke valve is available on the topside facilities as a manipulated variable, which makes it a natural choice for the controller. This valve is equipped with a stepping actuator with 350 steps. Since the estimated actuator movement rate is 1 step/s, the stroke time of the choke valve is around 6 min.

The control strategy proposed in this work is composed of an MPC associated to a PID, according to Figure 4.5. The MPC objective is to lead the PID by an optimal transient up to the desired downhole pressure at the same time as the MPC action in the choke valve has an anticipatory role, such as a feed-forward system. The PID is responsible for the regulatory characteristic and to increase the controller robustness, playing the stabilization role in the control loop and rejecting disturbances. Disturbances in the wells are common in daily operation. For instance, in an oil rig there are subsea manifolds providing gas to the wells. These manifolds suffer unmeasured disturbances since each manifold provides gas to 6-8 wells. This linked configuration associated with a low subsea capacitance makes the gas distribution a highly integrated system where variations in the compression plant or in the gas consumption of the wells propagate to all other wells. Besides that, in the present study, the gas lift flow meter was unavailable. In this scenario, the PID is a key element for the implementation robustness. An example of an unmeasured disturbance, probably triggered by the partial loss of the gas lift supply, can be seen in Figure 4.6. The well production was stable when suddenly an oscillation comes up, while the choke valve was maintained constant.

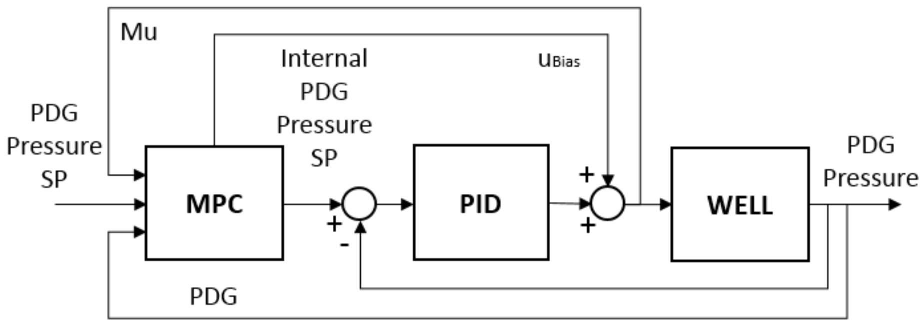

Figure 4.5 – Two layers control strategy deployed in RO_X well.

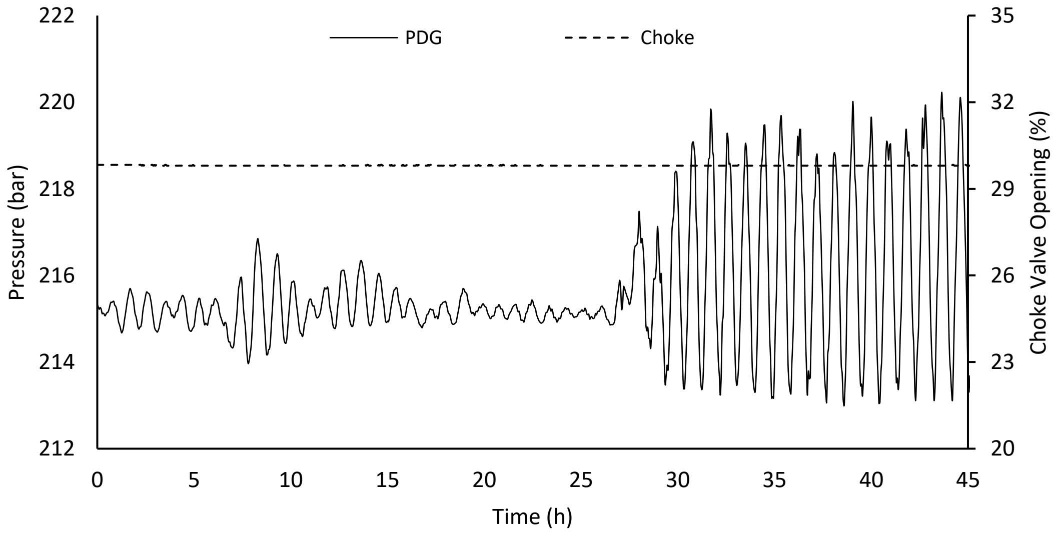

Figure 4.6 - Unmeasured disturbance initiating a high oscillatory cyclic behavior.

In Diehl et al.[14] a nonlinear model of predictive control manipulating the choke valve and the gas lift flow rate was used to control the downhole pressure. In that work, a nonlinear ODE model called Fast Offshore Wells Model (FOWM)[48] was employed. In the current deployment, a linear MPC was chosen due to three main reasons: firstly, the gas lift flowrate is not available to be used as a manipulated variable; secondly, the authors did not intend to change the operating point in a wide range, so a linear controller might achieve a satisfactory performance; and finally, to keep the solution as simple as possible – definitely fitting a nonlinear model such as FOWM for available plant data that is not straightforward.

A dataset as big as one year of operation was used to analyze the well's dynamics. A set of linear models in the stable branch (pre-Hopf) were identified based on autoregressive exogenous models and operational data from the well history. Some results of this evaluation are shown in Figure 4.7. Each window corresponds to a different linear model identified and its equivalent real data. As it can be seen, the models are able to capture the PDG dynamic. The unitary step response for opening the choke valve of some models is shown in Figure 4.8. There is a considerable degree of static nonlinearity and a low degree of dynamic nonlinearity. It is worth remembering that the models depict the stable branch, and therefore the level of dynamic nonlinearity is low. The static nonlinearity is caused by the loss of gain along the valve opening, which indicates that the controllability is getting worse as the valve opens. This means a linear controller tends to lose its performance as the downhole pressure decreases. Despite that, some performance can be recovered through a static gain compensation.

The Bode frequency plot of the identified models is shown in Figure 4.9. It is possible to see that the well consists of a minimum-phase system – at least at the pre-Hopf region. Furthermore, despite nonlinearities observed in Figure 4.8, a single linear controller can stabilize the system in the whole range of operational points depicted here by the set of linear models identified from the plant data. The simulation shown in Figure 4.10 presents the system stabilization through a linear incremental PID using the same set of tuning parameters. The real limitations verified in the well choke valve were included in the model: (1) the step actuator low resolution, which results in a quantization of 0.286% (350 steps between 0% and 100% of valve opening); and (2) the low-speed actuation of 1 step/s which requires around 6 minutes to totally open or close the valve. The valve quantization produces such a small oscillation in the pressure when the system is close to the set point.

In order to identify a current model for the MPC and to generate an initial tuning for the PID, an open loop step was performed in the well, as can be seen in Figure 4.11 (a). The step perturbation in choke valve was performed on the left side of the Hopf bifurcation at around 38% of the choke opening. At the time of the test, the operators were able to open the choke valve to approximately 40%. The well had not operated above this value for a long time as a result of the strong instabilities verified when it was attempted. Figure 4.11 (b) shows the model identified, which is presented in Equation 1.

$$G(s) = \frac{-8{,}404e^{-11}}{s^3 + 5{,}14e^{-3}\, s^2 + 7{,}64e^{-6}\, s + 3.48e^{-9}} \qquad (4.1)$$

The predictive controller used was the BR-NMPC[14,49] software. Although the controller allows the treatment of nonlinear problems, through a linearization strategy along the trajectory, the linear version was chosen since the objective is to operate around the open loop point close to the Hopf bifurcation. The MPC sampling was set to 90 seconds, while the prediction and control horizons were 5 and 2 hours, respectively[50,51,52]. Movement suppression and SP weight were initially determined by trial and error in a simulation stage not covered in this paper. Target, soft constraints, and state estimators were not used in this implementation. The PID implementation makes use of an incremental algorithm[53]. Its initial tuning was based on direct synthesis. A first order filter in the PDG pressure was also used.

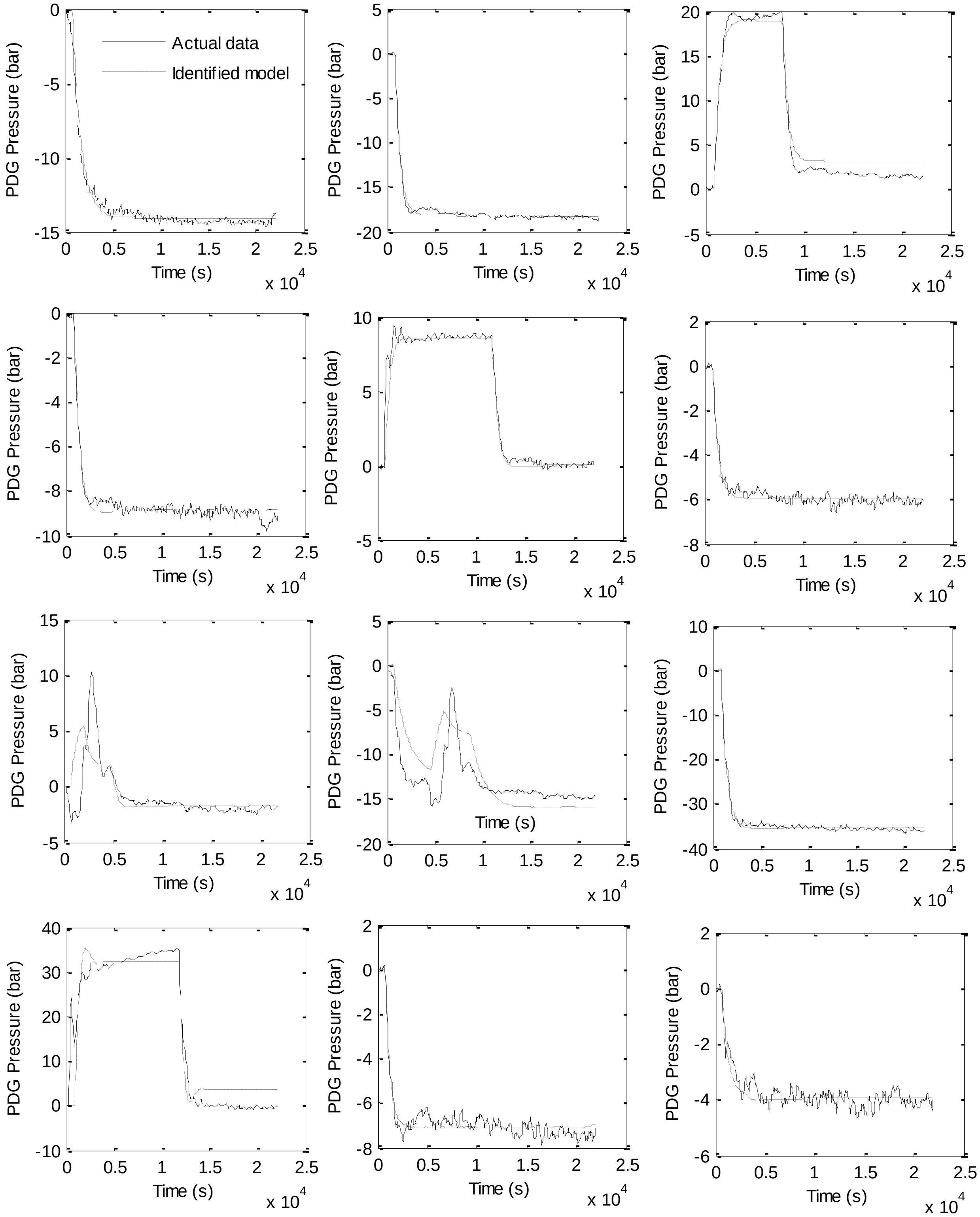

Figure 4.7 - Identified models based on the well data history.

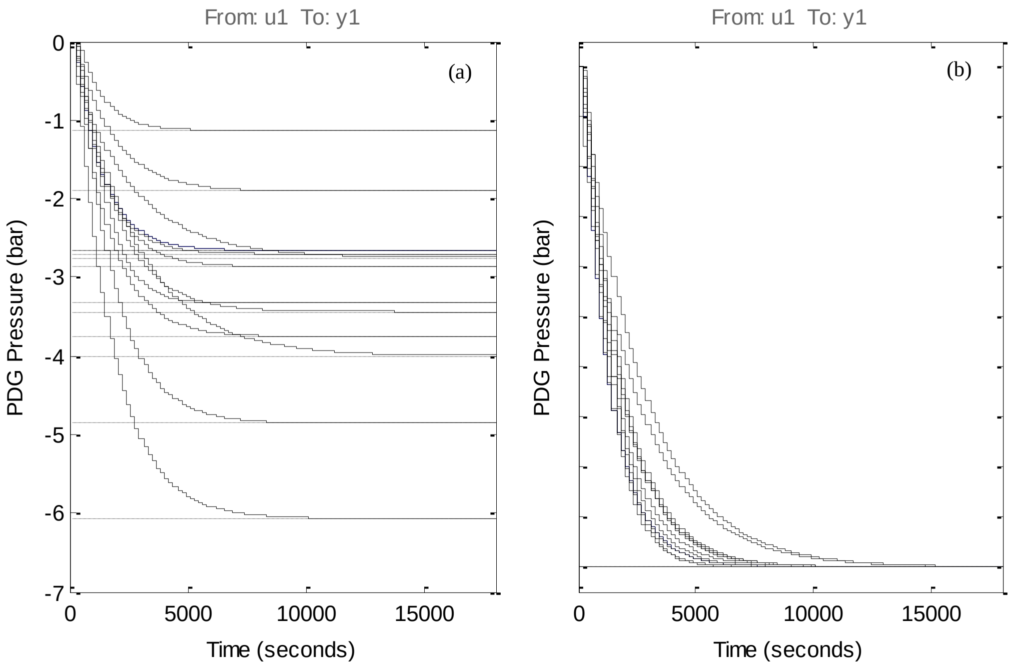

Figure 4.8 – Models response to unit step: (a) pressure on PDG and (b) its normalization by the gain.

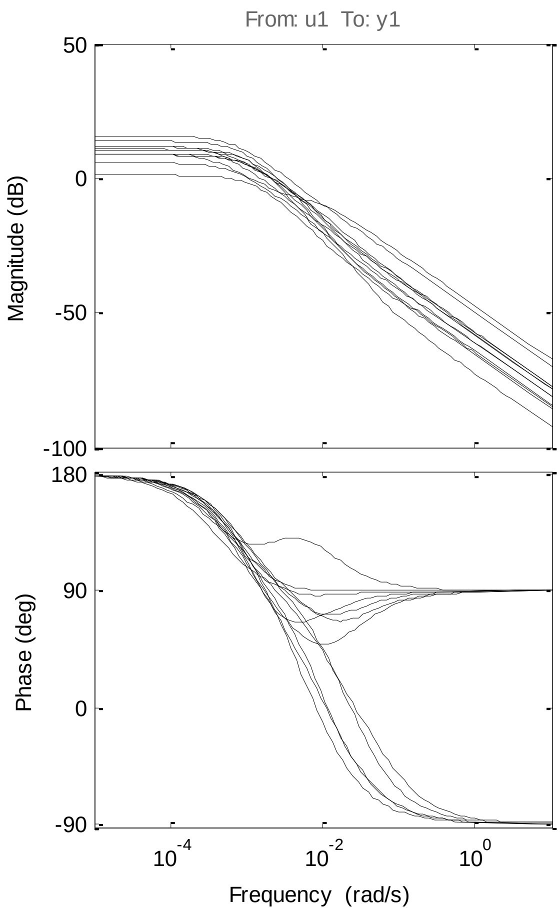

Figure 4.9 – Bode diagrams from the identified models

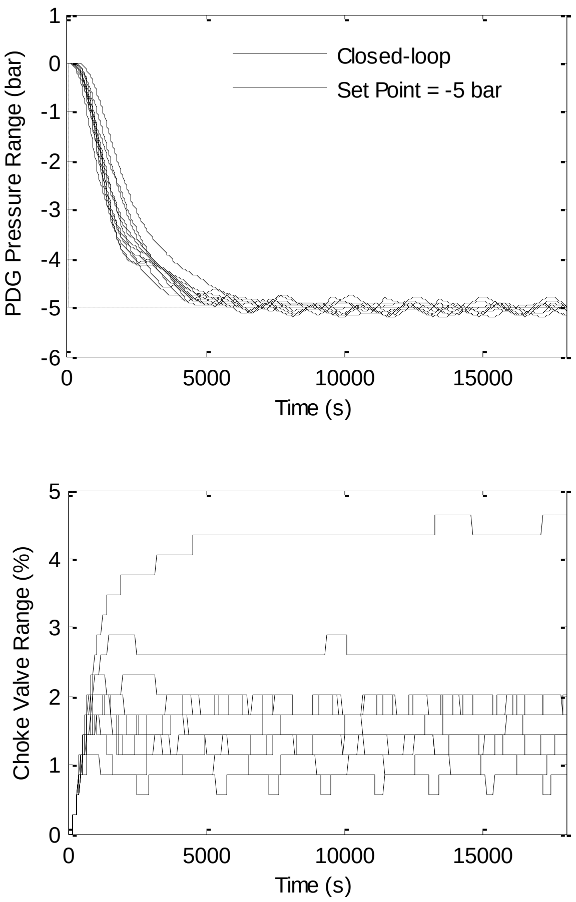

Figure 4.10 – Identified models stabilization through a linear PID.

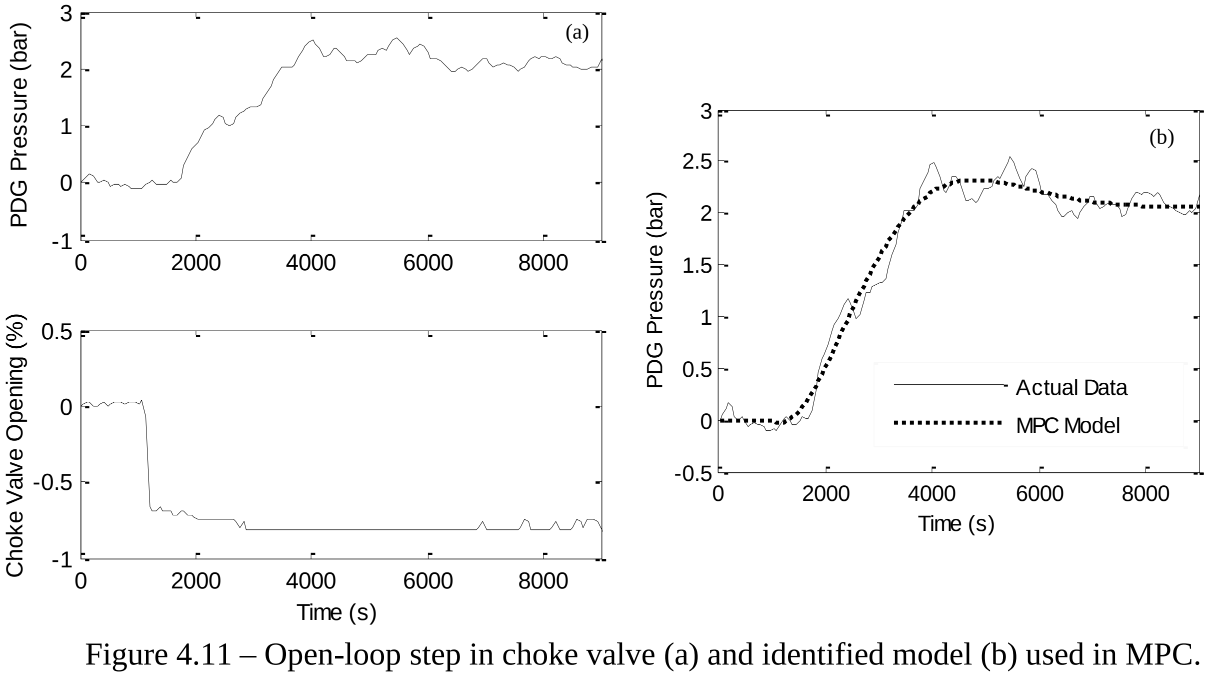

Figure 4.11 – Open-loop step in choke valve (a) and identified model (b) used in MPC.

4.5 Results

The control strategy proposed in this work was field tested in December 2017 at the platform previously described. The results are presented in Figures 4.12 and 4.13. Prior to the controller startup, the well was in a stable operational point where the PDG pressures were between 206-207 bar and the choke valve opening was restricted at about 39%. If the choke valve opening overtakes values around 39-40% in open loop, the production will experience severe slugging, which brings on operational continuity risks.

Right after the test startup, a period of about 24 hours was dedicated to evaluating the communications between the different automation layers and the control algorithm. At this period, the well was slightly pressured in order to stay at the stable equilibrium branch – since it was a safer alternative at this stage of the test. Besides this evaluation, a fine tuning was performed in the MPC and PID algorithms, as detached in Figure 4.11. The MPC was pre-configured in simulations and its final tuning was performed in loco. The movement suppression was equal to 60 and the weight of the SP error was equal to 7.5. At the end of the online verifications and settings, the PID tuning (refined by trial and error) in engineering units was: controller gain k_p = -0.4; integral time constant τ_i = 1,500; and derivative time constant τ_d = 10. The first order filter was set up with 30 s of constant time.

After the tuning period, a PDG pressure minimization procedure was initiated through progressive reductions in the set point of the MPC controller. The linear control strategy was able to keep stability in the flow, at least in the range of operational points of the test.

The total PDG pressure reduction reached was about 8.5 bar in closed loop. The choke valve opening went from 39% to an average of 46%. Considering that the well productivity index (PI) is equal to 12.8 (m^3/d)/bar, the well liquid flow was increased by 108.8 m^3/d. Taking into account a BSW of around 65%, oil production increase is equivalent to approximately 38 m^3/d or 238 bbl/d. Considering the crude oil at US $60 a barrel, the financial return of this specific APC solution would be of more than US$ 5 million a year.

The oil production in open loop was estimated based on a well test routine performed one month before the controller deployment. The production registered in this well test was 371 m^3/d of oil, which means that the oil production increase achieved through the controller in the field test was in the order of 10%. For this case, an increase of around 1.5% was observed in production for each extra opening percentage in the choke valve.

At the end of the test, the well was lightly pressurized to a choke opening of 44% and the controller was turned off at this point as shown in Figure 4.13. The beginning of an open-loop instability in the well was observed, indicating that the operating point was beyond the Hopf bifurcation. This proves that the controller proposed was efficient in stabilizing the well in the unstable equilibrium branch of the production system.

Another important point to be mentioned is the pressures around the production choke valve. Even considering different automation logics, these pressures usually trigger interlocking layers in the case of an overpressure. Therefore, their monitoring is important to ensure operational continuity. As it can be seen in Figure 4.14, the pressure upstream of the choke drops about 10 bar during the test, while the downstream pressure of the valve remains practically unchanged. Both behaviors do not imply in any safety implications for the operation of the RO_X well or to the processing plant.

There is an interdependent relationship between the temperature of the production column and the fluids produced in the well. Reservoirs usually have a constant and higher temperature, usually in the order of 60-90 °C, than the seabed or the sea environment. Therefore, the variations in the temperature of the production column indicate a change in the flowrate going through the well tubing. The temperature of the production column in PDG during the controller test is shown in Figure 4.15. Two points are important to highlight: temperature increase indicates an increment in production flow and the explicit negative correlation between pressure and temperature in PDG. Therefore, the well temperature is another indication of the flow rate increase in the production system.

An aspect that deserves attention is the difference between the choke valve opening command and the value positioned by its actuator observed in the field. The valve command is the desired value for the valve opening, either this value defined by the operator or by the controller. An error was observed in the positioning step resulting in an offset between the valve’s command and real position, as shown in Figure 4.16. Considering that the sensitivity of the choke opening variation is very high, approximately 3.5 bar/%, the error in the choke positioning, even if small, brings a negative effect for the control system. The actuator’s low resolution quantized in 0.286% (350 steps), associated with the imprecision valve positioning, is a limiting factor for the controller performance, which means that even better results can be achieved with a better final control element.

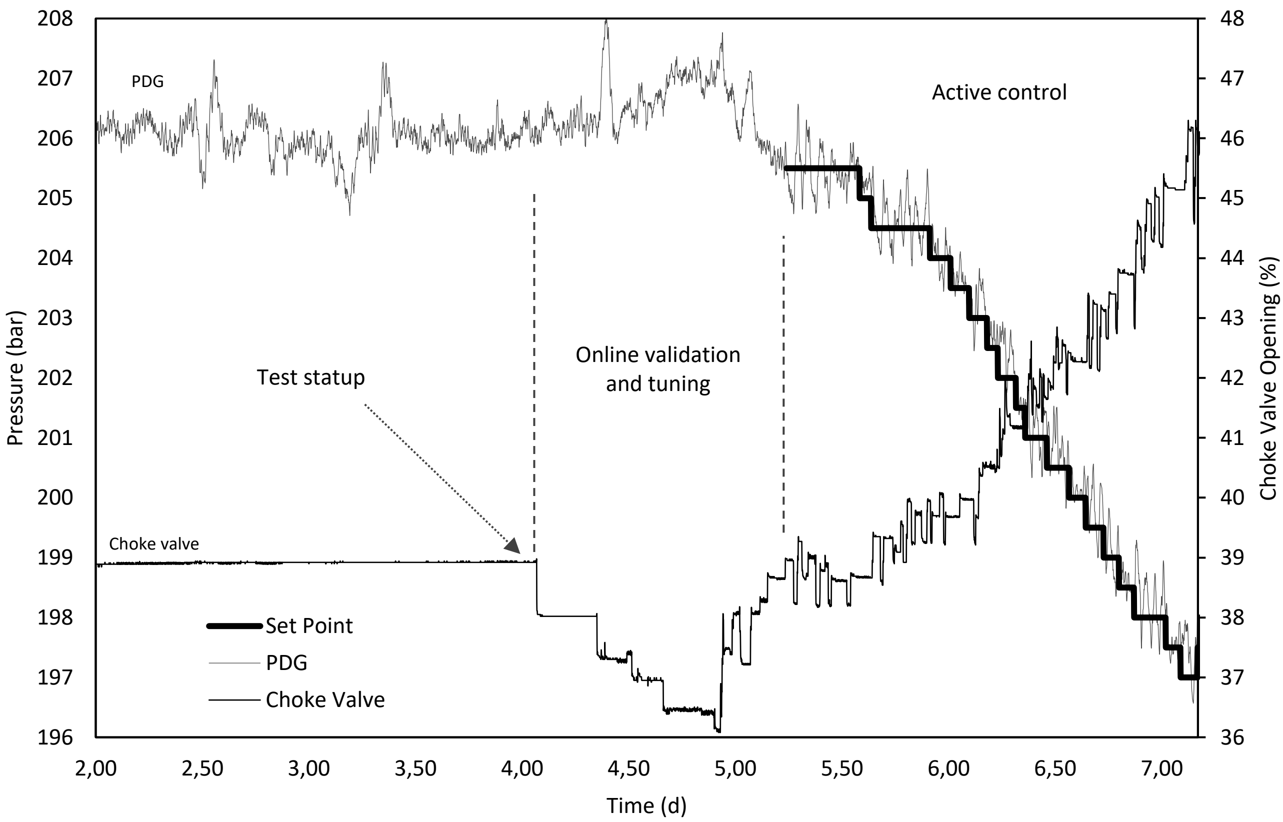

Figure 4.12 – Bottom hole pressure minimization through an APC strategy in a Petrobras real oil well.

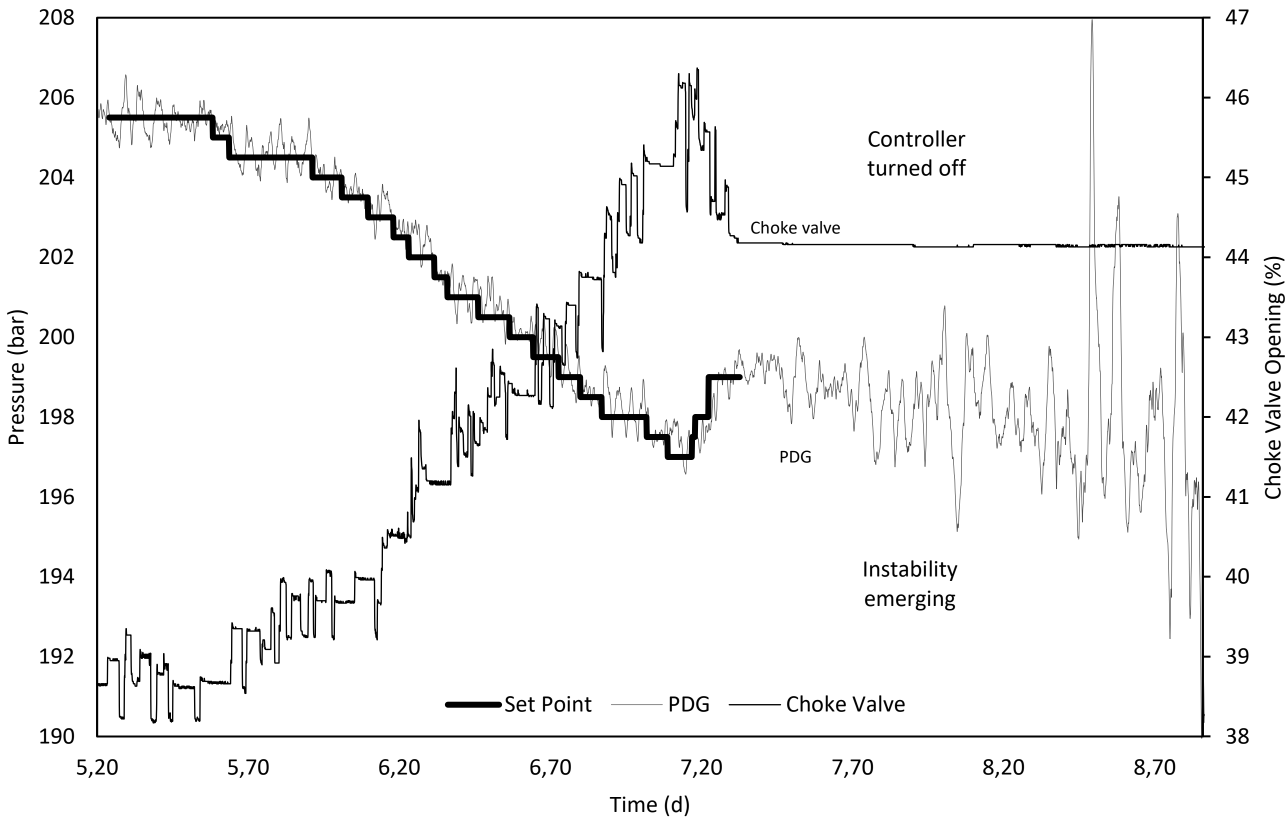

Figure 4.13 – Instability propagation in open-loop.

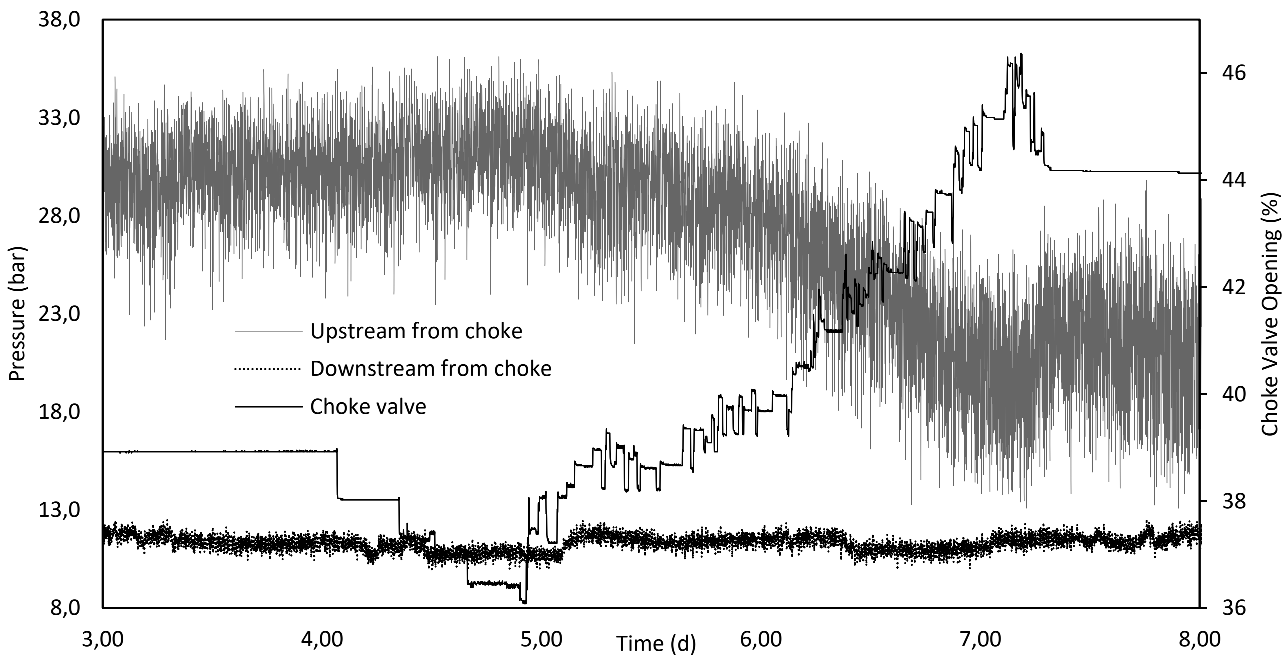

Figure 4.14 – Topside pressures around the choke valve: before, during and after the controller test.

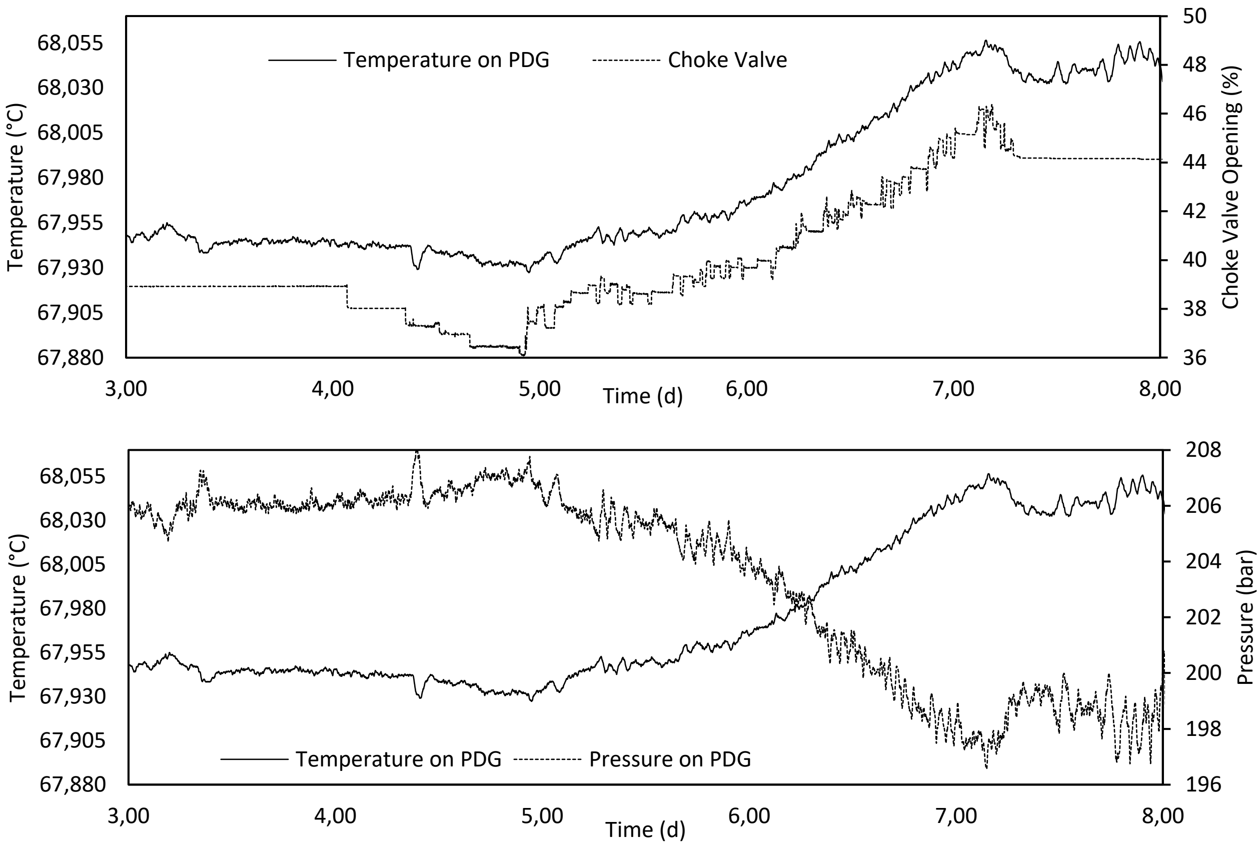

Figure 4.15 – Temperature in the production column indicating increase in well flowrate.

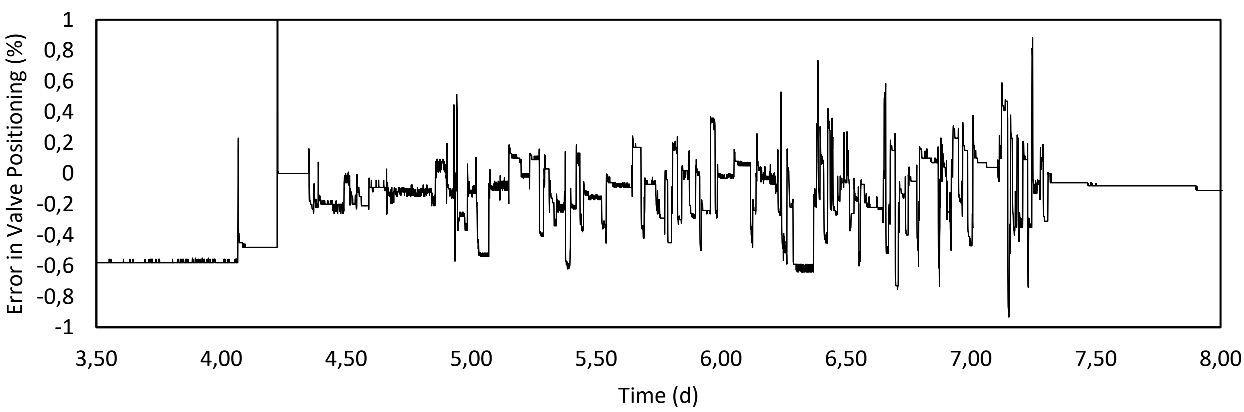

Figure 4.16 – Difference between the choke valve command and its actual value.

4.6 Conclusion

In this work, the authors have proposed an APC strategy based on MPC-PID coupling to handle instabilities in oil production wells. This strategy relies on downhole pressure and topside choke valve as controlled and manipulated variables, respectively. The system proposed was applied and validated in an ultra-deepwater field implementation at a Petrobras platform.

In the actual deployment, the APC strategy allowed the reduction of the well downhole pressure in 8.5 bar. The choke valve opening was increased in 7%, which meant a reduction of around 10 bar in its upstream pressure. The pressure reduction in the well bottom hole was the force needed to increase the oil production by approximately 10%. It is estimated that this result is equivalent to a return of more than US$ 5 million a year based on a US$ 60/oil barrel scenario.

Throughout the test, the controller kept the flow running stably. The proof that the controller went through the Hopf bifurcation point could be seen by turning off the controller in a closed-loop stable condition, which resulted in operational instabilities in the well.

As far as the authors are aware, this is the first time a predictive controller model was used to deal with a slugging phenomenon while optimizing the oil production in a real well in the offshore industry.

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Capítulo 5

Anti-slug control design: combining first principle modeling with a data-driven approach to obtain an easy-to-fit model-based control

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Abstract

The limit cycle is an unexceptional problem in the oil industry that may cause significant losses in production. Also called slug flow or slugging, the unsteady flow can be handled by feedback control, although nonlinear issues must be considered. As an oil well production valve is opened, its transfer function gain tends to decrease until it reaches zero, meaning that the valve actions lose effect against the system backpressure. Notwithstanding, this sensitivity loss can be compensated by adapting a suitable tuning according to the well operating point. In this work, a methodology to generate this control policy is proposed based on combining first principle modeling with a data-driven approach. The method aims at improving closed-loop performance through a gain scheduling curve resulting from an easy-to-fit model to plant data. A systematic procedure is defined and validated through an actual deployment in a Petrobras ultra-deepwater oil rig. As a result, it was possible to suppress unsteady flow and increase oil production by more than 9%. Although the method has been validated in a satellite offshore well, one expects that feedback control can be used in different scenarios successfully, regardless of the slugging mechanism.

Keywords: *Active anti-slug control, nonlinear control design, semi-empirical model, unsteady flow, real deployment.*

5.1 Introduction

During an oil field life cycle of production, it is likely that problems related to stability occur. These problems originate in the multiphase flow features and are more common when the field reaches a mature stage. One can say the offshore upstream sector is frequently more affected by this kind of problem once the subsea flowlines may trap gas due to terrain irregularities or negative declines between seabed lines and the riser. This occurrence creates a cyclic pattern of flow where gas is trapped by liquid accumulation, making the pressure increase until the liquid column is pushed away all the way through the production line. In the next step, a new incoming liquid joins the liquid that returns from the riser, and a new blockage occurs, beginning the cyclic phenomenon once again. If the pressure oscillation reaches high amplitude, this phenomenon is called severe slug flow, and it represents safety risks to facilities and/or disturbances to process plants. Several kinds of slugging mechanisms are widely discussed in Gilbert (1954)[1], Yocum (1973)[2], Schmidt et al. (1980)[3], Taitel (1986)[4], Bendiksen et al. (1986)[5], Fuchs (1987)[6], Torre et al. (1987)[7], Fabre et al. (1990)[8], Jansen et al. (1996)[9], Hu (2004)[10], Sinegre (2006)[11], and Eikrem (2006)[12].

Unstable wells result in production reduction. Yocum (1973)[2] describes losses in the capacity of more than 50% in offshore oil field production systems caused by poor design of two-phase flow risers. The author presents two real cases in which the slug flow formed in the vertical section was so severe that the flow capacity was reduced by approximately 60% and 70%. At that time, the offshore industry was experiencing its first severe troubles regarding slugging. Unfortunately, still nowadays, it is not possible to design an optimal oil rig because the production conditions substantially change along the field lifecycle.

Despite slugging is an old problem in the oil industry, its solution has not reached a consensus in the engineering community. One can sort the approaches to handle slugging into two groups (Pedersen et al., 2016[13]): the passive and the active methods. Passive strategies basically refer to installing equipment to dampen the slug flow. This type of solution is more common in onshore environments, since this scenario requires more area and weight for installation, and the maintenance costs are much lower when compared with the ones in offshore facilities. On the other hand, active approaches consider the use of feedback control to address the stability problem and puts an end to all that passive solutions drawback. However, active solutions require a certain degree of instrumentation and automatic actuators.

Slug flow reduces production even if it does not harm safety. Hu and Golan (2003)[14] reported around 20-40% of losses due to unstable gas-lifted system in their models. Still based on simulations, Diehl et al. (2018)[15] experienced more than 40% of the recovery in oil production stabilizing an unsteady well through feedback control. In a laboratory scale at Shell R&D facilities, Kinderen and Dunham (1998)[16] showed production rates increase of more than 40% by active control applied to an unsteady well. Considering a real scale test, Diehl et al. (2019)[a,17] depicted a feedback control deployment in a Petrobras ultra-deepwater well that obtained a 10 % increase in oil production.

As a matter of fact, it is impossible to exactly assess a global average of production losses caused by unstable flow once this number relies on a lot of conditions, such as reservoir pressure, production index, water cut, gas-oil ratio, emulsion formation, and so on. Despite this, it is possible to say that the problem is still underestimated and that the potential locked behind it might be quite relevant to the industry.

Diehl et al. (2019)[b,18] present three active control strategies to slug flow: a linear PID; a nonlinear PID; and, finally, a linear MPC-PID. The MPC-PID strategy has shown smoother actions and transitions between set points, and it was validated in a real deployment present in Diehl et al. (2019)[a,17]. The nonlinear PID has allowed the system to reach the lowest back pressures in well simulations, which results in higher oil production. Considering that the nonlinear PID compensation rule is not trivial to define, this paper aims at proposing a systematic methodology to nonlinear anti-slug control design. The procedure described making use of first-principles modeling coupled with a data-driven approach to offer a straightforward way to design a gain scheduling based anti-slug controller. As far as the authors know, this problem still was not addressed by this kind of approach in literature.

This chapter proposes a new method to design anti-slug controllers based on first principles modeling and plant data. The major contribution of the method might be the ease to fit the proposed semi-empirical model to real data, which is usually a complex task in practical multiphase flow problems. As a result, the whole well pressure steady states can be quickly mapped and used in the most diverse ways. In this work the main propose is to produce a control tuning compensation as close as possible to the nonlinear well behavior.

The control strategy aims to handle riser-induced slugging, once this mechanism usually induces the most severe unsteady flow patterns in an oil production system. However, the method might perform properly for any kind of slug flow mechanism. This is because the controller synthesis relies on the steady state well pressure and this behavior is independent of the slugging nature. The further field application reinforces this statement, since in actual production there is no way to be sure of the origin of the instability - here the slugging is likely a riser-induced type, but there are potential contributions from terrain-induced and hydrodynamic slugging as well. Regardless the slugging mechanisms and its combinations, the control strategy has shown suitable performance to deal with unsteady wells.

The chapter is divided into five sections: (5.2) overview about active control in unstable wells; (5.3) description regarding the suggested control design systematic; (5.4) simulated control performance assessment; (5.5) validation deployment in a real oil rig, which has resulted in more than 9% increase in oil production; and (5.6) final considerations.

5.2 Background

Most oil wells will experience some types of instabilities at some point in their lives, whether in an onshore or offshore environment. In the 1950s, Gilbert (1954)[1] reported what seems the most popular way to avoid unsteady flow in gas lifted wells: increasing its backpressure by choking the flow. In order to increase the flowrate of wells that have been beaned back to avoid slugging, the author mentions a device called "intermitter control". The intermitter control was a kind of mechanical device which opens or closes the production valve relying on the pressure in the gas annulus. Essentially, the idea consisted of moving the valve to an open position if the pressure was high and to a closed one if the pressure was low. Although the concept resembles a sort of sketchy feedback controller, according to Gilbert (1954)[1], intermitters have been misapplied mostly by difficulties in selecting the setting ranges.

Subsequent years were concentrated on the development of correlations to predict and model slug flow (Yocum, 1973[2]; Schmidt et al., 1980[3]; Brill et al., 1981[19]; Taitel, 1986[4]; Bendiksen et al., 1986[5]; Fuchs 1987[6]; Torre et al., 1987[7]; Blick et al., 1988[20]; Asheim, 1988[21]). Mathematical demonstration for the success of choking to stabilize steady-state flow was also reported years later by Taitel (1986)[4]. Finally, by the end of 1980s, Blick et al. (1986)[22] and Blick et al. (1989)[23] published a work that seemed to be the first one to approach the unsteady flow problem from the perspective of the feedback control theory. The instability addressed by these works is called heading and it is a flow regime characterized by cyclic changes in pressure at any point in the tubing string. The authors employed a simplified model of feedback-controller for unsteady flowing oil wells to evaluate stability through root locus analysis. The conclusions have shown that unsteady flowing oil wells could theoretically be stabilized through feedback control. Besides that, the authors stated that a PD controller is the most useful and effective configuration to stabilize oil wells.

Total SE company has developed an automatic operating strategy to eliminate riser-induced slugging phenomenon (Coubort, 1996)[24]. The strategy was applied in 1994 in a North Sea field and was based on throttling the pipeline sufficiently to maintain the pressure at a certain level to prevent liquid blockage at the riser base. In other words, they automated the choking method (Gilbert, 1954[1]; Taitel, 1986[4]) to prevent slugging. Besides, a bypass in the choke valve to deal with low flowrates, which consisted of a kind of passive method to handle the unsteady flow, had to be installed.

When field solutions were not based on production choking, they relied on gas lift rate increase (Jansen et al., 1996[25]). Nevertheless, usually, those kinds of solutions were not accepted for a long time, due to limited gas availability or due to backpressure increase, which causes efficiency loss. Some works in the 1990s suggest ensuring stability through automatic gas lift relocation. Shell verified in a laboratory-scale rig a potential increase of 40% in production through a real-time strategy to automatically distribute lift gas to the wells to maintain the system stable (Kinderen and Dunham, 1998[16]). Companies like Elf Aquitaine Production and Elf Congo reported results between 5-20% of oil increase using this strategy in an offshore field in Gabon (Lemeteyer et al., 1991[26]; Gaurnaud et al., 1996[27]). Jansen et al. (1999)[28] brought to light more details regarding the concept behind the Gabon tested technology: a model-based controller aimed at positioning well(s) in a profitable stable equilibrium through concomitantly acting on the choke valve opening and the gas lift flowrate. Despite the elegant idea, this kind of strategy does not confront instabilities, but avoid them, leading the operating point to an open-loop stable region.

In the year 2000, the first feedback control was applied to an actual oil well managing to counteract the unsteady flow in its essence (Havre et al., 2000[29]; Havre and Dalsmo, 2001[30]). The deployment was done at a shallow water British Petroleum (BP) oil rig in the Hod field, North Sea, and was able to reduce riser-induced instability in a multiphase transport pipeline through active control. The control structure considered flowrate and pressures as measurement variables and the topside choke valve as the manipulated variable.

Skofteland and Godhavn (2003)[31] have shown the application of three control structures proposed by Statoil to terrain-induced slugging suppression in a subsea manifold riser. The control structures make use of (1) subsea pressure, (2) topside density and pressures, or (3) an association of all these measurements as the controller input and choke valve opening as the controller output. The strategies were evaluated experimentally both at a medium scale loop and in a real scale in Heidrun Field in North Sea. As a result, the authors showed that the strategies could suppress the slugging, and the flowline may be depressurized to some extent. Additional discussions and evaluations are conducted in Godhavn et al. (2005)[32].

Another real interesting application was reported by Dalsmo et al. (2002)[33] in Brage field, North Sea. Located in a shallow water zone, the Brage field was operated by the former Norsk Hydro ASA. Unlike the reported cases of BP and Statoil, the production system had experienced stability problems in satellite wells caused by terrain-induced slugging. That was the first time the feedback control solution was deployed directly to a production well. The control structure considered the downhole pressure as the controlled variable (CV) and the wellhead choke valve as the manipulated one (MV). Not many details regarding the control algorithm are shown in the paper. However, the results are well described. The controller allowed an increase in the choke valve opening and a decrease in the well downhole pressure, which resulted in a production increase. The authors estimated a reduction of about 75-100% on the oscillations while the controller was active.

The actual implementation accomplishment seems to have been the driving force for several theoretical studies reported in the literature over the last years. Indeed, those real deployment feedback control lacked a comprehensive analysis, and some works emerged to fill that gap. Based on controllability analysis, Storkaas (2005)[33] thesis offers a relevant analysis about riser-induced slug flow highlighting the influence of the type and location of the measured variables used in the control structures considering the subsea pipeline up to the surface facilities. According to the author, the best controlled variables are the pressures located at subsea - inlet flowline or riser bottom - while combinations taking into account, the topside measurement can also be used. The second option is not as straightforward as the first one and usually requires non-conventional measures to achieve good performance (Silvertsen et al., 2008[35]; Silvertsen et al., 2009[36]; Silvertsen, 2010[37]). Despite that, Jahanshahi et al. (2017)[38] proposed a control strategy based on topside measurements where a virtual flow meter is used in a cascade with the choke valve pressure drop. As a result, the authors could conjugate a simple strategy and fair performance in a laboratory rig.

Eikrem et al. (2008)[39] proposed different control structures to heading instability in a production column boosted by a gas lift system. The authors stated that bottom hole pressure and annular gas pressure could be directly used as a controlled variable with good results, whereas using only topside measurement produces poor performance. Hansen (2012)[40] confirmed the bottom hole pressure as the best choice to stabilize a production column.

Problems regarding the maintenance of sensors in remote locations and difficulties with topside control structures have led to attempts in using state observers to estimate underwater measurements (Eikrem et al., 2004[41]; Scibilia et al., 2008[42]; Di Meglio et al., 2012[43]). The results are positive at some point, but the system nonlinearity makes the problem nontrivial (Scibilia et al., 2008[42]). The models may not be representative for a large range of operating points on a real well, and the stability may not be guaranteed (Di Meglio et al., 2012[43]). According to Jahanshahi et al. (2017)[38], if only topside pressures are available, the fundamental controllability limitation associated with the right half-plane (RHP) zeros cannot be bypassed by an observer.

Static nonlinearity has shown to be a relevant issue to anti-slug control robustness. For this reason, nonlinear control strategies to avoid slugging in offshore oil rig were proposed by Jahanshahi and Skogestad (2017)[44]. In Jahanshahi and Skogestad (2017)[44] work, it was demonstrated that a gain-scheduling controller is more robust to deal with the unsteady flow than other strategies evaluated. Diehl et al. (2019)[b,18] compared a linear MPC-PID strategy against a nonlinear gain-scheduling PID. The results suggested that the nonlinear strategy may reach lower back pressures in the well. However, the MPC-based strategy showed less variability in the controlled and manipulated variables. Thus, the MPC was field applied in an ultra-deepwater well resulting in oil production increase of 10%. These results are depicted in Diehl et al. (2019)[a,17]. A nonlinear model predictive control (NMPC) was also addressed by Diehl et al. (2018)[15] and Gerevini et al. (2018)[45] and revealed an interesting potential related to multivariable acting simultaneously in the choke valve and gas lift flowrate.

Oliveira et al. (2015)[46] present an interesting work where one proposes a holistic approach to the anti-slug active control problem in a riser-induced slugging system. This solution is composed of an adaptive controller in the regulatory layer and a model-free optimizer in the supervisory layer that chooses the controllers' set point according to the system stability, aiming to lead the well to its limit. Still in the line of autonomous systems, Pedersen et al. (2014)[47] and Pedersen (2016)[13] proposed an alternative to reduce human intervention in unsteady wells operation through switching model-free PID controllers.

The method proposed in this Chapter intends to treat the static well nonlinearity in the regulatory layer using an easy-to-fit model to plant data. The proposal will be evaluated in real and simulated environment in order to treat riser-induced slugging.

5.3 Methodology

An unsteady oil well presents two main operating regions: one stable and another one featured by a limit cycle, which is characterized by permanent self-sustained oscillations caused by the slugging phenomenon. If a system changes its qualitative behavior to form a limit cycle when a parameter is varied, the singularity is called Hopf bifurcation (Bequette, 1998)[49]. The pioneer works of Storkaas et al. (2001)[50] and Storkaas and Skogestad (2002)[51] were the first to state this transition as a Hopf bifurcation in oil production. Besides, the authors emphasize the loss of process gain from input (choke valve opening) to output (well backpressure) with increasing valve opening, at the same time as a pole moves further into the right half plane. When this occurs, it is practically impossible to stabilize the system with large valve openings.

A typical unsteady oil well bifurcation diagram is shown in Figure 5.1, where PDG (Pressure Downhole Gauge) is the pressure close to the bottom hole and the bifurcation parameter is the choke valve. The loss of the pressure gain, throughout the production valve opening, is a static nonlinearity that becomes critical in unsteady flow wells since the regions with the highest yields are located at the unstable branch. Although it is arduous to stabilize the system at large valve openings, it is still possible to operate the well closer to the optimum point using feedback control. Hence, a nonlinear PID control can be applied to compensate the nonlinearity through online retuning according to the well operating point.

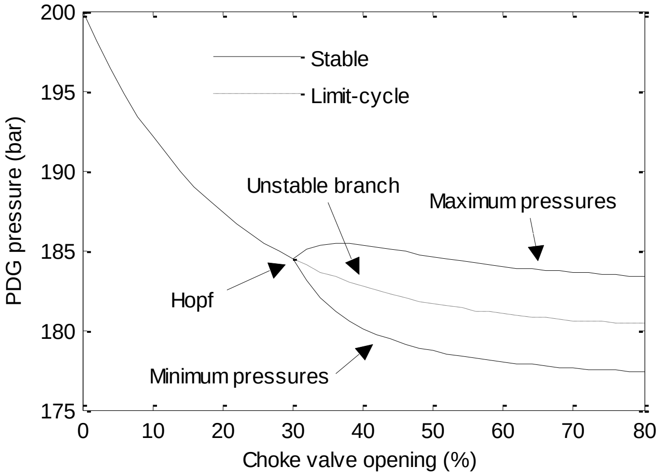

Figure 5.1 – Generic bifurcation diagram of an unsteady oil well.

One way to define the control compensation policy is to obtain the system's equilibrium curve, compute its derivative, and use it to design the controller gain through direct synthesis. To generate this gain scheduling policy, it is necessary to know the well's behavior over a wide range of operational points. Traditionally, to obtain this global knowledge, several open-loop tests in the plant are required, which demands a long time producing in less profitable regions, resulting in financial losses that reduce the attractiveness of this type of approach. An alternative option is to apply numerical continuation techniques (Krauskopf et al., 2007[52]; Kohout et al., 2002[53]; Dhooge et al., 2006[54]; Kasnyk et al., 2007[55]) in a first principle model to approximate nonlinear solutions in order to build bifurcations diagrams and thereafter to obtain the system equilibrium curves. Unfortunately, fitting these models to a real global multiphase flow system is far from a straightforward task.

An alternative to overcome those difficulties would be to use the well's operational database as a source for reconstructing its whole steady-state equilibrium. A methodology based on data historian would make it possible to avoid in situ tests and problems related to modelling a complex phenomenon. Although this idea is promising, the challenge of finding it in the midst of data is not trivial. For instance, Figure 5.2 shows two years of raw data from an actual well, minute by minute, that we will call RO_Y well. It is not possible to obtain a clear perception of how the well behavior is, but somewhere in the data cloud is the equilibrium curve of the system.

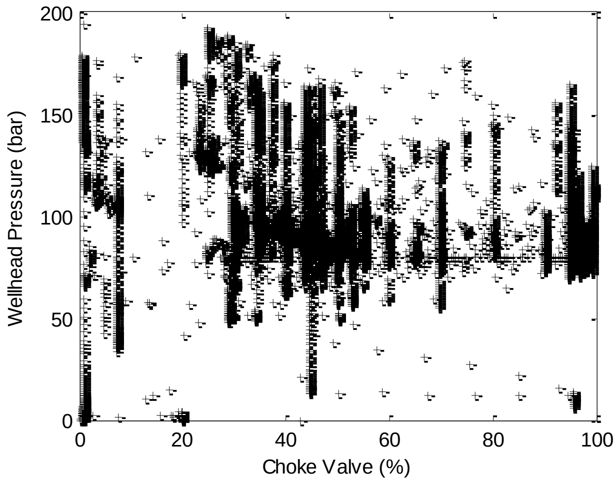

Figure 5.2 – Real well (RO_Y): two years of operating data from the wellhead Temperature and Pressure Transmitter (TPT).

In the next subsections of this chapter, a proposal to map the entire pressure system equilibrium in order to support the nonlinear control policy design will be described. To illustrate the methodology step by step, real operating data from RO_Y, a gas lifted well with stability problems, will be used.

First Principle Model Structure

Jahanshahi and Skogestad (2017)[44] presented a pressure balance defined by Equation 5.1, from wellhead to topside, where P is the wellhead pressure (TPT), P_d is the choke valve downstream pressure, ΔP_v is the valve pressure drop, ΔP_{sh} is the static head contribution and ΔP_f is pressure loss by friction.

$$P = P_d + \Delta P_v + \Delta P_{sh} + \Delta P_f \qquad (5.1)$$

The authors assume P_d and ΔP_f as constant and derive the static gain model in Equation 5.2 to subcritical flow. In this equation, u is the valve characteristic curve, as defined Equation 5.3. Equation 5.4 presents λ, which is a parameter related to production system properties and flowrates at a steady state. In this equation, $(w_G)_{in}$ is the mass flowrate of gas at the inlet of the wellhead, w_{out} is the total mass flowrate in the system, ρ_G and ρ_{ss} are, respectively, the average density of gas and gas-liquid mixture, L is the riser length and g is the gravitational constant. Finally, c_1 comes from the ideal gas law (Equation 5.5), so M_G is the gas molar weight, T is the inner average system temperature and R is the universal gas constant.

$$\frac{\partial P}{\partial u} = \lambda \frac{-2\Delta P_v}{u} \qquad (5.2)$$

$$u = C_V(z) \qquad (5.3)$$

$$\lambda = \frac{1 + \frac{gLc_1\rho_{ss}^2(\omega_G)_{in}}{\rho_G^2\omega_{out}}}{1 + \frac{c_1(\omega_G)_{in}\omega_{out}}{u^2\rho_G^2}} \qquad (5.4)$$

$$c_1 = \frac{M_G}{RT} \qquad (5.5)$$

Considering that the proposed model represents the steady state, the entire flow of gas lift provided by the topside facilities is incorporated into the fluids produced by the well for the λ estimation.

A typical choke valve characteristic curve is presented in Figure 5.3. This kind of valve usually has a nonlinear behavior that can be approximated by a polynomial, as shown in Equation 5.6, or a sigmoid function, for example. In this case, the chosen polynomial has a degree (j) equal to 6. The polynomial coefficients are represented by the matrix a.

$$u = Cvf(z) = \sum_{i=0}^{i=j} a_i z^i \qquad (5.6)$$

Short term observations using rigorous multiphase flow simulator OLGA reveal λ presents few variations even considering pressurized or depressurized operating zones. As shown in Figure 5.4, changes of 50 bar in downhole pressure result in variations smaller than 0.1 in λ. So, one can say λ may be approximated by a constant defined for an operating region of interest.

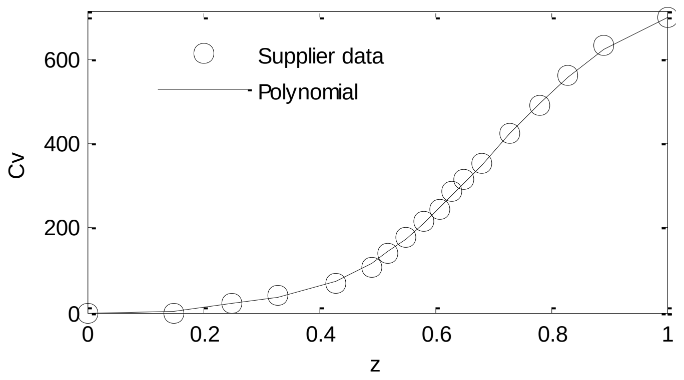

Figure 5.3 – Broadly employed choke valve type.

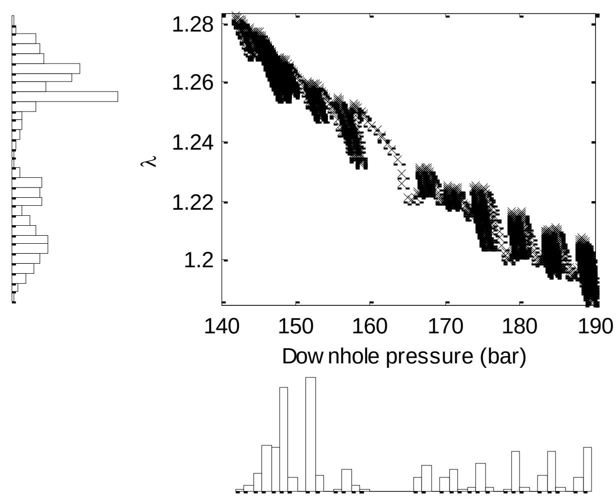

Figure 5.4 – λ behavior from the start to the minimum pressure of a well modeled in OLGA (the secondary bar represents the number of times the value is shown in the data set).

Considering as a start point λ = 1 and applying Equation 5.2 and 5.6 to RO_Y well operation data, as referred previously, Figure 5.5 is obtained. As it can be seen, the data cloud assumes a kind of noisy exponential shape.

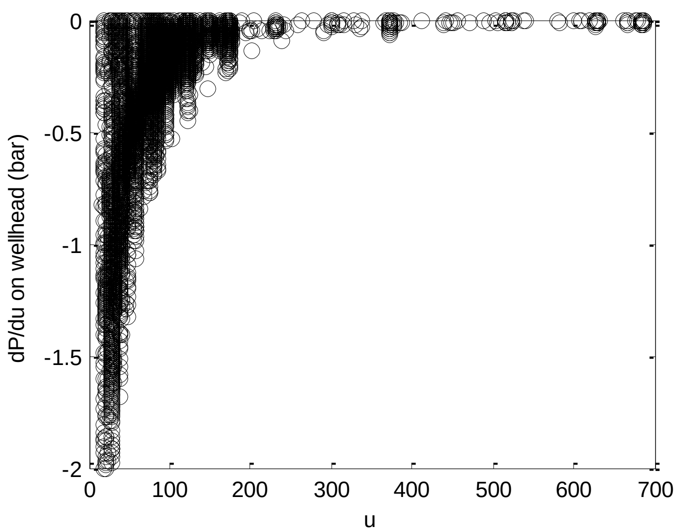

Figure 5.5 - Data cloud of estimated gains formed by 2 years of data from RO_Y well.

Steady-State Detection

Since the system equilibrium curve is fundamentally a stationary behavior, it is important to remove the transient information from the dataset. There are several techniques in literature for steady-state identification. These techniques, however, do not share a common theoretical ground. They are based on different statistical and morphological aspects of the problem. In this context, one can find techniques based on the mean differences along with time intervals (Alekman, 1994[56]; Schladt and Hu, 2007[57]), on standard deviation thresholds (Jubien and Bihary, 1994[58]; Kim et al., 2008[59]), on detection of linear trends (Mahuli et al., 1992[60]; Moreno, 2010[61]; Önöz and Byazit, 2003[62]) and on the ratio of the mean square successive difference to the standard deviation (Von Neumann et al., 1941[63]; Cao and Rinehart, 1995[64]; Bhat and Saraf, 2004[65]). In order to remove transient data from the well operation, we applied a steady-state detection based on the linear regression slope associated with the confidence bounds for coefficient estimates. The output subset generated is presented in Figure 5.6, where it becomes evident the exponential behavior of the system static gain.

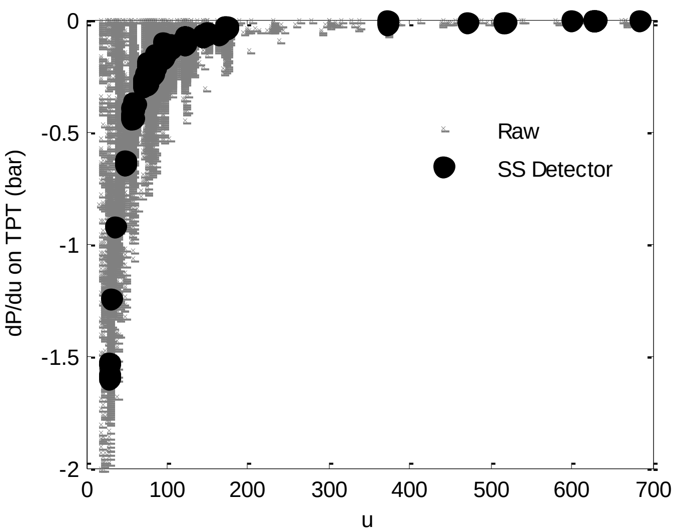

Figure 5.6 - System gain after steady states detection.

Process Equilibrium Correlation

Since the static gain behavior is an exponential feature, it can be approximated by the power-law Equation 5.7. A simple way to find the value of k and n is to apply a linear regression on the logarithmic data transformation, as illustrated in Figure 5.7.

$$\frac{\partial P}{\partial u} = kz^n \tag{5.7}$$

From the integration of the new static gain model Equation 5.7, it is possible to achieve the pressure equilibrium correlation in the wellhead. As the variable u is dependent on the choke valve opening z, as shown in Equation 5.3, it is necessary to change the partial pressure derivative from u to z, as indicated in Equation 5.8.

$$\frac{\partial P}{\partial u}\frac{\partial u}{\partial z} = kz^n \frac{\partial u}{\partial z} \tag{5.8}$$

Deriving Equation 6 concerning z Equation 5.9 is achieved.

$$\frac{\partial u}{\partial z} = \sum_{i=0}^{i=j} i a_i z^{(i-1)} \tag{5.9}$$

Replacing Equation 5.9 in Equation 5.8 results in Equation 5.10, which depicts the wellhead pressure variation directly related to the choke valve opening change.

$$\frac{dP}{dz} = k \sum_{i=0}^{i=j} i a_i z^{(i+n-1)} \tag{5.10}$$

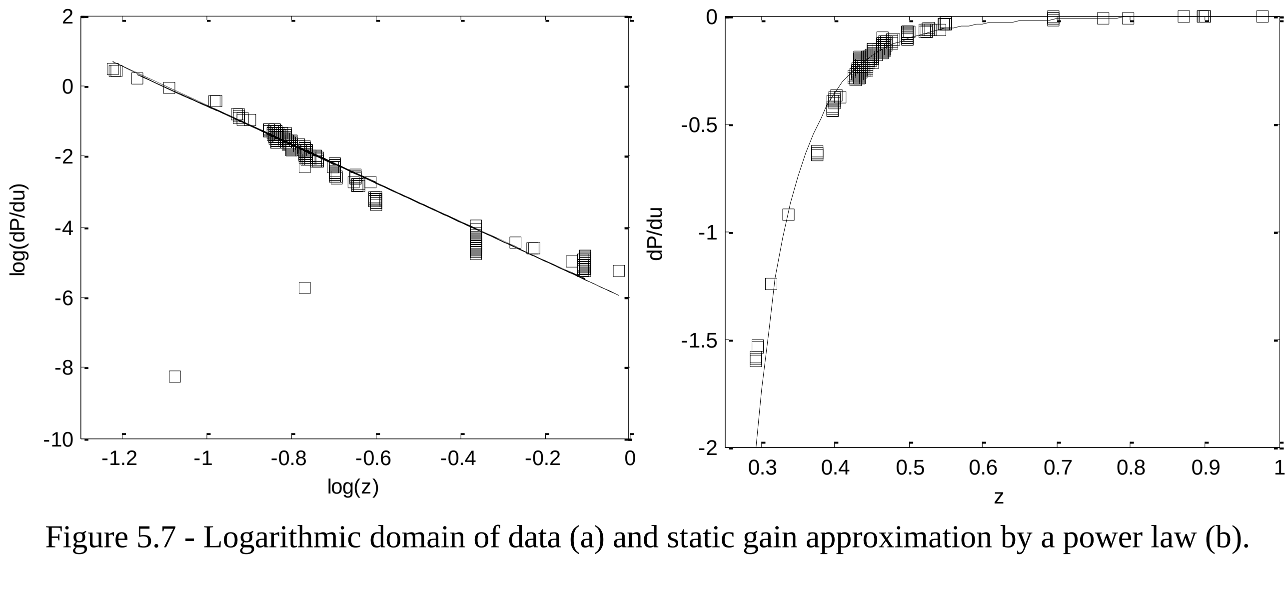

Figure 5.7 - Logarithmic domain of data (a) and static gain approximation by a power law (b).

Integrating Equation 5.10, as shown in Equation 5.11, results in the antiderivatives Equation 5.12 and 5.13.

$$\int dP = k \int \sum_{i=0}^{i=j} i a_i z^{(i+n-1)}\, dz \qquad (5.11)$$

$$\Delta P = k \sum_{i=0}^{i=j} \frac{i a_i}{i+n} z^{(i+n)} + c \qquad (5.12)$$

$$P_2 = k \sum_{i=0}^{i=j} \frac{i a_i}{i+n} z^{(i+n)} + (c + P_1) \qquad (5.13)$$

The integration constant c and the pressure P_1 can be incorporated into β, Equation 5.14. It gives a constant between the model and the plant.

$$\beta = c + P_1 \qquad (5.14)$$

The pressure equilibrium correlation can then be described by Equation 5.15. Figure 5.8 shows the equilibrium curve obtained by Equation 5.15 deployed to RO_Y well data set with $\lambda = 1$.

$$P = k \sum_{i=0}^{i=j} \frac{i a_i}{i+n} z^{(i+n)} + \beta \qquad (5.15)$$

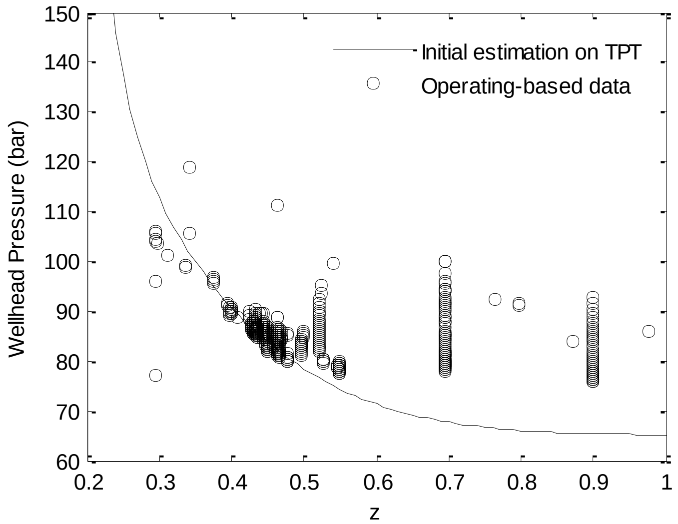

Figure 5.8 – Wellhead equilibrium curve based on Equation 5.15.

Fitting Step

We have experienced that λ can assume a value between 0.5 and 1.5 for our case. This band is an empirical perception obtained through simulations and operating data evaluations from RO_Y well.

In order to find the best constant λ value, it is necessary to solve the minimization problem from Equation 5.16.

$$\min_{\{\lambda\}} \sum_{i=1}^{i=j} [P_e(z_i) - P_{ss}(z_i)]^T \phi [P_e(z_i) - P_{ss}(z_i)] \quad (5.16)$$

In this optimization problem, P_e is the equilibrium pressure estimated for a specified λ and P_{ss} is the real plant steady-state pressure. For each valve position z there is a steady-state plant pressure (P_{ss}) and its corresponding estimated one (P_e). The sub index i refers to a measurement point considered in the problem and j is the total meters used to fit the equilibrium curve to actual data.

It is common to have available up to three relevant pressure meters in an offshore well. These meters are usually located at the bottom hole, wellhead and upstream choke valve. Specifically, in this example, we are going to use the bottom hole (i = 1) and the wellhead pressure (i = 2) measurements in the cost function.

In this case, the estimated pressures at the downhole may be approximated using a steady-state correlation between wellhead and downhole, as shown in Figure 5.9. Note that the lowest pressure zone presents less dispersion between steady states, which is a positive fact, since it is desirable to operate the system in that region.

The weight matrix ϕ can take values according to the user's sense. For example, it is recommended to give more importance to the current operational data and less importance to data located after the Hopf bifurcation - if these data were not removed in steady-state detection stage - and so on. The index i represents the system production samples that one can take to fit the estimates to the plant observations.

The unconstrained optimization problem can be solved by Nelder-Mead algorithm, also called simplex search algorithm, and regarding this case study, the optimized λ is equal to 0.6. The optimized equilibrium set solutions are presented in Figure 5.10.

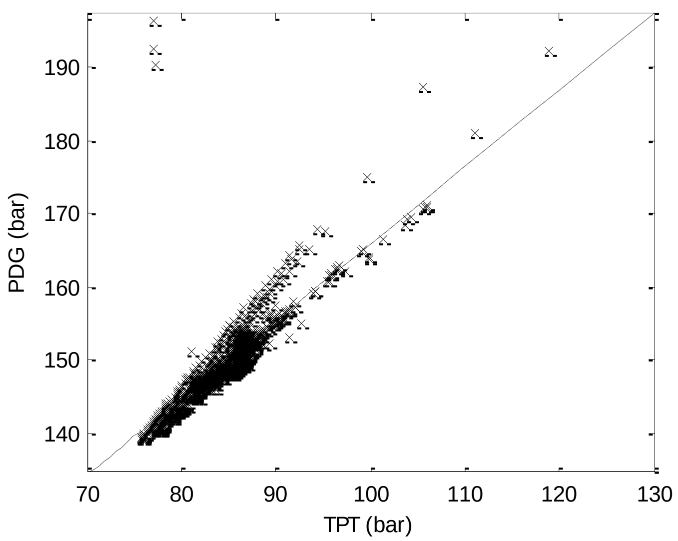

Figure 5.9 - Steady state linear correlation between pressures in wellhead and bottom hole.

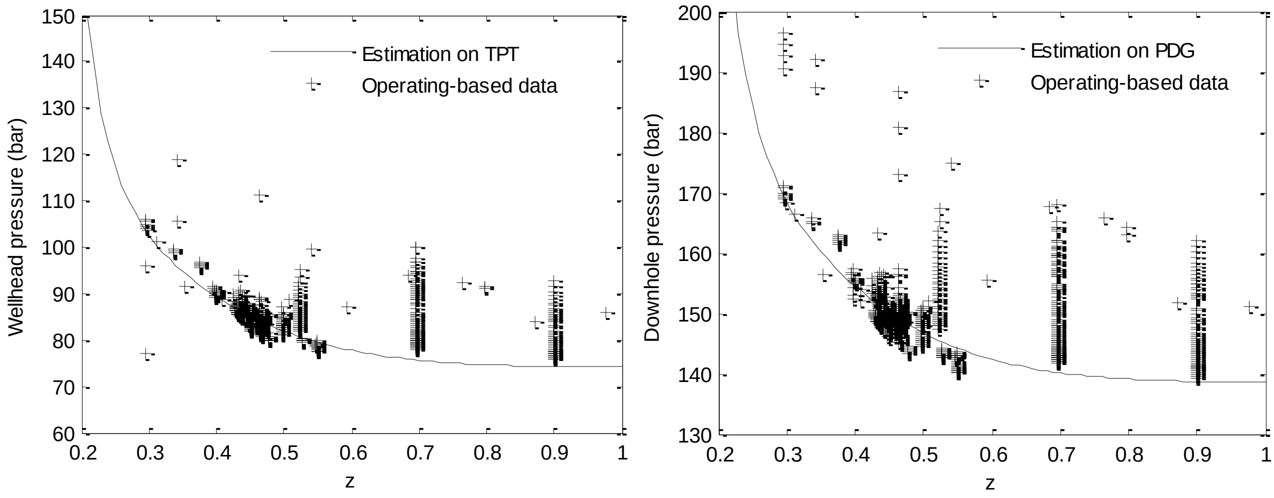

Figure 5.10 - Optimized equilibrium estimation at wellhead (a) and downhole (b).

Gain Scheduling Synthesis

The controller gain scheduling $K_{C,i}$ can be defined based on the inversion of the estimated equilibrium curve derivative, as defined in Equation 5.17. The parameter α is a kind of acceleration factor to the controller that in practice increases its aggressiveness. It might be defined by SIMC rules (Skogestad, 2003)[66], as shown in Equation 5.18, where τ is the time constant, τ_c is the desired closed-loop time constant and θ is the delay.

$$K_{C,i} = \alpha \frac{1}{\frac{dP}{dz}} \qquad (5.17)$$

$$\alpha = \frac{\tau}{\tau_c + \theta} \qquad (5.18)$$

The static nonlinearity can be compensated in the input (z, choke valve opening) or in the output (P, PDG pressure). Figure 5.11 shows the controller gain scheduling to RO_Y well considering $\alpha = 1$.

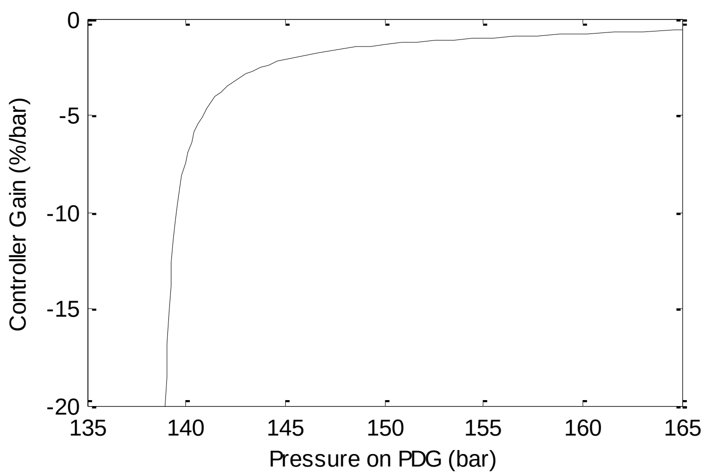

Figure 5.11 - Controller gain scheduling basis related to downhole pressure.

A sensitivity analysis in λ shows that its fluctuation over the well lifetime have a considerable influence on the ideal controller gain as presented in Figure 5.12. A λ adapting strategy might be important to a long-term implementation. However, this issue is not going to be handled in this work.

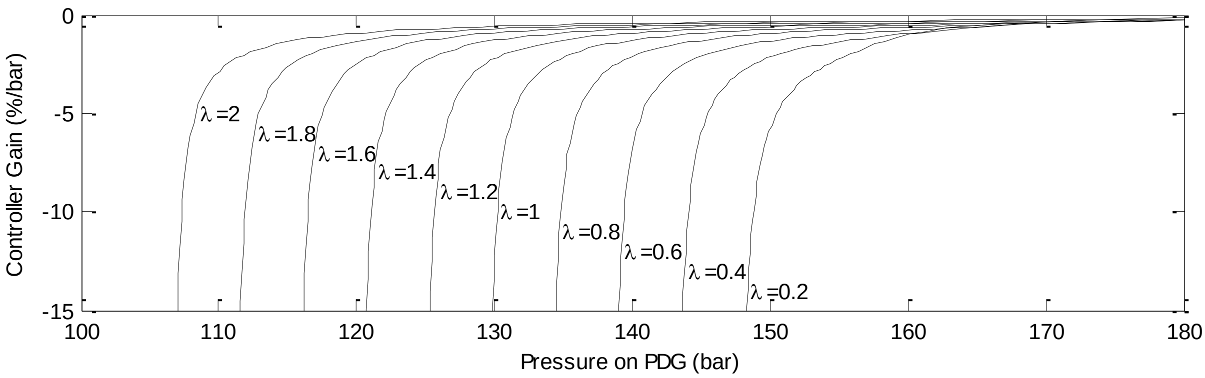

Figure 5.12 – λ influence in the controller gain scheduling.

Systematic Design Procedure

The procedures to obtain the controller gain scheduling can be summarized by the following steps:

1. Define a model to the choke valve: one recommends to fit a polynomial to the valve characteristic curve as shown in Equation 5.6.

2. Create an initial cloud of the process gain: assume $\lambda = 1$ and estimate $\partial P/\partial u$ through Equation 5.2 and operational data.

3. Remove transient data: choose a steady state identification method and apply it to the cloud generated in the previous step.

4. Fit the steady states to a simple morphological structure: find the parameters from Equation 5.7 that approximate the system static data to a power law model.

5. Estimate the initial pressure equilibrium curve: apply Equation 5.15 in order to define the first wellhead pressure equilibrium curve.

6. Tune the equilibrium to the plant data: solve the minimization problem in Equation 5.16 to find the best lambda value. Optionally, it is possible to include more than one well measurement relying on its availability. This step also allows to select more trustable and current subset of data according to the user experience. The answer is not unique and absolute since the well changes its behavior over the time.

7. Generate the controller: apply Equation 5.17 and 5.18 in the previous step data to produce the controller gain scheduling policy. It is recommended to use $\alpha \leq 6$.

In steps 1 and 4 the models can be replaced by any other desired, conserving the main method concept, however in this case the Equation 5.15 will have to be redefined.

5.4 Method Validation

In order to evaluate practical results from the methodology previously described, a validation stage through simulation is accomplished. Three pressures will be used as controlled variables: downhole pressure, wellhead pressure, and upstream choke valve pressure. Therefore a simplified ODE dynamic model was chosen to be the virtual production system. This model was published by Diehl et al. (2017)[67], which is called FOWM (Fast Offshore Wells Model).

The case study addressed in the next sections corresponds to Well A described in Diehl et al. (2017)[67] that is a deepwater satellite gas lifted well from Campos Basin, Brazil, with 1,639 m production columns, 2,928 m flowline touching seabed, and 1,569 m subsea riser. The multiphase liquid produced from Well A (oil + water) has a density of around 900 kg/m³ and 60% of water cut.

Fast Offshore Wells Model (FOWM)

The FOWM model (Diehl et al., 2017)[67] aims at covering a gap in simplified production systems modelling: the whole architecture of satellite wells in deep and ultra-deepwater scenarios. FOWM is based on literature models coupling and it can be divided into three main parts:

- Reservoir-wellbore model: proposed by Vogel (1968)[68] as an empirical correlation, the model consists of a two-phase Inflow Performance Relationship (IPR) used to calculate oil wells production performance. Vogel's model is widely used as wellbore-reservoir interface and it is generally a popular option in commercial flow simulators as boundary condition between reservoir and production column. Despite its static nature, IPR models are suitable options to boundary conditions in flow dynamic simulation if the model is focused on pipelines. This is a reasonable assumption because the flow-pressure response is much faster in pipelines than in the reservoir. So the short-term behavior in the interface reservoir-wellbore might be approximated by an IPR correlation.

- Wellbore-wellhead model: this section is modeled by Eikrem et al. (2008)[39], that is a simple model to describe gas lifted wells from wellbore up to wellhead, in other words it represents the production column segment.

- Wellhead-topside model: consists in the subsea flowlines and riser. It is modeled based on Di Meglio (2011)[69] ideas.

The combination of these works in a single model has resulted in the FOWM, given by Equations 5.19-5.24. In FOWM, the states represent the mass of gas and liquid in different sections of the system: m_{ga} is the gas mass in the gas lift annular, m_{gt} and m_{lt} are respectively the gas and liquid mass in the production column, while m_{gr} and m_{lr} are the gas and liquid mass in the subsea lines and finally m_{gb} is the mass of gas trapped by slugging phenomenon at the subsea production line (elongated buble).

$$\frac{dm_{ga}}{dt} = W_{gc} - W_{iv} \tag{5.19}$$

$$\frac{dm_{gt}}{dt} = W_r \alpha_{gw} + W_{iv} - W_{whg} \quad (5.20)$$

$$\frac{dm_{lt}}{dt} = W_r(1 - \alpha_{gw}) - W_{whl} \quad (5.21)$$

$$\frac{dm_{gb}}{dt} = (1 - E)W_{whg} - W_g \quad (5.22)$$

$$\frac{dm_{gr}}{dt} = E\, W_{whg} + W_g - W_{gout} \quad (5.23)$$

$$\frac{dm_{lr}}{dt} = W_{whl} - W_{lout} \quad (5.24)$$

In essence, the FOWM is a mass balance-based model. Thus, the differential terms are proportional to mass flow relationships, where W_{gc} is the gas lift mass flow entering in the annular, W_{iv} is the gas mass flow from the annular to the production column, W_r is the reservoir to the downhole flow estimation by the Vogel correlation, W_{whg} and W_{whl} are the gas and liquid mass flow at the wellhead, W_g is the flow at the Di Meglio's virtual valve, and W_{gout} and W_{lout} are the gas and liquid flows through the topside choke valve.

FOWM can be fitted to real data through a global unconstrained optimization based on the weighted least squares problem. When the model needs to fit into a limit cycle, an objective function that intends to penalize stable solutions is applied as proposed in Diehl et al. (2017)[67]. Despite this, achieve a good fit might not be a straightforward task, and complementary works as Rodrigues et al. (2018)[70] and Apio et al. (2018)[71] can be useful.

To better understand the FOWM model and its fitting to real data, we recommend the original paper for more details (Diehl et al., 2017)[67].

In order to compare open-loop and closed-loop performance, the production estimation will consider the linear Inflow Performance Relationship (IPR) described in Equation 5.25 and 5.26, where q is the volumetric liquid production, P_{Res} is the reservoir pressure, P_{BH} is the column production bottom hole pressure and PI is the well productivity index. The sub-indexes 1 and 2 refer to the well in open-loop and closed-loop situation, respectively. Well A has a reference liquid production of 2,923 m³/d and a reservoir pressure of 225 bar.

$$q = PI(P_{Res} - P_{BH}) \quad (5.25)$$

$$\frac{q_2}{q_1} = \frac{P_{Res} - P_{BH,1}}{P_{Res} - P_{BH,2}} \quad (5.26)$$

Controller Design

Over 3,500 simulation hours were generated with the objective of producing an artificial industrial data historian. Random steps on the choke valve opening were performed every 24 hours, resulting in a rich collection of operating patterns. Three key variables were monitored: the downhole pressure (PDG), the wellhead pressure (TPT), and the upstream choke valve pressure (TOP). No noise was added to the data. Figure 5.13 shows a sample of this database.

Well A presents a stability loss of around 24% of choke valve opening, which means that a Hopf bifurcation is located at this point. Valve openings over 24% presented a limit cycle pattern in the whole production system.

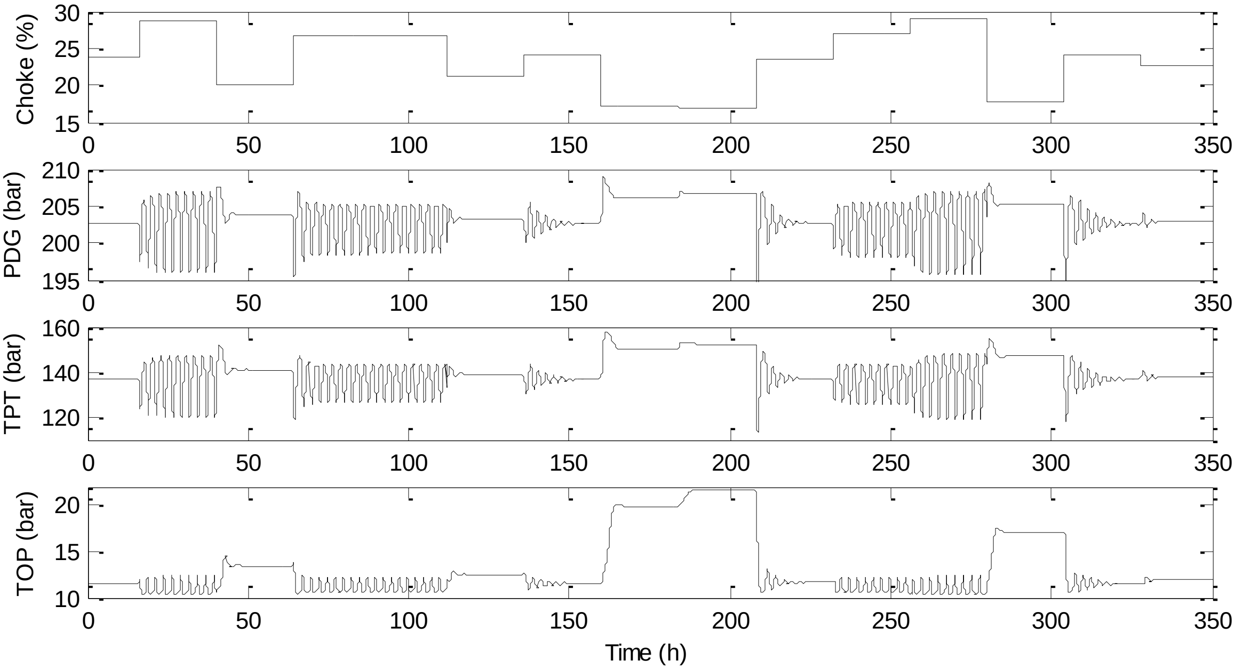

Figure 5.13 – Time domain series generated by random steps on the choke valve opening.

This database was used as an input to the methodology summarized in section 5.3, which produces the estimated system equilibrium shown in Figure 5.14. As it can be noted, only a stable system response was chosen in this validation. The idea is to verify the methodology extrapolation potential to the unstable branch of equilibrium.

Applying the controller design synthesis as defined in Equation 5.17, the gain scheduling profiles presented in Figure 5.15 were obtained. Particularly in this example, the acceleration factor was considered as α=1. The gain scheduling performance will be evaluated in the next sections.

The PID integral (τ_i) and derivative (τ_d) terms have been set, respectively, as $\tau_i = \tau/4$ (where τ is the system time constant) and $\tau_d = 0$ (no significant time delay verified). These terms were kept constant in all operational points.

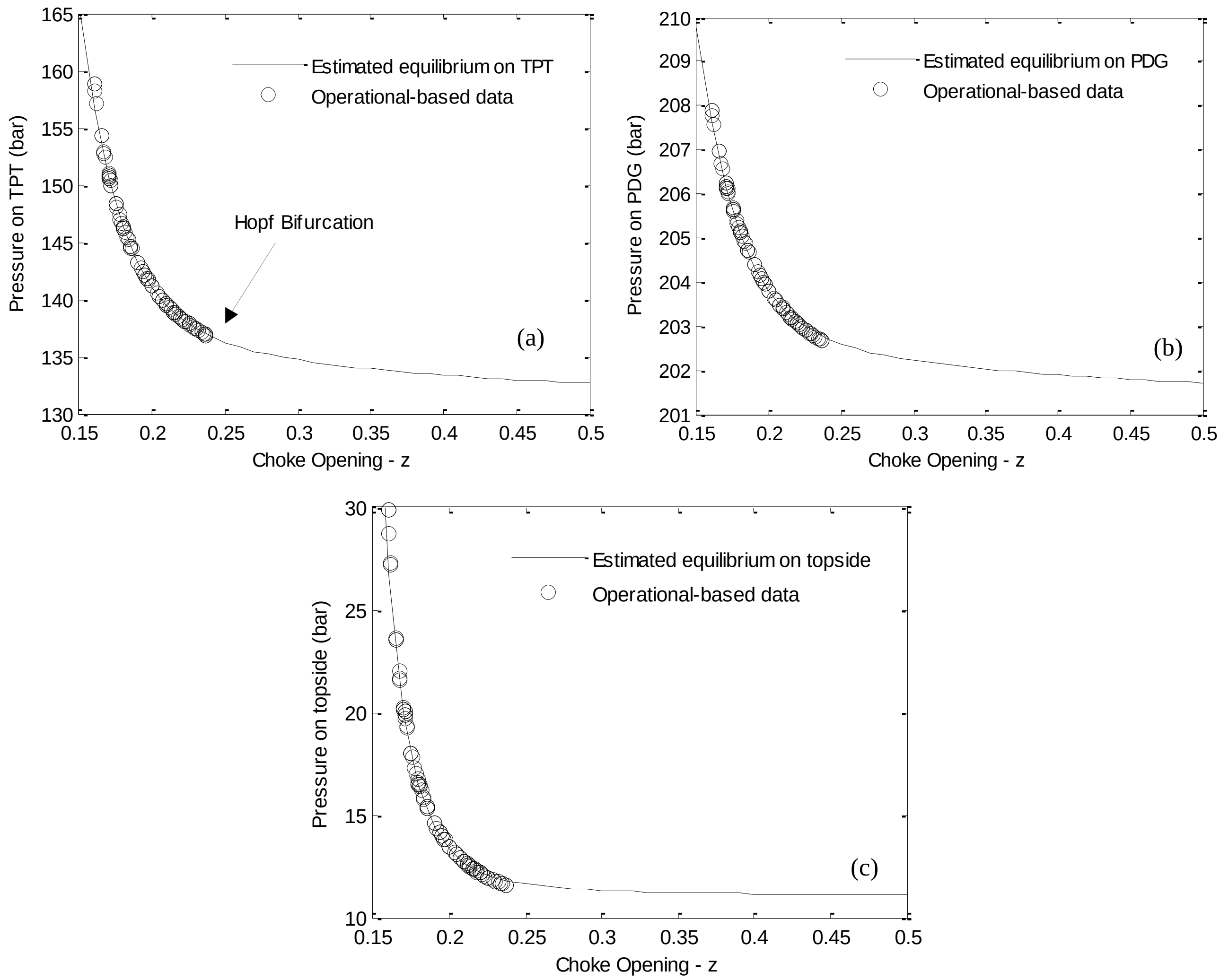

Figure 5.14 – Equilibrium pressure estimated in Well A: (a) wellhead, (b) downhole and (c) upstream choke valve.

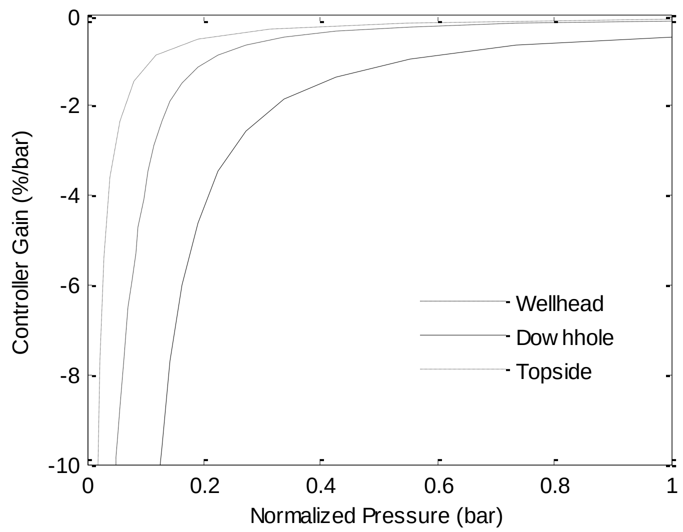

Figure 5.15 – Gain scheduling regarding three possibilities of controlled variables: pressure on the bottom hole, wellhead, and upstream choke valve at topside.

Downhole Pressure as Controlled Variable

The first control structure simulated considers the downhole pressure as the CV and the choke valve as the MV. For comparative performance evaluation, a linear PID tuned equally to its nonlinear version was used, but with a constant gain assumed to be equivalent to the gain scheduling observed at 21% of valve opening. This choice would be natural in a practical situation, once this operating point is stable and close to the Hopf bifurcation, which makes it feasible to an identification test in plant and also representative in its surroundings.

Based on the equilibrium curve, the minimum downhole pressure theoretically achievable is around 201.5 bar. Therefore the simulation test target is to reduce pressure as lower as possible, keeping the system stable, since the lower the pressure at the bottom of the production column, the greater is the well production. The test is presented in Figure 5.16 and summarized in Table 51.

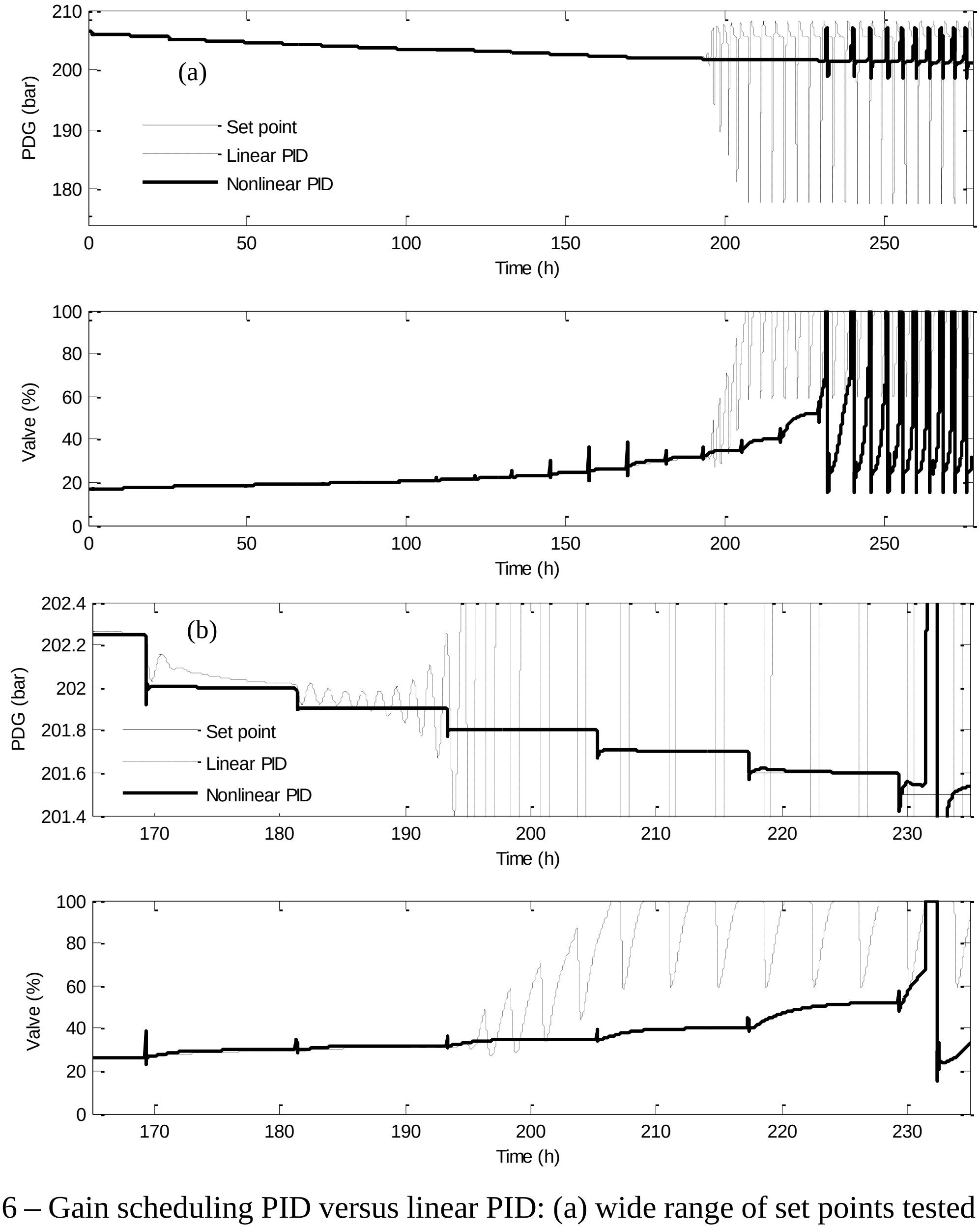

Figure 5.16 – Gain scheduling PID versus linear PID: (a) wide range of set points tested and (b) detail from system instabilization time window.

The nonlinear PID based on gain scheduling was able to reduce the well pressure very close to its minimum at the same time that kept the system running stably. Obviously, when the minimum pressure limit is crossed, even the nonlinear controller loses stability.

Another point that draws attention is how far the choke valve can be unlocked. While the linear PID can open the production valve from 24% to 29.5%, the nonlinear PID allows the choke valve openings up to 52%, which increases about 3 times more in production. This difference can be viewed in the diagram shown in Figure 5.17. Considering the oil price of US$ 50 per barrel, the gain scheduling control strategy has the potential to increase the well profit in 4.8 million dollars per year.

Table 5.1 – Control strategies performance comparison.

	Open-loop	Linear PID	Nonlinear PID
Stability changing: PDG pressure (bar)	202.6 (Hopf)	202.0	201.6
Stability changing: choke valve (%)	24 (Hopf)	29.5	52.0
Liquid production increase (%)	-	2.7	4.5
Oil production increase (bpd)	-	119	331
Potential additional profit (MM US$/year)	-	1.7	4.8

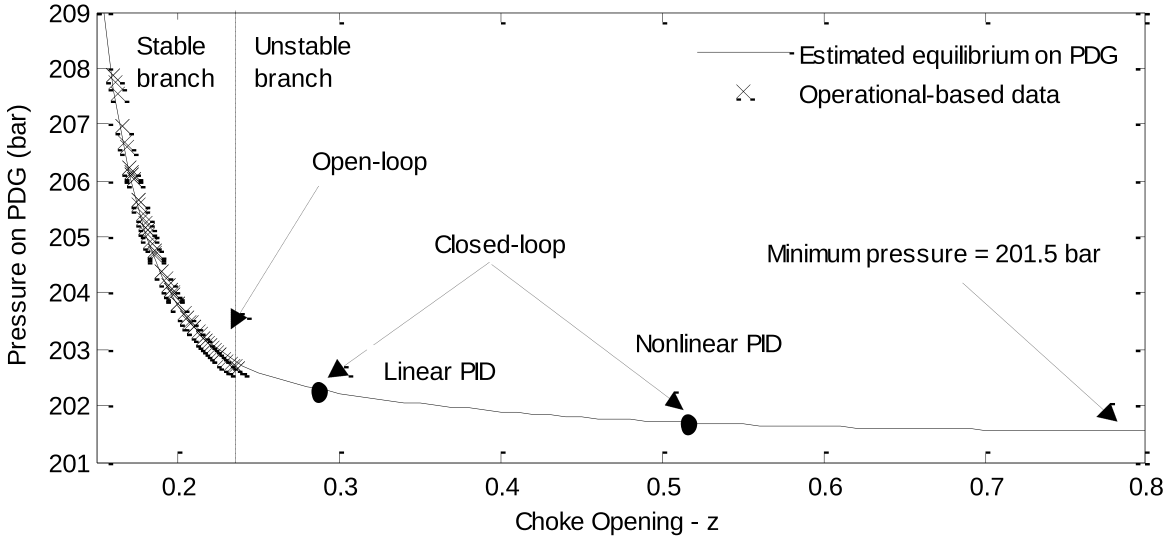

Figure 5.17 – Achievable operating point in stable condition (CV = downhole pressure).

Wellhead Pressure as Controlled Variable

The second control structure evaluated assumes the wellhead pressure as the CV and the choke valve as the MV. The gain scheduling design deployed corresponds to the curve aforementioned in Figure 5.15. Closed-loop performance is presented in Figure 5.18.

As it can be seen, similar performance can be reached using wellhead pressure as CV when compared with previous results using downhole pressure in the loop. This means that using the gain scheduling design proposed makes it feasible to achieve the minimum pressure at well bottom hole (201.6 bar) even controlling the pressure measurement in a different point of the system.

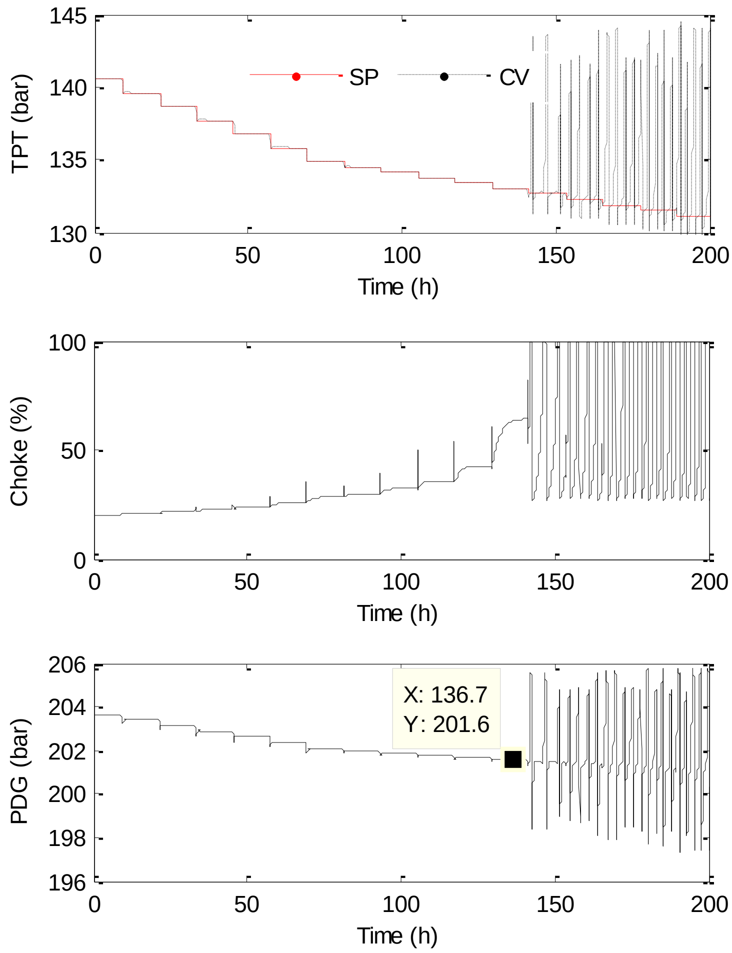

Figure 5.18 – Wellhead pressure-based control structure performance.

Upstream Choke Valve Pressure as Controlled Variable

The last control structure evaluated in this work considers the choke valve upstream pressure as the CV and the choke valve as the MV. The gain scheduling applied was previously described in Figure 5.15, and the controller performance is shown in Figure 5.19.

As a result, the closed-loop stability is guaranteed only in a narrow operating range. In fact, the stability is lost before the open-loop Hopf bifurcation, which means this strategy is not able to counter-attack the unsteady flow. The reason for that comes from the inverse response this structure presents. Figure 5.20 shows the topside pressure response to a unit step on the choke valve location of the production system.

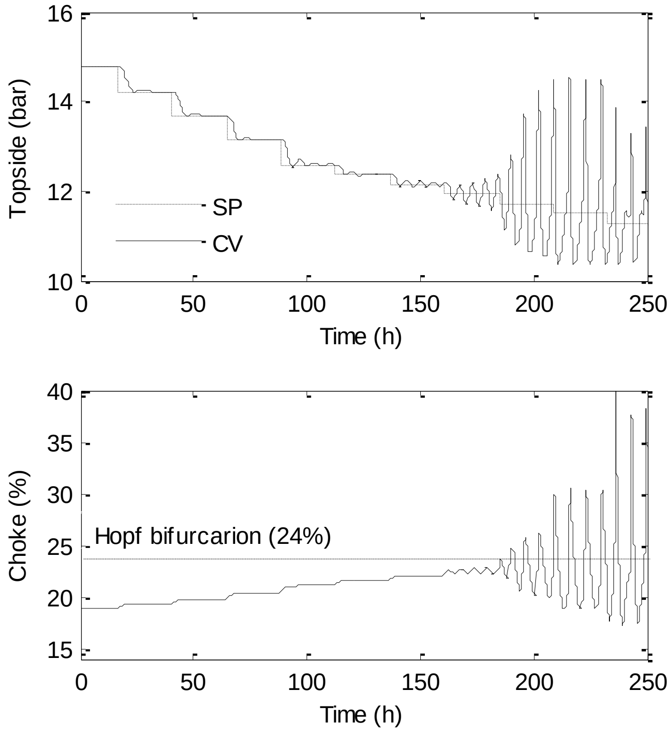

Figure 5.19 – Topside pressure-based control structure performance.

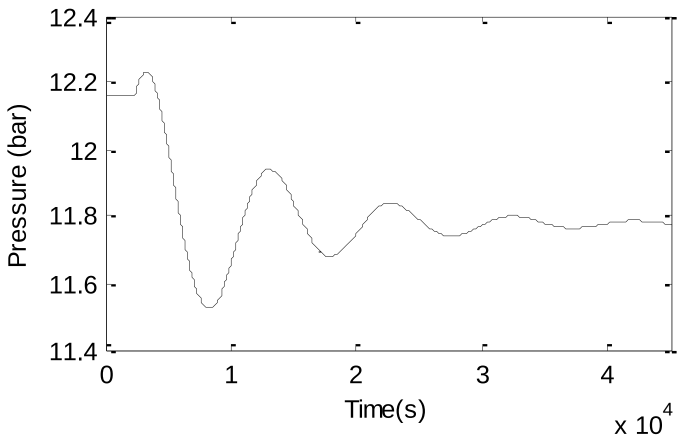

Figure 5.20 – Topside inverse response to unit step on choke valve.

According to Storkaas (2005), the topside pressure measurement cannot be used for stabilizing control due to RHP limitations caused by unstable zeros. The author states that the flow measurement can be used for stabilizing control if used in an inner loop of a cascade controller. Further investigations and contributions in this specific topic were performed by Silvertsen (2008), Silvertsen et al. (2009), and Silvertsen et al. (2010). Highlights for Jahanshahi and Skogestad (2017) work, where a simple flow inference was applied in order to achieve stability through a cascade control strategy. The results are promising, and the application requirements are quite low in terms of instrumentation. Therefore, when assuming topside measurement as the main controlled variable, we recommend considering this work as the current benchmark.

All these works presume that topside pressure inherently has a RHP limitation related to inverse response. This kind of behavior is strongly present in simplified models as FOWM or in rigorous models as OLGA simulator. Nevertheless, we could not see this limitation in actual facilities. Figure 5.21 shows eight different real wells submitted to steps on the choke valve. It seems none of them show an inverse response. Thus, it is considered that this issue requires further investigation.

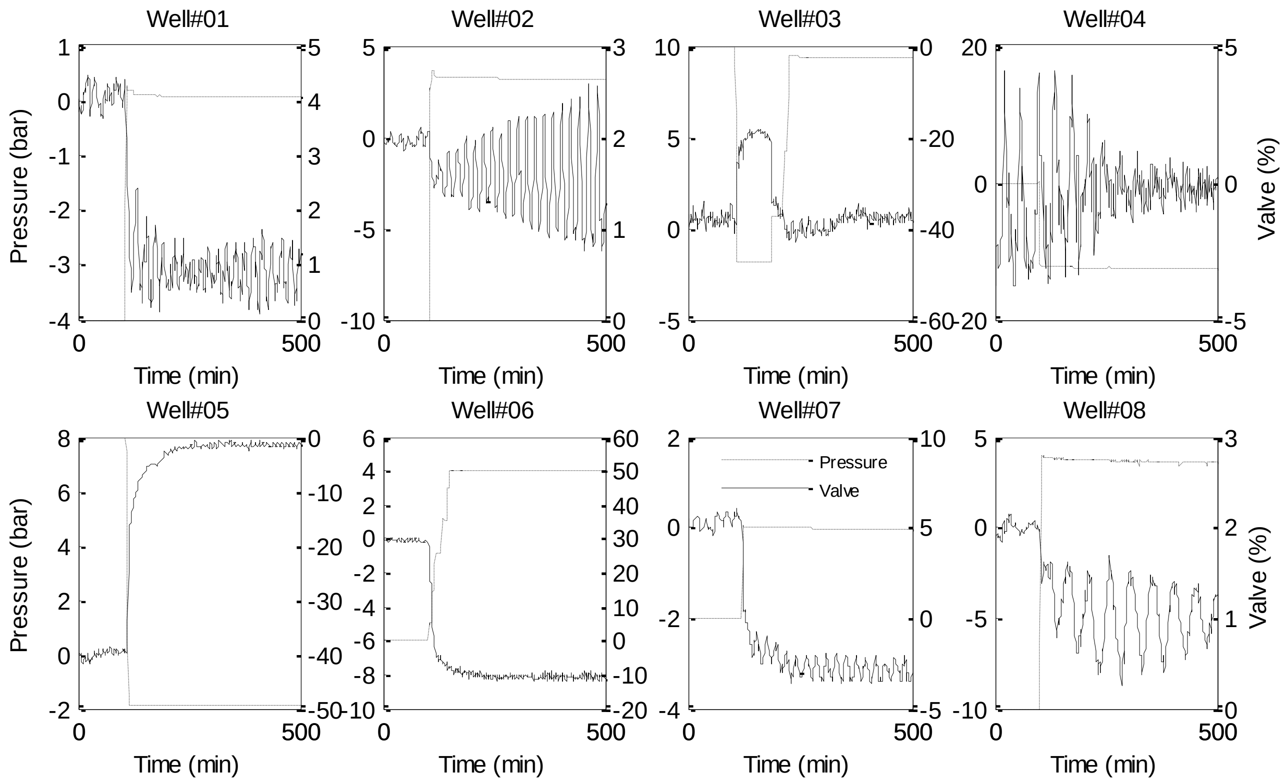

Figure 5.21 – Eight different real well response in topside pressure regarding steps on choke valve.

5.5 Actual Deployment

A real validation study was conducted in a Petrobras oil rig and is described in this section. The Petrobras platform, located at 120 km from the Brazilian coast, has received an active control technology based on the ideas presented in this chapter. The oil field where the platform is installed can be considered an ultra-deepwater facility once its depth is between 1,500-2,000 m. A set of satellite wells produces oil and gas using the gas lift as an artificial method for elevation.

Particularly, for this application, the production system corresponds to the RO_Y well, previously shown in the section 5.3. RO_Y produces an oil with 29 °API, 30% of water-cut and gas/oil ratio (GOR) of 120. Figure 5.22(a) presents the RO_Y well architecture: the wellbore is located around 1,300 m below the seabed and connects the production column to a 6,000 m subsea flowline, followed by a 1,800 m riser line. Complementarily, the pipeline diameter is 6 in; the gas lift valve type is Venturi; the topside pressure in the separator is 9 bar, and the oil flow rate produced is around 1.200 Sm³/d.

RO_Y is usually restricted by the topside choke valve in order to avoid limit cycle formation. Figure 5.22(b) shows two months of operation after a maintenance period. It is possible to see that, most of the time, the choke valve is partially closed around 42-43% to keep stability. This position is exactly where a Hopf bifurcation in the real system is. When operators try to open the valve above that limit, the slugging slowly starts to be formed. After some time, the instability grows to high amplitudes, forcing the operators to return the choke valve position to a more closed state in order to avoid safety issues. This pattern is shown in Figure 5.23. Note how oscillation amplitude might be different in distinct points of the system.

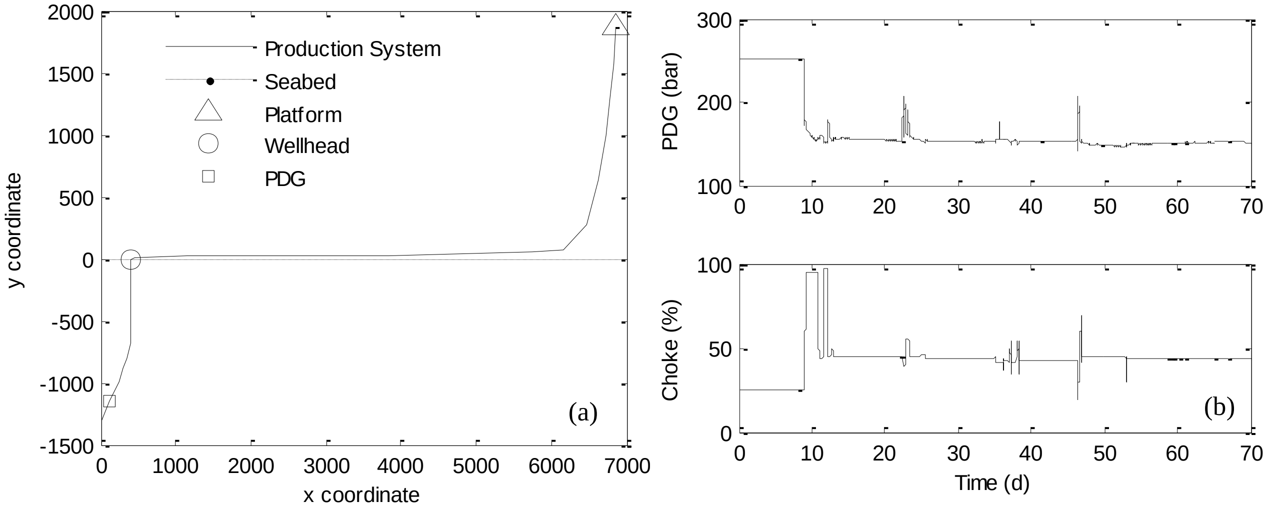

Figure 5.22 – RO_Y well: real production system dimensions in meters (a) and partially closed choke valve to avoid unsteady state flow in oil rig (b).

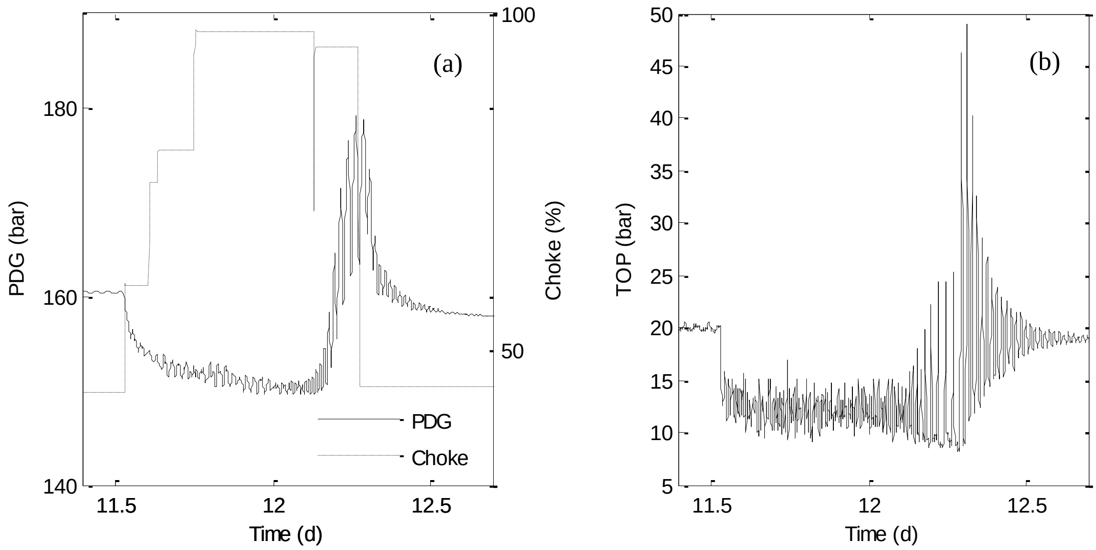

Figure 5.23 – RO_Y instabilization/stabilization through choke valve opening: (a) downhole and (b) upstream choke valve pressure.

The active control solution applied to RO_Y uses downhole pressure (PDG) as the CV and the choke valve opening as the MV. The gain scheduling was designed using the methodology described in this work, and the curve deployed is based on Figure 5.24. Whereas there is no considerable dead time in PDG response, it was chosen as an acceleration factor of $\alpha = 4$ to allow a faster controller performance.

The τ_i and τ_d terms were set as $\tau_i \cong \tau/4$ and $\tau_d \cong \tau_i/5$. Although there is no dead time, observations regarding derivative action showed it could lead to positive effects in limit cycle control. The rules applied to define this tuning were acquired heuristically by the authors' practical field experience in this specific phenomenon.

In the following sections, the control strategy performance will be presented, as well as its capacity to reject disturbance and its financial earning potential.

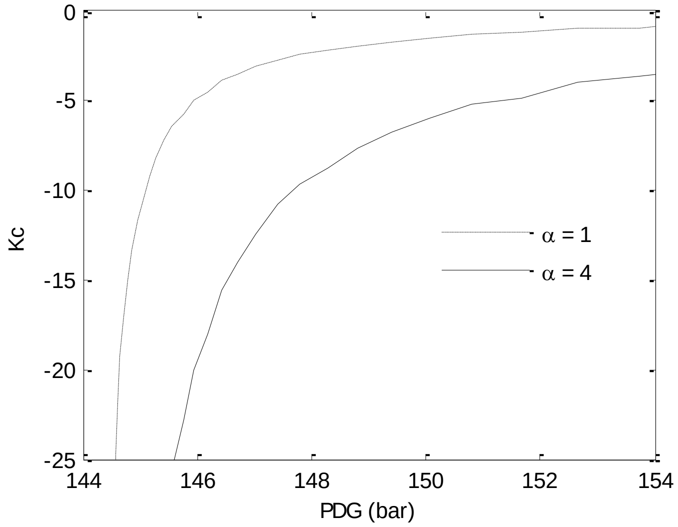

Figure 5.24 – Gain scheduling designed based on data for α = 1 and α = 4.

Actual Closed-Loop Performance

The main goal of an active anti-slug control is to reduce the production system counter pressure safely. As lower the counter pressure is, the higher is the well flowrates, once the flow driving force is the pressure difference and the reservoir pressure is constant in medium term observations. So, the well optimum point is the lowest pressure achievable. Figure 5.25 presents four relevant moments in the anti-slug control performance in RO_Y well.

Firstly, the controller starts from one steady-state nearby Hopf bifurcation at the stable branch of equilibrium - Figure 5.25(a). While the flow pattern is stable, the set point is reduced little by little. The more the pressure decreases, the further "inside" the unstable zone the system is. This requires a MV action intensification. Hence, the variance increases on the choke valve opening, as shown in Figures 5.25(a) and (b).

Along the pressure minimization, the system gain tends to get lower, and therefore, the control actions increase. Figure 5.25(c) shows the controller suppressing the limit cycle amplitude in a low pressure level, around 5 bar from its beginning in open loop.

According to Figure 5.25 and its plant inversion prevision by α = 1, this level of pressure drop is around the minimum feasible pressure in the production system. This means that the controller is very close to its limit in terms of robustness, which tends to be critical to stability. Indeed, the following set point reductions induce a complete loss in the closed-loop performance, and, as result, an instability emerges when the pressure is below 145 bar. Figure 5.25(d) shows the stability loss and recovery through increasing the well counter pressure, which moves the system toward a stable region and retrieves the controller robustness.

Finally, it took 5 days for the controller to reach the minimum system pressure.

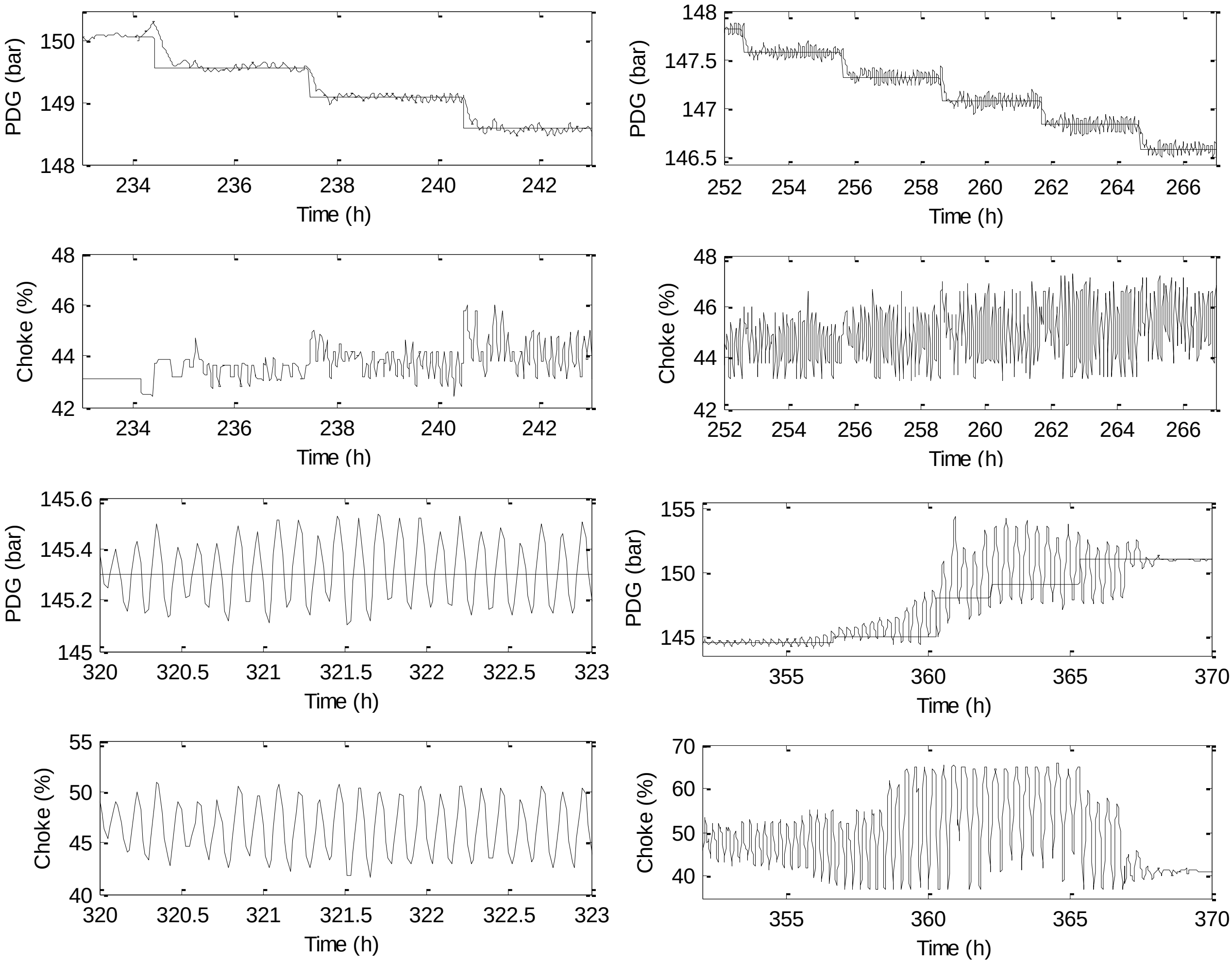

Figure 5.25 – Gain scheduling-based controller applied to the actual production system RO_Y: (a,b) pressure reduction forward Hopf bifurcation; (c) the controller counter attacking slugging; (d) robustness loss due to low system gain, followed by an instabilization and, after that, a stability recovery through pressure fallback.

Disturbance Attenuation

The main disturbances that a gas lifted satellite well might be submitted to correspond to the gas flow rate supply variation and topside pressure discharge fluctuations. The gas lift flow rate has a strong impact on the wells, and it is desirable to reduce the effects of its variance on the production.

The oil rig that RO_Y is connected to makes use of subsea manifolds in order to distribute the gas lift. The gas provision of RO_Y comes from a subsea manifold that feeds the other three wells, which means operational maneuvers in those wells cause a disturbance in RO_Y gas supply.

One example of this kind of disturbance can be viewed in Figure 5.26(a), where the subsea manifold pressure suddenly drops for about three hours. In this period, the gas availability was reduced, inducing a static head increase and leading the flow to a more unstable state. Despite the reduction of 31 bar in the manifold pressure, that is, 14 % of pressure drop, the controller handled the disturbance and kept the system in a profitable zone. A second and even more critical example is shown in Figure 5.26(b). In this case, there was a pressure loss of around 42 bar in the subsea manifold. In other words, a restriction of 19 % in the supply pressure. Once again, the controller handled the disturbance avoiding losses in production.

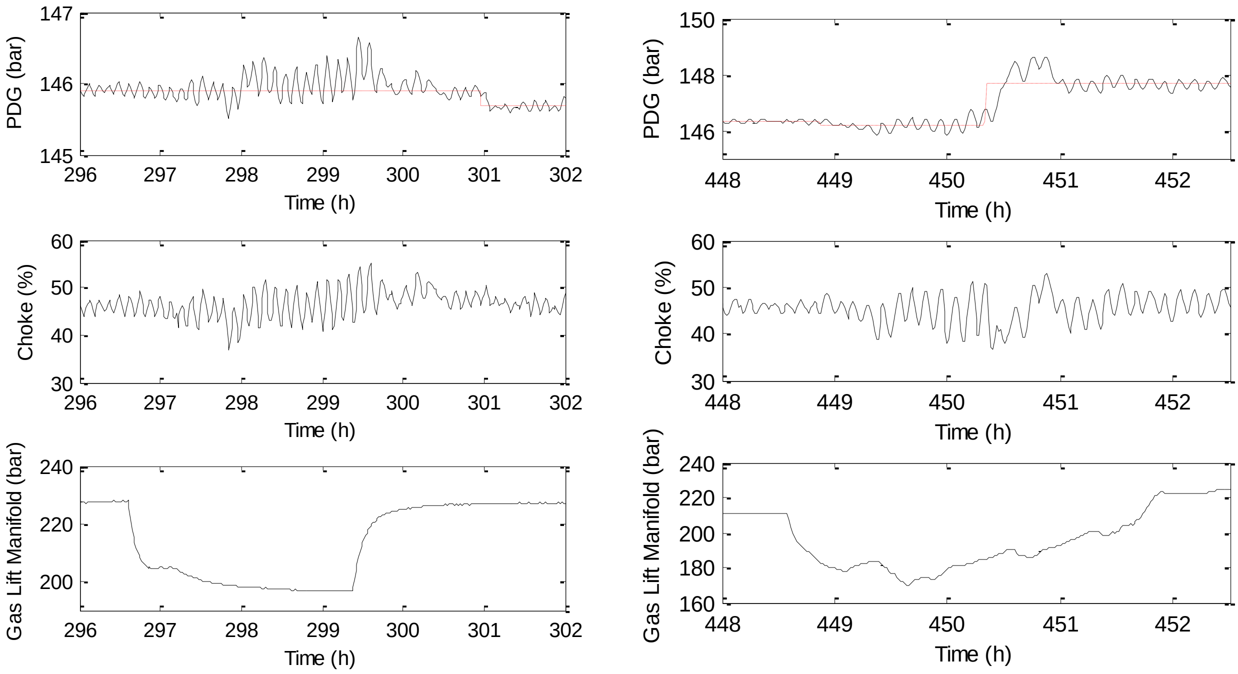

Figure 5.26 – More than 30 bar (a) and 40 bar (b) pressure loss in the subsea manifold gas lift supply, respectively.

Disturbance impact and its rejection ability by the active control solution are more enlightening through Figure 5.27 comparison. The graph shown corresponds to the second disturbance described in this section. Nevertheless, an open-loop well called RO_Z was added in this analysis. RO_Z is a kind of RO_Y's twin well, with similar general characteristics and supplied by the same subsea gas manifold that RO_Y is linked in. So, to compare the disturbance effects in RO_Y and RO_Z is a mean to observe the open-loop versus closed-loop performance in practice.

The difference between maximum and minimum pressures during the disturbance shows RO_Z suffered much more than RO_Y with the gas lift pressure drop. Specifically, RO_Y presented up to 12 times less variation in downhole pressure (PDG) amplitude if compared to RO_Z, while the RO_Y upstream choke valve pressure (TOP) amplitude is up to 65% less than RO_Z. The controller allows RO_Y to operate more safely and profitably when compared with its identical well RO_Z.

Profit Report

Financial aspects of the closed-loop tests were estimated based on the Inflow Performance Relationship (IPR), as described by Equations 5.25 and 5.26. Considering that the lowest pressure reached was 144.5 bar, the oil production increase associated with this level of pressure is around 725 barrels per day, which is equivalent to an increment of more than 9 % in the well production. Assuming US$ 50 as the oil price reference, the well unlockable potential is in the range of 13 million dollars per year.

Taking into account that the pressure meter and the automatic choke valve are already available, it is required a simple computer to deploy this solution, which means that the CAPEX is virtually zero. The financial results and other details are presented in Figure 5.28 and in Table 5.2.

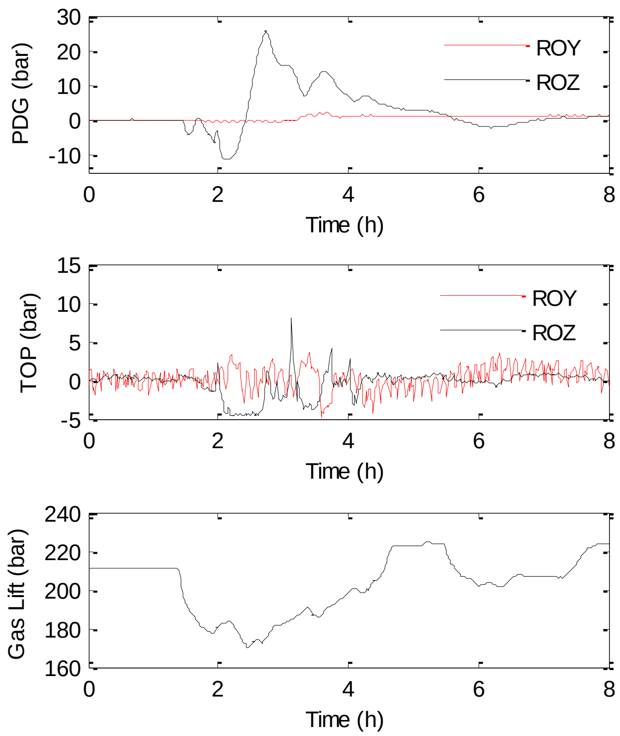

Figure 5.27 – Gas lift disturbance effect in closed-loop (RO_Y) and open-loop (RO_Z) production system.

5.6 Conclusions

In this work, a systematic procedure for anti-slug control design was proposed. The controller synthesis is based on direct plant inversion, and for this reason, it is required to map the static system equilibrium. For that, the method uses the production database to generate a controller gain scheduling relationship and applies it in order to compensate nonlinearities in well operation. This task is not straightforward once the unsteady state equilibrium branch is not the kind of information easily obtained from available well data. In this sense, adding correlations derived from first principle modeling can definitely help.

The methodology was evaluated in two offshore wells: (1) a virtual well represented by FOWM model and (2) a real ultra-deepwater well, both installed on the Brazilian coast. The results showed good capability in getting close to the theoretical minimum pressure and, therefore, to the maximum production achievable while rejecting disturbance in the gas lift supply. A point of attention is that the lower the system gain is, the less robust is the controller, even with high compensation in the controller gain. At a limit gain, any noise could unstabilize the well. Finding out this limit is an open issue and an important matter for future works.

Further, the method can be applied successfully in all control structures based on conventional subsea pressure measurements, i.e., downhole pressure and wellhead pressure.

Regarding financial aspects, the method presented increased oil production through active feedback control solution substantially. In the field deployment, the oil flowrate was increased by more than 9%, which represents a potential of US$ 13 million per year for that specific well – considering an oil barrel price of US$ 50.

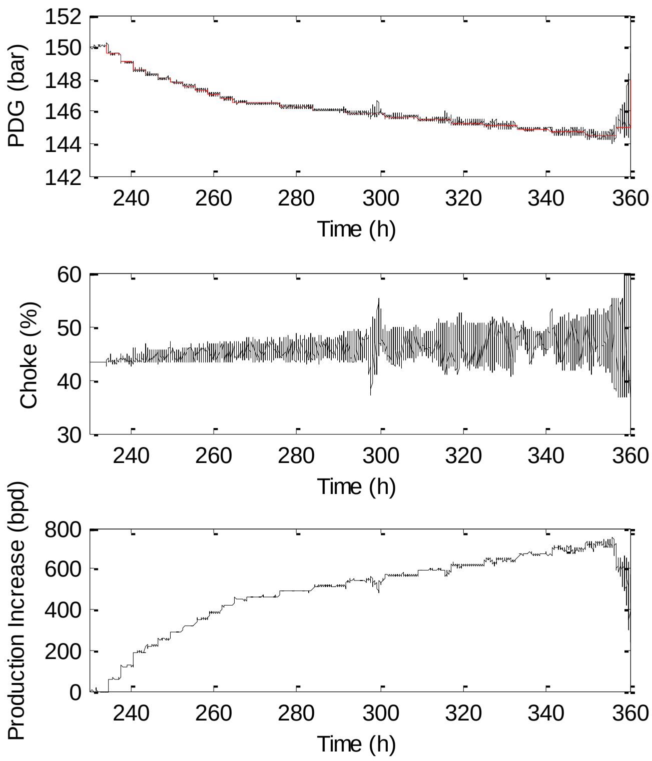

Figure 5.28 – Oil production increase during the tests.

Table 5.2 – Deployment performance summary.

Feature	Value
Hopf bifurcation pressure (bar)	150
Lowest pressure achieved (bar)	144.5
Highest oil production increase achieved (%)	9.3
Highest oil production increase achieved (bpd)	725
Potential earning* (million US$/year)	13.2
Reduction ratio in disturbances spread: downhole	12
Reduction ratio in disturbances spread: topside	2/3

* *Considering highest profit reached and oil barrel price of US$ 50.*

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Capítulo 6

Conclusões e Trabalhos Futuros

Soluções de controle por retroalimentação são atrativas opções para lidar com problemas de ciclo limite em poços de petróleo marítimos, uma vez que este tipo de abordagem não requer intervenções ou investimentos elevados no sistema de produção. Um número significativo de estudos sobre este tema está disponível na literatura nos últimos 40 anos, porém poucas aplicações em campo foram documentadas e divulgadas. Além disso, as implementações reais que estão disponíveis apresentam poucos detalhes e reúnem basicamente casos em ambientes de águas rasas no Mar do Norte. Assim, o principal objetivo deste trabalho foi contribuir para a lacuna de aplicação de controle ativo em campo para o tratamento de golfadas na produção de petróleo.

Os resultados apontam para um bom potencial financeiro na utilização destas técnicas, permitindo ganhos validados em escala industrial da ordem de grandeza de 10% em aumento da produção.

Os capítulos desta tese apresentam suas próprias conclusões específicas sobre cada sub assunto abordado. No entanto, segue uma reflexão sobre os principais pontos e considerações finais deste trabalho:

- Estrutura de controle: a disponibilidade das medições dos poços depende de cada cenário. Porém, um poço bem instrumentado possui medição de pressão e temperatura no fundo da coluna de produção (PDG), na cabeça do poço (TPT) e na chegada da planta de processamento (TOP). A pressão no PDG tem relação direta com a produtividade do poço que pode ser inferida por modelos baseados em IPR (*Inflow Performance Relationship*). Por esta razão, a pressão no PDG foi a principal variável utilizada nas estruturas de controle desta tese e mostrou desempenho satisfatório na redução dos impactos das golfadas nos cenários de poços satélites de águas profundas e ultra profundas. A pressão no TPT possui um potencial de estabilização similar à verificada no PDG, contudo a pressão a montante da válvula *choke* (TOP), no *topside*, apresenta limitações de fase não mínima que se manifestam na forma de resposta inversa em relação válvula *choke*. Pouca discussão tem sido dedicada a este aspecto, mesmo sendo esta medição a mais abundante nos casos industriais – a manutenção dos instrumentos de *topside* requer menos investimento quando comparado a intervenções submarinas ou na coluna de produção.

- Não linearidade: os poços apresentam não linearidade estática da pressão em relação a abertura da válvula *choke*. Esta não linearidade torna-se evidente no diagrama de bifurcação do sistema e mostra que o ganho do poço (dP/dz) reduz a medida em que a válvula *choke* é aberta. Este comportamento resulta na perda gradativa de capacidade de contra-atacar as golfadas, uma vez que a resposta da contrapressão à válvula fica cada vez menor. O resultado é uma baixa robustez do controle nas maiores aberturas da *choke*, onde a contrapressão é menor e a produtividade maior. Isto não significa que uma estratégia de controle linear não possa ser utilizada, mas sim que sua robustez tende a ser menor se comparada a uma estratégia de controle não linear. Portanto, neste trabalho foi proposta uma metodologia de compensação da não linearidade estática do poço através da utilização de controladores PID com *gain scheduling*. A síntese do *gain scheduling* se baseia na inversão da derivada da curva de equilíbrios do diagrama de bifurcação do poço. Como a obtenção desta curva não é trivial, foi proposto um método de aproximação baseado um modelo simplificado e dados de histórico operacional da planta. Os resultados mostraram que o *gain scheduling* proporciona significativa melhora no desempenho do controle quando comparado a sua versão linear e um teste em campo desta estratégia possibilitou o aumento da produção do poço piloto na ordem de 9-10%. Quanto à não linearidade dinâmica, existe uma mudança qualitativa no comportamento transiente do escoamento que é delineada pela bifurcação Hopf, o que confere ao sistema um nível de não linearidade considerável. Todavia, as respostas transientes no ramo estável são semelhantes, o que remete a um baixo grau de não linearidade dinâmica. O mesmo pode ser dito do poço na região de ciclo limite.

- Abordagem preditiva: é uma estratégia interessante para lidar com o comportamento complexo dos poços que apresentam ciclo limite. Esta alternativa permite a predição do efeito do controlador no comportamento do poço e, a partir de então, possibilita a escolha das melhores ações para se atingir os objetivos de controle com o mínimo de esforço nas variáveis manipuladas. O NMPC avaliado no caso de estudo simulado desta tese mostrou resultados promissores, permitindo o aumento estável de mais de 40% na produção se comparado com o mesmo ponto operacional com golfadas, haja vista permite compensar a não linearidade estática e dinâmica do poço concomitantemente. Atenção especial deve ser dada à necessidade de um modelo representativo e rápido o suficiente para ser utilizado em uma estratégia de otimização em tempo real. Os modelos simplificados (EDO) de escoamento multifásico, disponíveis na literatura, não descrevem a arquitetura completa de um poço *offshore* ou apresentam elevada rigidez numérica, fato que dificulta sua utilização em tempo real. Portanto, para contornar esta lacuna, foi desenvolvido o modelo FOWM (*Fast Offshore Wells Model*) que viabilizou a avaliação da estratégia de controle baseada em NMPC com PDG como variável controlada. De um modo geral, o modelo FOWM reproduz bem os principais comportamentos de um poço com escoamento intermitente e pode ser resolvido numericamente com baixo esforço computacional. Uma metodologia de ajuste do FOWM a dados operacionais também é proposta no trabalho, todavia o problema de estimação de parâmetros não é trivial e ainda se mantém como um dos principais desafios da abordagem preditiva não linear. Uma alternativa para redução desta complexidade foi a utilização de uma estratégia MPC ao invés de NMPC, mais focada em um desempenho local na região de interesse, ou seja, próximo à bifurcação Hopf. Para melhorar a capacidade de rejeição de distúrbios, se optou pela utilização do MPC acoplado a um controlador PID. A ideia desta integração consiste no fato de que o PID pode fazer a maior parte do trabalho relativo à rejeição de distúrbios e oscilações, enquanto que o MPC pode ser o principal responsável pela transição de *set point* de pressão. A estratégia se mostrou viável em teste realizado em poço real e foi capaz de alcançar 10% de aumento na produção mantendo a operação estável. Até onde se sabe esta foi a primeira vez que uma estratégia utilizando controle preditivo foi aplicada em poço real para atenuar o problema das golfadas na produção de petróleo.

- Abordagem multivariável: a técnica de elevação artificial mais disseminada na indústria do petróleo é o *gas lift*. A injeção de gás aumenta um grau de liberdade do sistema e a operação do poço se torna naturalmente multivariável. Portanto, nestes casos existem duas variáveis que requerem manipulação, a abertura da válvula *choke* e a injeção de *gas lift*. Para a comunidade de controle de processos é intuitivo o questionamento sobre os benefícios de uma abordagem de controle multivariável para o problema, contudo a discussão sobre o assunto é escassa na literatura. Normalmente, a questão do *gas lift* é vista como um problema estático, onde em termos de estabilidade se busca operar com as maiores vazões possíveis. Sob a ótica da produção, esta condição operacional pode ser um estado subótimo do poço, resultando em baixa produtividade do sistema. Neste trabalho, o *gas lift* foi avaliado em simulação como variável manipulada para estabilização, juntamente com a abertura da válvula *choke*, através do algoritmo NMPC utilizando o modelo FOWM. Como resultado, foi verificado um aumento de mais de 40% na produção do poço estudado, mantendo o ponto operacional médio da malha aberta, ou seja, o ganho verificado se deve exclusivamente a aspectos de estabilização do escoamento. Uma vantagem adjacente da utilização deste tipo de estratégia de controle é a possibilidade de limitar uma faixa de atuação para o *gas lift*, através de restrições no NMPC, de modo consoante com a política de alocação de gás da plataforma de petróleo. Infelizmente, ainda não foi possível testar esta estratégia em campo.

Por fim, fica evidente que diferentes técnicas de controle ativo podem ser empregadas para redução dos impactos do problema das golfadas na produção de petróleo. As estratégias de controle podem ser muito distintas em complexidade e eficiência alcançada, mas mesmo as alternativas mais simples podem trazer benefícios financeiros à unidade. A ordem de grandeza dos ganhos de produção é significativa e justifica o investimento neste tipo de solução.

Trabalhos Futuros

Apesar dos avanços alcançados, uma grande quantidade de desafios em diversas áreas de controle ativo de golfadas ainda precisa de atenção. Alguns pontos relevantes para trabalhos futuros são:

- Estudo de estratégias de controle baseadas em instrumentação de *topside*, ou seja, medição de pressão à montante da *choke*. Esta estrutura de controle apresenta limitações de fase não mínima, mas ao mesmo tempo é a instrumentação mais abundante e de baixo custo de uma plataforma de petróleo.

- Avaliação de opções de controle adaptativo para lidar com o problema das golfadas. Este é um ponto importante e pouco discutido em trabalhos acadêmicos sobre ciclo limite. Os poços mudam de comportamento ao longo dos meses, variando a vazão de líquido e gás produzido, o BSW, a pressão do reservatório e até mesmo a viscosidade dos fluidos quando ocorre a formação de emulsão no escoamento. Esta dinâmica de médio prazo requer resintonia dos controladores, o que nem sempre é uma tarefa simples e direta. Portanto, estratégias de controle capazes de se auto adaptar a estas mudanças teriam uma receptividade muito grande no meio industrial.

- Desenvolvimento de metodologias robustas para o ajuste do modelo FOWM a dados operacionais é uma questão relevante e ainda em aberto. O modelo FOWM pode ser utilizado não apenas em controle preditivo, mas para diversas avaliações de projeto de controladores, como na sintonia ou investigação de novas estratégias. Por ser um modelo de simulação rápida, é possível utilizar o FOWM em estudos computacionalmente intensivos, como no desenvolvimento de algoritmos de *Reinforcement Learning* para operação de poços. Contudo, primeiramente é necessário que o modelo FOWM possa ser facilmente ajustado para diferentes cenários operacionais dos poços.

- Desenvolvimento de algoritmos de diagnóstico de estabilidade e tomada de decisão em relação à definição do *set point* do controlador de golfadas visando, além de automatizar uma atividade supervisionada, encontrar o ponto de menor pressão possível de se operar o poço em modo estável.

- A integração da camada de controle dos poços com uma camada de otimização multipoço, poderia trazer benefícios globais para a unidade, permitindo estender os benefícios discutidos nesta tese para a operação “colaborativa” entre diferentes poços e elementos da planta de processamento. Apesar desta ideia não ser nova, a sua experimentação em ambientes reais ainda é pouco verificada na prática.